FEASIBILITY OF USING RESIDUAL WOODY BIOMASS TO GENERATE ELECTRICITY FOR SONOMA COUNTY

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AB	Assembly Bill
ARB	Air Resources Board
BAAQMD	Bay Area Air Quality Management District
BCA	Benefit-Cost Analysis
Btu	British Thermal Unit
CCA	Community Choice Aggregation
CCR	California Code of Regulations
CF	Capacity Factor
CFR	Code of Federal Regulations
CH4	Methane
CHP	Combined Heat and Power
CO	Carbon Monoxide
CO2	Carbon Dioxide
CO2e	Carbon Dioxide Equivalent
CPC	Community Power Corporation
CPUC	California Public Utilities Commission
dB	Decibel
DOE	Department of Energy
EPA	Environmental Protection Agency
FIT	Feed-In Tariff
GHG	Greenhouse Gas
GJ	Gigajoule
GRC	General Rate Case

GWP	Global Warming Potential
H2	Hydrogen (Gas)
HVAC	Heating, Ventilation, and Air Conditioning
ICE	Internal Combustion Engine
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
kW	Kilowatt
kWe	Kilowatt Electrical
kWh	Kilowatt-Hour
LCA	Lifecycle Assessment
MCE	Marin Clean Energy
MEA	Marin Energy Authority
MJ	Megajoule
MM	Million
MPR	Market Price Referent
MW	Megawatt
MWe	Megawatt Electrical
MWh	Megawatt-Hour
N2O	Nitrous Oxide
NEM	Net Energy Metering
NOx	Nitrogen Oxides
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance

OMB	Office of Management and Budget
OSHA	Occupational Safety and Health Administration
PG&E	Pacific Gas and Electric Company
PM	Particulate Matter
PPA	Power Purchase Agreement
ppmv	Parts Per Million Volume
PUC	Public Utilities Code
PV	Photovoltaic
PWRPA	Power and Water Resources Pooling Authority
RAM	Renewable Auction Mechanism
Re-MAT	Renewable Market Adjusting Tariff
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison
SCP	Sonoma Clean Power
SCWA	Sonoma County Water Agency
SDG&E	San Diego Gas and Electric Company
SGIP	Self-Generation Incentive Program
SO2	Sulfur Dioxide
t	Ton (Metric)
tpd	Tons Per Day (Metric)
VOC	Volatile Organic Compound
WWTP	Wastewater Treatment Plant

EXECUTIVE SUMMARY

The feasibility assessment presented in this report was conducted between January 2011 and August 2013 to assist the Sonoma County Water Agency (SCWA) in its ongoing efforts to reduce its carbon emissions by using electricity generated only from renewable sources. Evolving priorities within the agency—specifically the new SCWA Energy Policy adopted in March 2011—have spurred the water agency to consider expanding its existing renewable generation portfolio, with bioenergy being one potentially attractive alternative given the agricultural base within Sonoma County. To that end, this assessment sought to determine whether it would be feasible and economically beneficial for the water agency to acquire a biomass energy system that could be fueled by organic feedstocks from local sources.

Several technologies exist for converting the energy content of residual biomass (or "green waste") into useful energy for generating electricity. This assessment focused on *thermal conversion* technologies, which use heat to convert solid biomass feedstocks either directly into thermal energy or into other liquid and gaseous fuels that can be combusted to drive an electric generator. Thermal conversion is accomplished using a wide range of related technologies that can be broadly categorized into three groups: combustion, pyrolysis, and gasification. These groups formed the alternatives evaluated in this feasibility assessment.

Based on the strategic and operational objectives articulated by SCWA at the outset of this assessment and throughout its execution, the following five criteria were used to weigh the relative strengths and drawbacks of the three bioenergy alternatives that were evaluated:

- Minimize air pollutant emissions;
- Maximize energy efficiency;
- Maximize feedstock availability;
- Maximize system modularity; and
- Minimize lifecycle cost.

Each of the three bioenergy technologies was evaluated against the criteria listed above in order to select a preferred alternative for a more detailed analysis of its estimated costs and benefits. The evaluation was conducted in an iterative fashion, with increasing levels

of definition being produced until one alternative emerged as being preferable to the other two based on the specific goals established by the water agency. That is not to imply that the preferred alternative was superior to the other two in every dimension of its projected performance, but rather that the chosen alternative was judged to provide the best overall balance in terms of meeting the diverse objectives targeted by the evaluation criteria.

Given the numerous environmental, technical, logistical, and economic trade-offs inherent in the three bioenergy technologies included in this assessment, ***gasification is presently the best alternative*** for the water agency based on overall performance versus risk across the five evaluation criteria. Biomass gasification is a carbon neutral energy source having relatively low air pollutant emissions, high power generation efficiency, low to moderate capital and operating costs, and a range of commercially available modular systems that can use the organic waste produced by the agency's stream maintenance activities as a feedstock to generate electricity, partially offsetting the agency's retail power purchases. Although biomass pyrolysis could provide some additional environmental benefits over gasification, the technology remains under development at a modular scale and thus poses greater risks to the water agency as it looks to acquire additional renewable generation assets in the near term. Biomass combustion, on the other hand, produces unacceptably high levels of air pollutant emissions and has yet to be widely fielded in modular combined heat and power (CHP) applications.

A detailed benefit-cost analysis (BCA) was performed for a pilot-scale biomass gasification system at three candidate sites in Sonoma County. While all of the sites examined would offer benefits to the water agency in terms of reducing greenhouse gas (GHG) emissions, avoiding retail energy purchases, and generating excess electricity for sale to a wholesale power purchaser, only two sites yield a positive return when their monetized benefits are compared with the costs the agency would incur to install and operate a modular biomass gasifier. Consequently, only a long-term lease at the Airport Wastewater Treatment Plant or the R-4 Pump Station can be considered viable investment options at this time. Nearly the same result would be produced if SCWA were to purchase a biomass gasifier outright, since the $1.0-$1.2 million capital cost the agency would incur matches the total lease cost

over an 11-year period. Because the net present value (NPV) for both sites is only slightly positive—particularly given the large costs involved—a sensitivity analysis was conducted to test the robustness of the BCA results over a range of possible scenarios defined by the inherent uncertainty in two key analysis parameters:

1. The annual escalation of retail electricity rates; and
2. The auction price per metric ton of GHG allowances.

The results of the sensitivity analysis indicate that the water agency would have ***a greater than 90% probability of at least breaking even*** by investing in a pilot-scale gasification system. Stated another way, the agency would face a less than 10% chance of suffering a financial loss from securing an 11-year lease for a 100 kWe biomass gasifier at the Airport Wastewater Treatment Plant (the site having the highest projected NPV). The most likely scenario, as indicated by the distribution generated from a Monte Carlo simulation, would be for SCWA to realize a net gain of roughly $100,000 over 11 years. This result should give the water agency greater confidence in the expected return from such an investment, compared with the outcome of the BCA base case alone.

In light of the water agency's goal of delivering "carbon free water" by 2015, the favorable energy policy climate that continues to evolve in California through mechanisms such as feed-in tariffs and net energy metering, and the emergence of distributed generation and community choice aggregators like Sonoma Clean Power as viable alternatives to existing electric utilities, this is a particularly opportune time for the agency to consider acquiring additional renewable energy generation assets. This feasibility assessment evaluated three different bioenergy technologies and found biomass gasification to be the best alternative for a pilot-scale system that could be operated using residual biomass that already is being produced by the agency's stream maintenance activities. This result was confirmed by a detailed benefit-cost analysis, which determined that biomass gasification could provide a *net financial benefit* to the water agency through a long-term leasing agreement that would obviate any significant capital investment. Accordingly, it is recommended that the water agency take the following two courses of action:

Recommendation 1. Sonoma County Water Agency should pursue the acquisition of a pilot-scale biomass gasification system at its Airport Wastewater Treatment Plant.

Recommendation 2. Sonoma County Water Agency should seek out municipal and/or commercial partnerships for procuring additional biomass feedstocks.

There are several other essential considerations in deciding if it would be feasible to scale up the generating capacity of a pilot system to utility-scale. Thus, it also is recommended that the agency further evaluate those factors before making such a decision in the future. Likewise, the analysis and recommendations contained in this report were developed to inform the water agency's strategic planning and investment decisions. Any commitment of public resources also should be supported by more rigorous engineering analyses of the design, installation, and operating requirements of a biomass gasification system. Finally, the policy framework underlying this feasibility assessment continues to evolve; however, recent trends suggest that the results presented in this report are likely to improve further over time given the expanding renewable energy markets and increasing environmental regulations within California and the nation.

I. INTRODUCTION

The feasibility assessment presented in this report was conducted between January 2011 and August 2013 in partial fulfillment of the Master of Public Policy degree requirements for the Richard and Rhoda Goldman School of Public Policy at the University of California, Berkeley. The assessment was conducted on behalf of the Sonoma County Water Agency (SCWA) to assist its ongoing efforts to reduce its carbon emissions and expand its portfolio of renewable energy generation assets. SCWA is a municipal utility that supplies drinking water to more than 600,000 residents of Sonoma and portions of Marin counties. It also provides sanitation services to approximately 22,000 residences and businesses, as well as watershed maintenance and flood protection services. The analysis and recommendations in this report are offered to SCWA to inform the agency's strategic planning and investment decisions, but should not be relied upon exclusively for engineering design purposes.

The author wishes to acknowledge the patient support of the SCWA staff—notably that of Amy Bolten, the agency's former Public Information Officer, as well as Principal Engineer Dale Roberts—for the duration of this assessment. The author also would like to recognize the generous contributions of technical performance and cost data for biomass gasification systems provided by Community Power Corporation (CPC) of Littleton, Colorado. Finally, the author owes a debt of gratitude to Prof. Gene Bardach for his reliable guidance, sharp insights, and timely encouragement throughout the process of completing this assessment.

II. POLICY FRAMEWORK

A combination of evolving California energy law and new administrative priorities at SCWA provided a backdrop for the analysis contained in this feasibility assessment. Specifically, the water agency views itself as a steward of the valuable natural resources it is charged with managing on behalf of Sonoma County residents, and it strives to continually innovate in its efficient and environmentally responsible service delivery. It does this by proactively conserving resources and by adopting environmentally sound management practices being promoted at the national, state, and local levels. The following policy framework directly shaped the assessment of using locally available residual woody biomass as a resource for

generating renewable electricity for Sonoma County. These policies are rapidly evolving; however, recent trends suggest that the conditions underlying this assessment are likely to improve further over time, and thus the results presented here offer something of a lower bound in terms of their future applicability given the expanding renewable energy markets and increasing environmental regulations within California and the nation.

A. Carbon Free Water by 2015

California has undertaken the nation's most ambitious strategy to combat climate change by reducing its greenhouse gas (GHG) emissions from both stationary and mobile sources. The California Global Warming Solutions Act of 2006, enacted by Assembly Bill (AB) 32, seeks to reduce total statewide GHG emissions to 1990 levels by 2020. The California Air Resources Board (ARB) has established a statewide annual emissions limit of 427 million metric tons of carbon dioxide (CO2) equivalent[1] (CO2e), and the state is currently on track to meet that limit based on the timeline laid out in AB 32. In fact, in March 2012, Governor Brown signed Executive Order B-16-2012 to establish an even more aggressive long-term goal of reducing California's GHG emissions to 80% below 1990 levels by 2050 (California Air Resources Board, 2013).

Although not explicitly required to do so by state law, SCWA has taken numerous proactive steps to decrease its total GHG emissions or "carbon footprint" as it is frequently termed. Based on the understanding that minimizing the impacts of climate change will assist the agency in maintaining more secure fresh water supplies for the residents and businesses it serves, its Board of Directors adopted an Energy Policy in March 2011 that establishes the goal of "achieving a net carbon neutral energy supply by 2015," a goal the agency already has nearly met. To do so, SCWA has implemented several measures and projects that have helped to reduce its fossil fuel consumption and GHG emissions, including the following:

- Promoting water conservation to reduce energy demand for delivery and treatment,
- Improving the energy efficiency of various water agency facilities and operations,

[1] GHGs are atmospheric gases that cause global warming, including CO2, methane (CH4), and nitrous oxide (N2O). Each gas has a different global warming potential (GWP) that can be represented as a multiple of the GWP of CO2. This common unit of measurement is termed the carbon dioxide equivalent (CO2e) of a GHG.

- Installing rooftop solar photovoltaic (PV) panels at its administration offices;
- Utilizing a geothermal heat pump in its building mechanical systems; and
- Installing a wind turbine to generate electricity at a wastewater treatment plant.

The water agency is one of the largest electricity consumers in Sonoma County. Thus, these measures will contribute substantially toward the larger goals established for the state by AB 32. The assessment provided in this report addresses a single proposed element of the agency's diverse energy portfolio, namely, using residual biomass (i.e., "green waste") to generate renewable electricity. Considering its setting in largely rural Sonoma County, the water agency recognized the potential to further reduce its carbon footprint by using local sources of green waste from farms, orchards, vineyards, forest thinning, and municipal landscaping as fuel (i.e., feedstock) for a bioenergy system. The agency commissioned this assessment to evaluate the feasibility of that concept, including the identification of local sources of biomass feedstocks as well as a comparative evaluation of available bioenergy generation technologies.

B. Feed-In Tariffs

The large majority of the electricity SCWA purchases (95% in 2012) is procured from the Power and Water Resources Pooling Authority (PWRPA), a group of 9 irrigation districts and 15 water purveyors in central California that collectively manages its individual power assets and loads. SCWA supplements those procurements with purchases from Pacific Gas and Electric (PG&E), the regional public utility, and its own generation. Based on the most recent complete set of consumption data available from the agency (for 2011), SCWA buys roughly 2.8 million kilowatt-hours (kWh) of electricity annually from PG&E at an average price of $0.151/kWh. The agency consequently spends more than $430,000 annually for PG&E electricity, which in addition to the environmental drivers outlined above provides a considerable economic incentive for SCWA to generate its own electricity.

Assembly Bill 1969, enacted in 2006, added section 399.20 to the California Public Utilities Code (PUC) and established the state's feed-in tariff (FIT) mechanism for small, renewable electricity generators. This pricing and purchasing mechanism, which guarantees 1) access to the state's electrical grid, 2) limited participation in its wholesale electricity market, and

3) fair compensation from retail sellers for delivered renewable electricity, arose from the state's Renewables Portfolio Standard (RPS) established in 2002 with the passage of Senate Bill (SB) 1078. California's RPS program, which was later amended by SB 107 (2006) and SB 2 (2011), requires most of the state's retail power sellers to increase their procurement of electricity from eligible renewable sources to 33% by 2020. The RPS and FIT programs together create reliable financial incentives for small, independent renewable electricity generators to increase their generation capacities beyond their own consumption needs. Such is the case for SCWA, which in addition to its desire to offset its retail purchases of electricity, would like the option of generating excess renewable electricity for sale on the wholesale market as a means of supplementing agency revenues.

Since the enactment of AB 1969 in 2006, both SB 32 (2009) and SB 2 (2011) have amended section 399.20 of the PUC to increase the eligible capacity of an electric generation facility from 1.5 megawatts (MW) to 3.0 MW, and to establish a new FIT pricing mechanism. This new mechanism, the Renewable Market Adjusting Tariff (Re-MAT), will replace the existing tariff structure, which is based on a uniform statewide "market price referent" (MPR) set annually by the California Public Utilities Commission (CPUC). The Re-MAT pricing model, which was adopted by the CPUC in 2012 but remains under administrative review pending approval of a new standard contract and rate structure, instead will utilize a more market responsive pricing mechanism having the following components:

- A starting price based on the weighted average of the highest executed contract price by the state's three large investor-owned utilities (PG&E, Southern California Edison [SCE], San Diego Gas & Electric [SDG&E]) at the CPUC Renewable Auction Mechanism (RAM) auction held in November 2011;
- Different starting prices for the three distinct FIT product types: baseload, peaking as-available, and non-peaking as-available;
- A bi-monthly price adjustment schedule that may increase or decrease the price for each product type every two months based on market response; and
- A time-of-delivery price adjustment based on the generator's actual energy delivery profile and the individual utility's time-of-delivery factors.

More recently, SB 1122 (2012) created specific quotas within the state's FIT program for bioenergy projects. This bill requires California's electric utilities to procure an additional 250 MW of generating capacity from developers of bioenergy projects (above the 750 MW of renewable capacity mandated by earlier FIT rules), with explicit carve-outs created for various categories of bioenergy resources, as follows:

- 110 MW for biogas from wastewater treatment, municipal organic waste diversion, food processing, and co-digestion;
- 90 MW for dairy and other agricultural bioenergy; and
- 50 MW for bioenergy using byproducts of sustainable forest management.

C. Net Energy Metering

Along with the incentives provided by the FIT program to develop new renewable energy sources in California, AB 920 (2009) created a further requirement for the state's electric utilities to offer net energy metering (NEM) to its customer-generators whose renewable electricity generation exceeds their onsite demand. This original NEM program applied only to wind and solar projects, but was expanded in 2011 by SB 489 to include all other eligible renewable energy sources defined in the state RPS. Unlike the FIT program, which essentially acts as a long-term (typically 10, 15, or 20 years) power purchase agreement (PPA) between a renewable electricity generator and the electric utility providing retail sales, a NEM agreement requires end users of electricity to be compensated for their net surplus generation in the absence of a FIT agreement, either through direct payment at a pre-established rate for the value of the net surplus electricity generated in a 12-month period, or through application of credits toward kilowatt-hours of electricity subsequently supplied to the customer-generator by the electric utility. This greater flexibility over the FIT program further incentivizes small (up to 1.0 MW) distributed generators that might not want to enter into a long-term tariff contract to invest in renewable energy projects. It should be noted that the current FIT program prohibits renewable energy projects from also participating in a NEM program with an electric utility, or from applying for subsidies through the state's Self-Generation Incentive Program (SGIP).

SB 594 expanded the state's NEM program in 2012 by allowing the aggregation of multiple meters on a single property where a renewable generating facility is located, as well as on all other properties adjacent or contiguous to that property if those properties are also owned, leased, or rented by an eligible customer-generator. Additional legislation (SB 43) has been proposed to expand the NEM program further by allowing utility customers to participate in "virtual net metering" through the application of credits to their electricity bills for energy produced at off-site renewable generation facilities. This would provide even greater incentive and opportunity for distributed renewable generators to enter the wholesale electricity market regardless of their own onsite energy demand, and would in effect close a loophole in SB 594 by allowing customer-generators with non-contiguous metered properties to be credited by their electric utilities for their aggregate net surplus electricity generation.

D. Community Choice Aggregation

Following deregulation of California's electricity market in 1996 and the resulting energy crisis of 2000-2001, the state instituted a new policy allowing consumers to choose how they purchase electricity. Community Choice Aggregation (CCA), established by AB 117 in 2002, is a mechanism that permits cities and counties (or groups thereof) to generate and supply electricity to consumers within certain geographic boundaries, in direct competition with regional public electric utilities. CCA programs typically offer consumers alternatives such as partially or fully renewable electricity, which may be provided at a premium, while relying on the existing transmission and distribution infrastructure of the regional electric utility (e.g., PG&E). Several communities have established CCA programs, including the City and County of San Francisco and Marin County. The Marin Energy Authority (MEA) is the not-for-profit public agency that administers California's first CCA program, Marin Clean Energy (MCE). Given its location adjacent to Sonoma County, MCE represents a potential wholesale purchaser of any excess electricity that SCWA may produce from its expanding portfolio of renewable generation assets after meeting its own internal demand for carbon free energy (Local Government Commission, 2006).

Another more direct market for excess electricity generated by the water agency would be the new CCA program being established through a joint powers authority formed by SCWA and Sonoma County. This new entity, Sonoma Clean Power (SCP), is currently undergoing regulatory review by the CPUC and is scheduled to begin providing electric service to some county residents, businesses, and institutions in 2014. Full rollout of SCP electric service is expected to be completed within three years. SCP initially will offer its customers a 33% renewable power mix (compared with the 20% of renewables in the current PG&E power mix) and intends to ramp up the contribution of renewable sources in succeeding years. Notably, the rates forecast for electricity supplied by SCP range from 1.8% below to 1.1% above current PG&E rates for residential customers, and from 3.1% below to 0.5% above PG&E rates for commercial customers, thus offering an extremely competitive alternative for electricity consumers while fostering more rapid reduction of GHG emissions (Sonoma County Water Agency, 2013).

III. BIOENERGY ALTERNATIVES

Several technologies exist for converting the energy content of biomass into useful energy for generating electricity. These conversion technologies can be classified into two broad categories: biochemical conversion and thermal conversion. *Biochemical conversion* such as anaerobic digestion or fermentation relies on various microorganisms to break organic materials into their constituent chemical components, some of which can be combusted directly to fuel a steam or gas turbine (e.g., methane) or refined into various liquid fuels (e.g., bioethanol). *Thermal conversion*, on the other hand, uses heat to convert biomass materials either directly into usable thermal energy or into multiple liquid and gaseous products that then can be combusted to drive an electric generator. Thermal conversion can be accomplished using a range of related (and sometimes overlapping) technologies that can be categorized into three primary groups: combustion, pyrolysis, and gasification. These three groups of technologies are described below, and form the three alternatives considered in this feasibility assessment. Because the water agency already had examined a renewable energy project using anaerobic digestion, the focus of this study was limited to thermal conversion. Each alternative was evaluated across five distinct criteria described

later in this section, with the best performing alternative being selected for further review in a subsequent benefit-cost analysis.

A. Alternative 1: Combustion

The most commonly used thermal conversion technique for generating electricity from a range of biomass feedstocks—as well as from fossil fuels—is combustion. This technique relies on the direct incineration of biomass in the presence of high quantities of oxygen to generate heat that can be used to boil water to drive a steam turbine. Some advantages of combustion include its relative technical simplicity, its wide and well-understood use in electrical generation facilities, and the great flexibility in feedstocks that it allows. A major drawback of combustion is the high levels of air pollutant emissions it produces. This is not necessarily a "deal breaker" for the current analysis, however, as prior inquiries by SCWA have found that much of the green waste produced in Sonoma County currently is sent to landfills where it can produce greenhouse gases having a high global warming potential (GWP)—such as methane (CH4)—through anaerobic decomposition. Utilizing that green waste as a feedstock for combustion could therefore reduce the county's GHG emissions from a lifecycle perspective, although the technique poses other challenges due to the ash generated from incomplete combustion.

B. Alternative 2: Pyrolysis

Pyrolysis is a thermochemical process used to decompose organic materials into several other compounds at high temperatures and in the absence of oxygen. Unlike combustion, an ideal pyrolytic reaction does not emit any CO2 because the carbon in the biomass is not able to combine with oxygen from the atmosphere as in a combustion reaction. Rather, it produces a charcoal-like byproduct called biochar, a solid residue that is valued as a soil amendment and that simultaneously provides carbon sequestration. This unique feature initially made pyrolysis an intriguing conversion alternative for SCWA. The useful energy produced during pyrolysis takes the form of several combustible gases (carbon monoxide [CO], hydrogen [H2], and CH4) along with a viscous bio-oil that either can be combusted directly (e.g., as a substitute for heating oil in a boiler), upgraded using various chemical processes to other types of higher grade liquid biofuels (e.g., replacement transportation

fuels), or used as a feedstock for gasification (a process that is described below). Although pyrolysis is a relatively new thermal conversion technique for generating electricity, it has been used for centuries to turn wood into charcoal for cooking, as well as for metallurgical purposes such as converting coal into coke for steelmaking.

C. Alternative 3: Gasification

Representing a sort of thermochemical middle ground between combustion and pyrolysis, gasification is a partial oxidation process that has been used to produce synthesis gas (also known as syngas) since the 1800s. Like the combustible gases produced along with bio-oil in a pyrolysis reaction, syngas is a mixture of mainly CO, H2, and CH4, which can be used to fuel a steam or gas turbine as well as an internal combustion engine (ICE). Gasification is conducted in a carefully controlled, reduced oxygen environment and consequently does produce CO2, unlike an ideal pyrolytic reaction which does not. This thermal conversion process does not, however, suffer from some of the drawbacks of combustion, in particular the latter's high emissions of particulate matter (PM), volatile organic compounds (VOCs), and CO. Therefore, gasification may provide additional environmental benefits other than the reduction of CO2 emissions. This and several other factors were used to compare the three primary types of thermal conversion technologies to determine which could offer the water agency the most attractive alternative for converting residual biomass to electricity. Figure 1 depicts the process stream for each of the three thermal conversion technologies.

D. Evaluation Criteria

Based on the strategic and operational objectives articulated by SCWA at the outset of this feasibility assessment and throughout its execution, the following five criteria were used to weigh the relative strengths and drawbacks of the three bioenergy alternatives:

- Minimize air pollutant emissions;
- Maximize energy efficiency;
- Maximize feedstock availability;
- Maximize system modularity; and
- Minimize lifecycle cost.

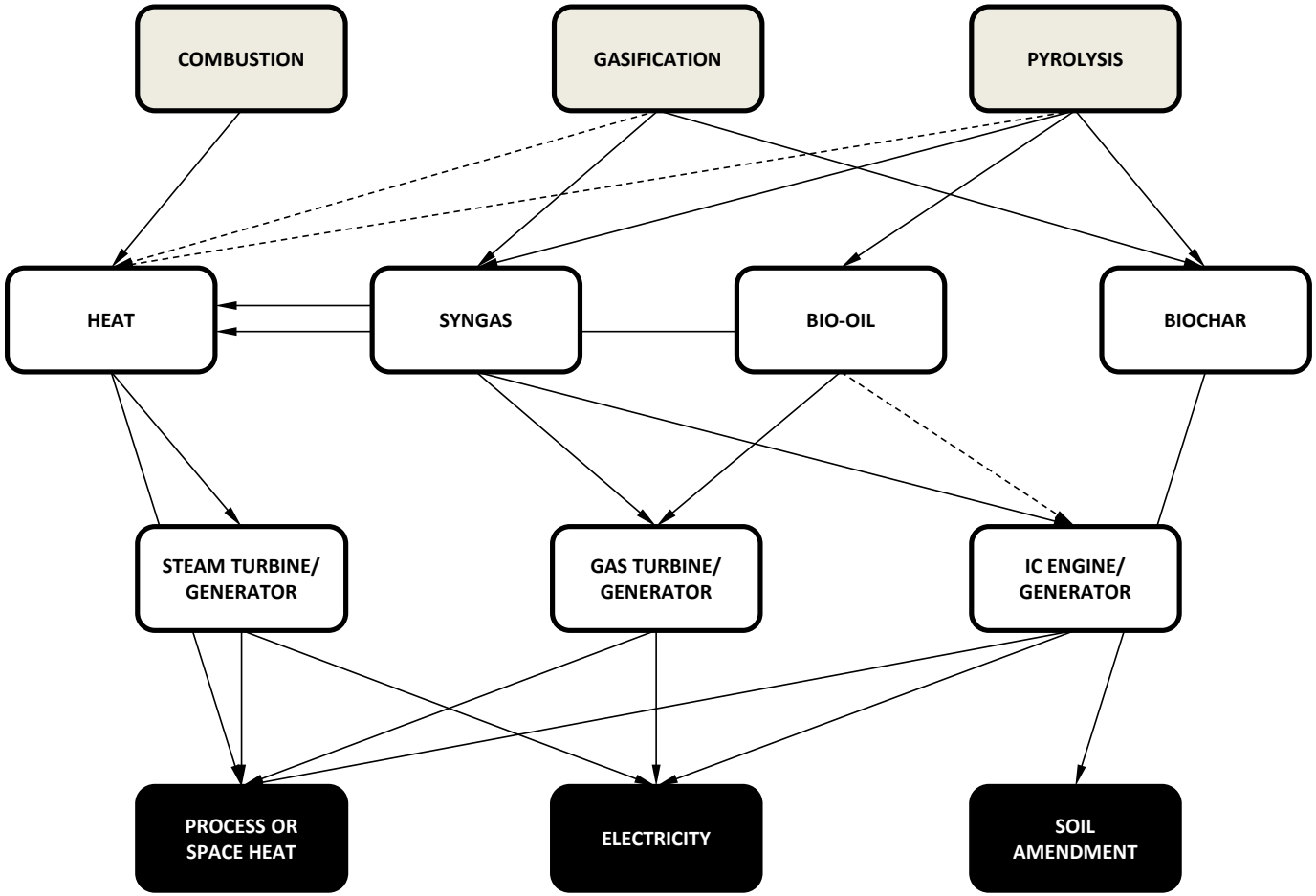

Figure 1. Biomass thermal conversion technology process streams[2]

[2] Dashed lines indicate indirect process steps. In the case of Gasification and Pyrolysis to Heat, waste heat is captured through use of a heat exchanger; for Bio-Oil to IC Engine/Generator, a secondary process is used to produce a drop-in biofuel. Figure adapted from an unknown online source.

These criteria attempt to balance the essential concerns of the water agency by addressing a range of technical and implementation factors that must be considered when selecting a preferred design for a bioenergy system. The first four criteria are listed in order of their relative priority as expressed by SCWA, with the lifecycle cost criterion serving only as an initial screening tool to eliminate alternatives that were disproportionately more expensive than the others. More detailed estimates of costs and monetized benefits of the preferred alternative are provided in Section 5 of this report.

1. Minimize Air Pollutant Emissions

This criterion is based primarily on the agency's goal of delivering "carbon free water" to its customers by 2015. The *CO2 emissions* produced by a given bioenergy system will be a function of both the technology employed (combustion, pyrolysis, or gasification) and the specific type of feedstock used. For example, woody biomass (e.g., tree trimmings) has a roughly 10% greater carbon content than agricultural residues (e.g., grape vines), which can be significant in terms of the carbon footprint of a bioenergy system over its lifecycle (Oak Ridge National Laboratory, 2011).

In addition to CO2 emissions, several other so-called *criteria air pollutants* as defined by the U.S. Environmental Protection Agency (EPA) were considered under this criterion. These included nitrogen oxides (NOx), sulfur dioxide (SO2), PM, and CO. The relative emissions of these pollutants by different bioenergy technologies must be examined to ensure that other important dimensions of air quality are not sacrificed solely for the sake of reduced carbon dioxide emissions.

2. Maximize Energy Efficiency

Different bioenergy generation technologies operate at different efficiencies. Therefore, it is necessary to examine a system's overall efficiency when comparing technologies in order to maximize the productive use of the energy content of the biomass feedstocks, which for practical purposes can be considered a finite resource. For this assessment, electric *power generation efficiency* was of primary concern, since electricity is the commodity that SCWA seeks to produce; however, consideration also was given to *thermal efficiency* because the

water agency may be able to offset some of the energy it consumes for heating and cooling through the use of a combined heat and power (CHP) system.

In addition, trade-offs exist between the type of feedstock used and the quantity of energy produced, and this also was considered in the analysis. Each type of biomass feedstock will have a unique energy content (e.g., 10-17 gigajoules [GJ] per metric ton [t] for agricultural residues) depending upon both its specific chemical composition and its moisture content. As a result, additional energy may be required to dry some feedstocks prior to their use in a gasification or pyrolysis unit, which would reduce the overall conversion efficiency of the system. Also, feedstocks produced at greater distances from the site of a bioenergy system require longer hauling distances, and the energy needed for that transport will offset some of the energy generated, thus reducing the net system output.

3. Maximize Feedstock Availability

This criterion was used to evaluate two key dimensions related to the availability of green waste feedstock sources. First, the *total amount* of feedstock available on an annual basis from green waste producers within Sonoma County was considered. This evaluation was based on an initial target design capacity for the bioenergy system of 1.0 MW of electricity (MWe) specified by SCWA, that is, whether sufficient local feedstock sources are available in aggregate to supply a bioenergy system of that size. Second, the assessment examined whether that supply is generated on a *consistent basis*, or whether it is likely to experience significant variations in its availability (e.g., due to seasonal fluctuations). Like the lifecycle cost criterion discussed later in this section, this was more of a screening device in that it represents a "go/no-go" decision for the agency since no further evaluation is warranted for any bioenergy systems that cannot be reliably supplied by locally-sourced feedstocks. Inherent in this evaluation is the flexibility of a given bioenergy system to utilize different feedstocks, either simultaneously or with periodic system modifications for fuel switching, which increases the likelihood of maintaining feedstock supplies year-round in sufficient quantities to fuel a bioenergy system of the minimum threshold size.

4. Maximize System Modularity

Because the anticipated sources of green waste are dispersed throughout Sonoma County, it may be advantageous for the bioenergy system to be *portable*. This could eliminate some of the logistical issues associated with feedstock procurement (e.g., densification, hauling, storage) by allowing the system to be moved to different locations in the county depending upon the availability of different feedstocks. For systems that are not portable, SCWA likely would need to perform additional feedstock management activities (e.g., bailing, grinding, drying) or contract those services out to another entity, which would determine some of the costs associated with operating the bioenergy system. It also may be beneficial for the system to be *scalable* so that multiple smaller units could be combined to develop a larger generating capacity if the water agency experiences increased demand for electricity in the future and additional feedstocks are available to meet that demand. In consultations with agency staff, it was determined that a bioenergy system that is both portable and scalable would be ideal, but not absolutely necessary.

5. Minimize Lifecycle Cost

As indicated previously, this criterion was applied solely to screen out any alternatives that appeared to be either prohibitively expensive for the water agency or substantially more costly than the others being considered. A much more rigorous benefit-cost analysis was used to evaluate the chosen alternative later in the feasibility assessment. Consequently, this criterion examined cost only at a gross level based on published system specifications and vendor quotes, when available. Two primary categories of costs were evaluated. The first, *capital costs*, relates to the up-front expenditures the agency would incur to acquire a bioenergy system. These might include purchasing (or leasing) equipment, preparing a site for equipment installation, and upgrading existing electrical grid interconnections to allow energy export and net energy metering of the new assets. The second category, *operations and maintenance (O&M) costs*, includes activities such as routine equipment maintenance, periodic system overhaul and/or repair, and feedstock procurement costs. Again, for this portion of the analysis, costs generally were estimated to a rough order of magnitude, and in some cases only qualitative assessments were made.

IV. EVALUATION OF ALTERNATIVES

Each of the three bioenergy alternatives was evaluated against the five criteria described above in order to select a preferred alternative for a more detailed analysis of its estimated costs and benefits. The evaluation was conducted in an iterative fashion, with increasing levels of definition being produced until one alternative emerged as being preferable to the other two based on the specific goals established by the water agency. That is not to imply that the preferred alternative was superior to the other two in every facet of its projected performance, but rather that the chosen alternative was judged to provide the best overall balance in terms of meeting the diverse objectives targeted by the evaluation criteria.

A. Projected Performance

Feasibility assessments of this type often require that assumptions be made regarding the anticipated performance of a given alternative, as was the case here. While published data on the air pollutant emissions and energy efficiency of the three alternative technologies were available, other performance characteristics were less well-established and therefore demanded more subjective evaluations based on limited information. For the feedstock availability criterion, attempts were made to collect new data for the water agency using a survey specific to Sonoma County. In other cases, particularly for the lifecycle cost of each technology, which can vary significantly depending on system size, generalizations were made based on limited sample sizes but with the understanding that costs would be more thoroughly examined in the subsequent benefit-cost analysis.

1. Air Pollutant Emissions

The three alternative technologies produce very different emissions across the range of air pollutants considered. Because pyrolytic processes are used to produce bio-oil (along with syngas) that is then either combusted directly or used in a secondary gasification process, no emissions profile was available for pyrolysis per se. Rather, air pollutant emissions for heating oil combustion were used as a proxy for bio-oil combustion emissions which, based on the limited data available, appears to be a reasonable approximation (AEA Technology, 2012). Specific deviations from the emissions profile for heating oil are addressed below.

CO2 emissions from biomass gasification and combustion, along with CO2 emissions from combustion of the primary fossil fuels used to generate electricity, are shown in Table 1A (see page 17). Each column in the table includes a comparison to the CO2 emissions of the current PG&E power mix, both in absolute terms (measured in pounds per megawatt-hour [lb/MWh]) and as a percentage difference. Similar comparisons are shown in Table 1B for the four criteria pollutants of concern as well as for VOCs.

Table 1A shows that, as is often cited in discussions of global warming and climate change, natural gas combustion emits less CO2 than oil, coal, or biomass combustion. What may be surprising, however, is that biomass gasification emits significantly more CO2 than biomass combustion (or combustion of fossil fuels) on a per MWh basis. This is due primarily to the fact that the syngas produced during biomass gasification has a much lower heating value than either solid biomass or fossil fuels, including natural gas. Syngas commonly has an energy density that is one-fourth that of solid biomass (Dion, 2011) and one-eighth that of natural gas (Sadaka, 2009). Its lower energy density requires that more syngas be used to generate each MWh of electricity, and thus more CO2 is emitted per unit of energy output.

It is also important to highlight the distinction made in Table 1A between fossil-based and biogenic CO2 emissions. Fossil fuels sequester carbon in solid, liquid, and gaseous forms for millions of years before being consumed, while biomass removes carbon dioxide from the atmosphere during its growth cycle and then releases it back into the atmosphere when it is consumed as fuel. Biomass therefore is generally considered to be a "carbon neutral" fuel, although that assertion discounts the temporal dimension of carbon dioxide capture and release, which could have short-range implications for global warming irrespective of whether there is no net addition of CO2 to the atmosphere. In the case being investigated here, however, it can be assumed that the use of *residual* biomass would in fact be carbon neutral, since any feedstocks used by the water agency in a bioenergy system likely would have been disposed of as green waste either in a landfill or by mulching, and consequently would have emitted CO2 (and CH4) during anaerobic decay. As a result, the biogenic CO2 emissions in Table 1A are fundamentally different than those from fossil sources and thus are addressed separately in this analysis. Except for natural gas, and without considering

the lifecycle implications of using fossil versus biogenic fuels discussed above, all of the fuels listed in Table 1A have higher CO2 emissions than the current PG&E power mix.

Performance with regard to emissions of criteria pollutants is much more variable across the different feedstocks, as indicated in Table 1B. Other than for SO2, biomass combustion generally fares poorly compared with biomass gasification and fossil fuel combustion (the exception being coal, which exhibits the highest emissions levels for nearly all pollutants considered). Using the emissions profile for oil combustion to estimate the air pollutant emissions that would be expected for bio-oil from pyrolysis, the figures in Table 1B show that its direct combustion would yield pollutant levels generally similar to those of natural gas and the current PG&E power mix, performing better than the latter in terms of CO and VOCs but markedly worse for SO2. An assessment of the combustion properties of bio-oil conducted in the United Kingdom suggests that it would likely produce somewhat higher emissions of CO and PM than the combustion of conventional heating oil. Therefore, the relatively better performance of pyrolysis oil over natural gas implied by the CO emissions shown in Table 1B may be overstated (AEA Technology, 2012).

Biomass gasification produces the lowest PM emissions of all the fuels shown in Table 1B, including the current PG&E power mix. Other emissions levels are higher than for natural gas but generally within the range produced by the PG&E power mix (i.e., within roughly 200-300% of average PG&E emissions, versus emissions that in some cases are orders of magnitude higher for coal and biomass combustion). Gasification therefore could offer a viable alternative in terms of criteria pollutant emissions, provided that state and federal emissions limits are met. Factoring in the biogenic nature of its CO2 emissions compared with those from natural gas combustion—the only fossil fuel having lower CO2 emissions than the current PG&E power mix—biomass gasification seems to provide the best overall air emissions performance of the three bioenergy alternatives under consideration. Again, it is important to note that all emissions in Table 1A and Table 1B have been normalized to units of lb/MWh so that each represents a quantity emitted *per unit of electricity generated* and thus allows for "apples to apples" comparisons of projected performance across the different bioenergy technologies.

Table 1A. Carbon dioxide emissions compared with the current PG&E power mix[1]

	PG&E Power Mix	Biomass Gasification	Compared to PG&E Power Mix		Biomass Combustion	Compared to PG&E Power Mix		Coal Combustion	Compared to PG&E Power Mix		Oil Combustion	Compared to PG&E Power Mix		Natural Gas Combustion	Compared to PG&E Power Mix	
	lb/MWh	*lb/MWh*	*lb/MWh*	*%*	*lb/MWh*	*lb/MWh*	*%*	*lb/MWh*	*lb/MWh*	*%*	*lb/MWh*	*lb/MWh*	*%*	*lb/MWh*	*lb/MWh*	*%*
Biogenic	-	2,950[2]	-	-	706	-	-	0	-	-	0	-	-	0	-	-
Fossil	-	0	-	-	0	-	-	719	-	-	550	-	-	399	-	-
Total	**412**	**2,950**	+2,538	**616%**	**706**	+294	**71%**	**719**	+307	**74%**	**550**	+138	**34%**	**399**	-13	**-3%**

[1]Carbon dioxide makes up more than 99% of GHG emissions (CO2e) from stationary sources including electricity generation (U.S. EPA, GHG Inventory Protocol Core Module Guidance, 2008)
[2]Independent calculations using raw test data yielded a value of ~2,930 lb/MWh; the higher value provided by the gasifier vendor (2,950 lb/MWh) was used as a conservative estimate

Note 1: PG&E emissions from California Public Utilities Commission GHG Calculator, Version 3c, October 2010 (2014 estimate)
Note 2: Biomass gasification emissions testing conducted by Airtech Environmental Services, Inc. on August 7, 2012
Note 3: Biomass combustion emissions data from The Climate Registry Default Emissions Factors, Table 12.1, January 2012
Note 4: Fossil fuel combustion emissions data from U.S. Energy Information Administration, Carbon Dioxide Emission Factors for Stationary Combustion, 2011
*Note 5: Negative values indicate carbon dioxide emissions that are **lower** than those produced by the current PG&E power mix*

Table 1B. Criteria pollutant emissions compared with the current PG&E power mix

	PG&E Power Mix	Biomass Gasification	Compared to PG&E Power Mix		Biomass Combustion	Compared to PG&E Power Mix		Coal Combustion	Compared to PG&E Power Mix		Oil Combustion	Compared to PG&E Power Mix		Natural Gas Combustion	Compared to PG&E Power Mix	
	lb/MWh	*lb/MWh*	*lb/MWh*	*%*	*lb/MWh*	*lb/MWh*	*%*	*lb/MWh*	*lb/MWh*	*%*	*lb/MWh*	*lb/MWh*	*%*	*lb/MWh*	*lb/MWh*	*%*
PM	1.04E-01	5.47E-03	-9.87E-02	**-95%**	1.04E+00	9.36E-01	**899%**	4.78E+00	4.67E+00	**4480%**	1.88E-01	8.38E-02	**80%**	2.39E-02	-8.03E-02	**-77%**
CO	1.87E-01	5.47E-01	3.59E-01	**192%**	2.05E+00	1.86E+00	**992%**	1.23E+00	1.04E+00	**555%**	1.34E-01	-5.32E-02	**-28%**	2.05E-01	1.72E-02	**9%**
NOx	3.20E-01	1.33E+00	1.01E+00	**315%**	1.19E+00	8.74E-01	**273%**	2.39E+00	2.07E+00	**646%**	5.37E-01	2.17E-01	**68%**	5.63E-01	2.43E-01	**76%**
SO2	9.63E-02	1.67E-01	7.10E-02	**74%**	6.82E-02	-2.81E-02	**-29%**	4.44E+00	4.34E+00	**4506%**	4.03E+00	3.93E+00	**4080%**	1.71E-03	-9.46E-02	**-98%**
VOC[1]	1.11E-02	3.46E-02	2.35E-02	**212%**	6.82E-02	5.71E-02	**515%**	8.53E-02	7.42E-02	**669%**	9.13E-03	-1.97E-03	**-18%**	1.71E-02	5.96E-03	**54%**

[1]Not a regulated "criteria pollutant" in non-industrial settings; THC emissions used as a proxy for VOC emissions from biomass gasification, consistent with U.S. EPA guidelines (i.e., within +/- 7%)

Note 1: PG&E emissions estimates based on proportions of various fossil and non-fossil fuels in the utility's 2010 power mix, with "unspecified sources" assumed to be natural gas
Note 2: Biomass gasification emissions testing conducted by Airtech Environmental Services, Inc. on August 7, 2012
Note 3: Combustion emissions data (except oil) from Mayhead and Shelly, Woody Biomass Factsheet - WB3: Electricity from Woody Biomass, University of California, Berkeley, May 2012
Note 4: Oil combustion emissions data for Number 4 heating oil from AP-42: Compilation of Air Pollutant Emission Factors, U.S. Environmental Protection Agency, January 1995
*Note 5: Negative values indicate criteria pollutant emissions that are **lower** than those produced by the current PG&E power mix*

2. Energy Efficiency

The energy content of a biomass feedstock used to generate power ultimately is converted into one of three end products: electricity, useful heat, or waste heat. The proportion of feedstock energy that is converted into electricity is the power generation efficiency of the bioenergy system. This, combined with the portion of the energy content converted into heat used for purposes other than generating electricity (e.g., to supply a building heating, ventilation, and air conditioning [HVAC] system, for feedstock drying), is the total thermal efficiency of the system. The balance of the initial energy content of the biomass feedstock not converted into electricity or useful heat either is lost as waste heat during the thermal conversion process or remains within any incompletely consumed biomass materials such as ash or biochar.

The power generation and thermal efficiencies of a combustion, pyrolysis, or gasification system will vary depending upon the particular configuration used (e.g., downdraft versus fluidized bed), the operating parameters of the system (e.g., size, average capacity factor), and the characteristics of the feedstock being consumed, among other factors. Therefore, performance relative to the energy efficiency criterion is best evaluated using ranges. For biomass combustion, power generation efficiencies of 30-35% and thermal efficiencies of 85-90% could be expected from newer, well-tuned CHP systems using dry woody biomass feedstocks (International Energy Agency, 2007). Biomass pyrolysis systems, which employ relatively novel technologies and thus have less well-established performance histories, have achieved power generation efficiencies of 33-36% (Envergent Technologies, 2010) and total thermal efficiencies of up to 82% (Lemieux, Roy, de Caumia, & Blanchette, 1987). Finally, biomass gasification systems, which have been utilized extensively in Europe for combined heat and power applications, offer power generation efficiencies ranging from 23-40% and thermal efficiencies of 60-88% (International Energy Agency, 2006). Based on these values, it can be safely projected that a biomass gasification system could produce electricity at least—if not more—efficiently than either biomass combustion or pyrolysis, and could nearly match the thermal efficiency possible with biomass combustion. Thus gasification is able to make the most productive use of finite biomass feedstock sources.

3. Feedstock Availability

To assess whether or not an adequate supply of green waste could be available from within Sonoma County to fuel a bioenergy system, a written survey was developed and sent as a direct request from SCWA to a dozen representatives of regional green waste producers including wineries, vineyards, landscaping services, and nearby municipalities. A member of the water agency staff also completed a survey based on the residual biomass that SCWA produces from its routine watershed maintenance activities (e.g., cutting trees, shrubs, and vines within flood control channels). The surveys were distributed in two rounds, the first in January 2012 and the second in June 2012. Including the survey completed by the water agency, a total of three responses were received. The difficulties encountered in collecting survey data on the availability of biomass sources within Sonoma County led to a focus on the green waste produced by the water agency itself, which was found to be substantial (about 10,500 cubic yards [yd^3] annually). Based on preliminary calculations of how much feedstock would be needed to supply a 1.0 MWe bioenergy system, it was determined that the agency could not supply a system that large using solely its own green waste, but that a pilot-scale system on the order of 100-250 kilowatts electrical (kWe) could be feasible. It also seemed, based on the sparse survey data received, that the agency could partner with several other local green waste producers to obtain sufficient biomass feedstocks to fuel a utility-scale bioenergy system (i.e., one with a nameplate capacity of at least 1.0 MWe).[3] Nevertheless, from that point forward, the analysis was limited to assessing the feasibility of implementing a <u>pilot-scale</u> bioenergy system using only the feedstock produced by the water agency. A copy of the completed biomass survey from SCWA, along with a template of the cover letter distributed to all prospective respondents, is provided in Appendix A.

Because evaluation of the feedstock availability criterion was restricted to the green waste produced by the water agency, there were no differences in the total amount of feedstock available on an annual basis: all three bioenergy alternatives would be able to use all the organic material SCWA generates from watershed maintenance activities, which currently

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[3] For example, one local tree services company reported that it produces more than 4,000 yd^3 of green waste annually at its Santa Rosa location.

is ground into wood chips that are either mulched or composted. Similarly, all three would face the same seasonality constraints, since nearly 90% of the agency's residual biomass is generated between June and October each year.[4] There are, however, notable differences in the flexibility of feedstocks that can be accommodated by the three thermal conversion technologies. Combustion offers the most flexible means of biomass conversion, allowing for a wide range of organic materials of various sizes, forms, moisture contents, and levels of impurities. Pyrolysis, on the other hand, requires the most tightly controlled feedstock specifications, since the utility of the bio-oil produced depends directly upon the qualities of the feedstock used (U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, 2012). Gasification generally falls between the other two technologies. Gasifier performance is typically maximized when feedstocks have a moisture content of around 10-15%, although higher moisture contents can be tolerated with some sacrifice in overall thermal conversion efficiency (National Energy Technology Laboratory, 2002).

4. System Modularity

Modular biomass combustion units are readily available in a range of sizes; however, most are limited to use in dedicated heating systems. For combined heat and power systems, there are presently only a handful of technology options either commercially available or under development, including systems based on 1) an open Brayton cycle using hot air to drive a gas turbine, and 2) an organic Rankine cycle using vaporized fluid to drive a vapor turbine (National Renewable Energy Laboratory, 2009). These direct combustion systems range in size from 300 kWe to 1.5 MWe. Of the systems currently in use, none has been fielded at more than a single site, so the issue of scalability has not yet been addressed by system developers or vendors.

Several mobile biomass pyrolysis demonstration units currently are being developed and tested by technology vendors as well as through collaborative research efforts by various government agencies and universities in the U.S. and Canada (Coleman, 2009), but to date

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[4] It can be assumed based on this seasonal variation that all three bioenergy systems would require some type of feedstock storage; therefore, this factor cannot be used to differentiate among the three alternative technologies and thus was not considered in this assessment.

it does not appear that any of the systems are commercially available for near-term use in woody biomass conversion. In addition, some of these "mobile" demonstration units are much larger than originally envisioned by the water agency (e.g., requiring four rail cars or six flatbed trucks to be moved from one location to another) and consequently do not offer the advantage of easy mobility. Scalability is likewise not yet practical given the evolving technology variants for portable biomass pyrolysis.

There are at least a dozen vendors of small- to medium-scale biomass gasification systems in the U.S. and Canada (National Renewable Energy Laboratory, 2009), with some offering modular CHP systems for sale or lease. Units range in size from 5 kWe to 5 MWe and utilize either 1) a close-coupled system in which syngas is combusted directly in a boiler to drive a steam turbine, or 2) a two-stage system in which the syngas is cleaned and then combusted in a gas turbine or an internal combustion engine linked directly to an electric generator (i.e., a genset). Some modular gasification units are designed to be fully mobile (e.g., skid-mounted or containerized) and at least one vendor has designed units having the capability to be banked into groups of up to five 100 kWe units, allowing for scalability should energy demand increase. This combination of portability and scalability gives biomass gasification technologies a distinct performance advantage over pyrolysis and combustion as measured by the system modularity criterion.

5. Lifecycle Cost

A report published by the U.S. EPA Combined Heat and Power Partnership (2008) included a summary of typical cost and performance characteristics for various CHP technologies. It found unit capital costs for direct combustion systems (for both biomass and fossil fuels) in the range of $0.43 to $3.00 per watt (W) of installed electrical capacity. Costs varied based on the system size (larger systems afforded lower unit costs) and the specific conversion technology used (e.g., steam turbine, reciprocating engine), with microturbines sized from 30 kWe to 250 kWe exhibiting the highest unit capital costs. A more recent assessment by researchers at the University of California, Berkeley found unit capital costs for utility-scale biomass power plants of $2.00 (for a 40 MWe plant) to $3.50 (for a 5 MWe plant) per watt of installed capacity (Mayhead & Shelly, 2012). A modular biomass combustion system of

the scale being considered for the SCWA pilot project most likely would have a unit capital cost at or above those of the larger systems listed above.

Given the relative immaturity of the still-emerging market for modular biomass pyrolysis power generation systems, capital costs for this technology are less readily available than those for biomass combustion and gasification. Most reported costs for biomass pyrolysis are given in dollars per quantity of biomass feedstock consumed, with one recent report estimating a bare equipment cost of more than $12,000 per metric ton per day (tpd) and a total installed system cost of approximately $30,000/tpd excluding heat recovery, power generation, and utilities. Adding those components to the capital cost estimate and using a rough conversion factor of 142 kWh of electricity generated from direct bio-oil combustion per metric ton of biomass feedstock consumed produces a unit capital cost for a biomass pyrolysis system of about $8.03 per watt of installed capacity (Pacific Northwest National Laboratory, 2009).[5] Because this cost estimate was developed for a utility-scale pyrolysis system on the order of 10 MW, it is likely that the unit capital cost for a modular pyrolysis system would be higher due to the loss of economies of scale.

Biomass gasification has been used extensively for combined heat and power applications in Europe and, to a lesser extent, in Asia. Consequently, more robust capital cost data are available for this technology than for biomass combustion (which is used more commonly in heating applications without also generating electricity) or biomass pyrolysis, especially at modular scales. A report presented at a bioenergy workshop held by the International Energy Agency (IEA) showed that biomass gasification systems incur capital costs ranging from $3.69 to $6.64 per watt of installed electrical capacity, with an average unit cost of $4.61/W (International Energy Agency, 2006). Rough price estimates obtained from two domestic modular gasifier vendors yielded unit costs of $1.35/W for a manually operated, stand-alone 20 kWe unit up to $12.00/W for a fully automated, grid-connected 100 kWe gasification system. These price estimates are generally consistent with the cost data from

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[5] The unit cost calculation is based on an average power of 142 kWh per metric ton of biomass feedstock for five projects included in a 2009 literature review, and an installed capital cost estimate of $95.5 million for a utility-scale pyrolysis oil power generation system. Appendix B provides a more detailed explanation of the $8.03/watt unit capital cost calculation.

the IEA report, and indicate that advances in gasification technologies may be overcoming the losses in economies of scale still evident in pyrolysis and combustion power generation systems. Appendix C provides average and project-specific conversion efficiency and cost data from existing biomass gasification systems as reported by IEA.

In addition to the capital costs characterized above, operations and maintenance activities also would result in considerable costs for all three bioenergy alternatives. Some of those O&M costs would be more or less equivalent across technologies (e.g., feedstock storage, system monitoring), while others could vary considerably based on system complexity. A direct biomass combustion system, for example, would be less sensitive to variations in the feedstock moisture content or impurities compared with pyrolysis or gasification. Without undertaking a detailed assessment of the operating costs for each technology at this point, it generally can be assumed that a pyrolysis system would incur the highest O&M costs per unit of electricity produced given its inherent complexity and tightly controlled operating parameters (i.e., thermochemical decomposition in a vacuum). Conversely, a combustion system likely would incur the lowest O&M costs due to its relative technological simplicity, with a gasification system falling somewhere between the other two technologies.[6]

B. Comparative Assessment

A summary of the projected performance of the three bioenergy alternatives across each of the five evaluation criteria is provided in Table 2. In most cases, quantitative data allow for direct comparisons of performance among the alternatives. As outlined earlier, differences in feedstock availability for the three technologies are more qualitative in nature and stem from the varying flexibility in feedstock moisture content, impurities, and form factors that can be accommodated by each thermal conversion technology. Directly following the table is a synthesis of the performance strengths and weaknesses of each bioenergy alternative, with the rationale for selecting the single most promising alternative for further evaluation via benefit-cost analysis provided in the succeeding section of the report.

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[6] The cost of the feedstock itself was not considered an additional O&M cost since it is a byproduct of the water agency's normal operations. Likewise, feedstock transport to a generating facility likely would be comparable to current hauling to disposal sites, and thus was not considered an additional O&M cost.

Table 2. Summary of projected performance for the three bioenergy alternatives[7]

Evaluation Criteria	Alternative 1 *Combustion*	Alternative 2 *Pyrolysis*	Alternative 3 *Gasification*
Minimize Air Pollutant Emissions	706 lb/MWh CO2 Very High PM, CO, VOC Low SO2	550 lb/MWh CO2 Very High SO2 Low CO, VOC	2,950 lb/MWh CO2 High NOx Very Low PM
Maximize Energy Efficiency	Generation: 30-35% Thermal: 85-90%	Generation: 33-36% Thermal: <=82%	Generation: 23-40% Thermal: 60-88%
Maximize Feedstock Availability	Most Flexible Feedstock Parameters	Least Flexible Feedstock Parameters	Moderately Flexible Feedstock Parameters
Maximize System Modularity	Very Limited CHP Options	Not Commercially Available	Multiple Domestic Vendors
Minimize Lifecycle Cost	$0.43-$3.50 per watt Lowest O&M costs	$8.03 per watt Highest O&M costs	$1.35-$12.00 per watt Moderate O&M costs

1. Combustion

Direct biomass combustion offers several advantages relative to pyrolysis and gasification, including the following:

- Low SO2 emissions;
- High thermal efficiency;
- High feedstock flexibility;
- Low unit capital costs; and
- Low O&M costs.

These advantages are offset by two significant challenges, however, that make combustion a difficult proposition for the water agency: 1) very high PM, CO, and VOC emissions levels, and 2) an extremely limited number of commercially available modular CHP systems.

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[7] Qualitative descriptors for criteria pollutant emissions are based on their percentage differences (listed in Table 1B) relative to the current PG&E power mix, as follows: Very Low = -50% or less, Low = -49% to -1%, High = 300% to 499%, Very High = 500% or more.

2. Pyrolysis

In contrast to combustion, biomass pyrolysis offers some desirable environmental benefits, notably its relatively low CO2 emissions (comparable to the current PG&E power mix) as well as lower CO and VOC emissions. Unfortunately, this technology poses obstacles that together would be very difficult for the water agency to overcome, including the following:

- Very high SO2 emissions;
- Low feedstock flexibility;
- No commercially available modular systems;
- High unit capital costs; and
- High O&M costs.

3. Gasification

Biomass gasification provides several important advantages over the other two bioenergy technologies; however, it also presents some drawbacks. On the positive side, gasification possesses the following characteristics:

- Very low PM emissions;
- High power generation efficiency;
- Moderate feedstock flexibility;
- Multiple domestic vendors of modular systems;
- Low to moderate unit capital costs; and
- Moderate O&M costs.

These positive qualities are counterbalanced by its relatively high NOx emissions—about three times those of the current PG&E power mix—and its very high CO2 emissions versus both the PG&E power mix and the other two thermal conversion technologies. This latter issue, however, is mitigated by the fact that the CO2 emissions are from biogenic sources and hence are the product of a carbon neutral fuel cycle (as are the CO2 emissions from the other two alternatives). The current PG&E power mix, on the other hand, relies heavily on natural gas and to a lesser degree on other fossil fuels, the combustion of which results in a net addition of carbon to the atmosphere.

C. Selected Alternative

Given the numerous environmental, technical, logistical, and economic trade-offs inherent in the three bioenergy technologies included in this assessment, ***gasification is presently the best alternative*** for the water agency based on overall performance versus risk across the five evaluation criteria. Biomass gasification is a carbon neutral energy source having relatively low criteria pollutant emissions (other than for NOx, which is addressed in more detail in the later benefit-cost analysis), high power generation efficiency, low to moderate capital and O&M costs, and a range of commercially available modular systems that can use the organic waste produced by the agency's stream maintenance activities as a feedstock to generate electricity, partially offsetting retail power purchases and possibly creating a new revenue stream. Although biomass pyrolysis could offer additional environmental benefits over gasification, the technology remains under development at a modular scale and thus poses greater cost and schedule risk to the water agency as it looks to acquire additional renewable electricity generation assets in the near term. Biomass combustion, on the other hand, produces unacceptably high levels of air pollutant emissions and has yet to be widely fielded in modular CHP applications.

Among the growing number of domestic vendors of modular biomass gasification systems, Community Power Corporation (CPC) of Littleton, Colorado has worked with the U.S. DOE National Renewable Energy Laboratory (NREL) for more than a decade to design and build automated, mobile gasifiers of the type and scale currently being contemplated by SCWA. During the course of this feasibility assessment, CPC offered valuable explanations of the various elements of the gasification process, access to their testing and production facility, and historical cost and performance data that directly informed the benefit-cost analysis that follows. Although use of the CPC gasifier as a baseline for the detailed cost and benefit calculations in this report does not constitute an endorsement of CPC as a preferred vendor for the water agency in its potential acquisition of bioenergy generation assets, it should be viewed as a viable procurement option based on the maturity of both the firm itself and its system design relative to others currently on the market. Any specific recommendations of this nature, however, are contingent upon the results of the ensuing benefit-cost analysis.

A site visit to the CPC offices and fabrication shop in October 2012 yielded detailed system specifications, emissions reports, and cost estimates that were essential in developing the more rigorous benefit-cost analysis presented in Section 5. CPC's current flagship product, the BioMax 100, is a 100 kWe biomass gasification system housed in five 20-foot shipping containers having a combined footprint of 900 square feet. It generates electricity and heat for CHP applications, and is a fully automated system designed to operate continuously for up to 30 days between scheduled maintenance outages. The system can produce 350,000 Btu/hr of heat along with nearly 2.0 MWh of electricity in a 24-hour period (assuming an average availability of approximately 80%). It does so by fueling two internal combustion engines with syngas, which in turn drive an electric generator. The BioMax 100 either can be operated as a stand-alone unit or banked into groups of five for a nameplate capacity of up to 500 kWe. The system also complies with grid interconnection requirements for use in a net energy metering scenario. Figures 2 through 4 below show the configuration of the BioMax 100 system and details of its gasifier and genset components. Appendix D provides additional system specifications and other data collected during the site visit to CPC.

Figure 2. Modular configuration of the BioMax 100 gasification system

Figure 3. Downdraft gasifier used in the BioMax 100

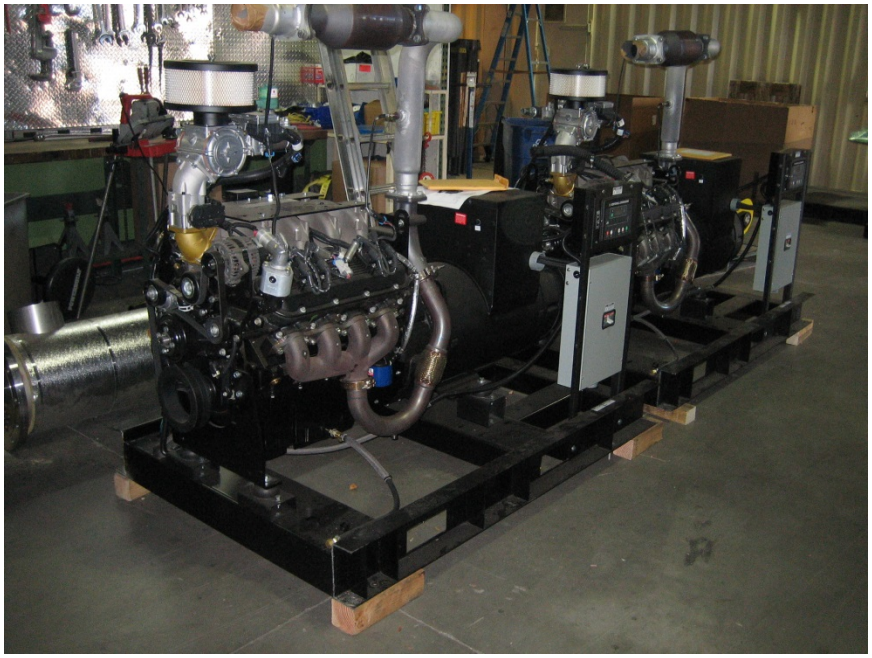

Figure 4. Internal combustion engine-generators used in the BioMax 100

V. BENEFIT-COST ANALYSIS

The following benefit-cost analysis (BCA) was conducted within the bounds often used to define *sustainability*, that is, giving explicit consideration to the three elements of people, planet, and profit. These elements are referred to in this report as *social*, *environmental*, and *economic* benefits and costs, and are detailed below as well as in Appendices E and F. It is important to note that all costs and benefits were evaluated with respect to the water agency as a public entity and the residents of Sonoma and Marin counties it serves. As a result, the BCA model presented here is not designed to capture the full range of costs and benefits that could be relevant within a different context (e.g., statewide or globally).

Calculation of the net benefit of a modular biomass gasification system in terms of its net present value (NPV) is followed by a sensitivity analysis that assesses the confidence with which the BCA results can be utilized by the water agency in its strategic decision making. Again, the use of the BioMax 100 system produced by Community Power Corporation as a baseline for this BCA is intended to demonstrate the tangible benefits and costs that could be expected from acquiring a pilot-scale modular biomass gasification system. It is not an endorsement of a specific vendor, but rather a means of making the analysis more directly quantifiable and thus more concrete. That being said, the BioMax 100 does appear to be a viable option that warrants further consideration by SCWA going forward.

A. Estimated Benefits

As noted above, the benefits offered by a biomass gasification system can be categorized as social, environmental, and economic. Each type of benefit is described and, in most cases, quantified below. Note that these are *gross* benefits, and that the costs of implementing a bioenergy system would reduce the *net* benefit ultimately realized by the water agency, as discussed in subsequent sections of the BCA.

1. Social Benefits

The primary social benefit offered by a biomass gasification system is the ability of SCWA as a public agency to demonstrate its continuing commitment to sustainability and to lead by example in its pursuit of the goal to deliver carbon free water by 2015. The agency has

established itself as a progressive organization in terms of reducing its carbon footprint and securing the long-term viability of its fresh water delivery and wastewater treatment systems, and the acquisition of a self-sustaining bioenergy system would further bolster that reputation. Due to its relatively small size, a pilot-scale system could be operated by existing SCWA staff; however, if the pilot system yielded the expected benefits, it could be replicated elsewhere in the county and/or increased in size to utility-scale at a single site, possibly creating new jobs for Sonoma County residents.

2. Environmental Benefits

There are two direct environmental benefits afforded by generating electricity (and heat) from biomass gasification: 1) replacing carbon emissions from fossil fuel combustion with biogenic CO2 emissions, and 2) reducing particulate matter (PM) emissions. Because the PM emissions from the current PG&E power mix are already less than 4% of the ambient limit established by the Bay Area Air Quality Management District (BAAQMD), the marginal benefit of any further reductions provided by biomass gasification was not considered in this BCA. Focus therefore was placed on the available net reduction in carbon emissions, which in addition to supporting the water agency's sustainability goals also could produce a monetary benefit in the form of tradable GHG emissions offsets. As noted previously, the higher CO2 emissions of biomass gasification relative to those of the current PG&E power mix are from a renewable, carbon neutral source, while PG&E continues to rely on fossil fuels (mainly natural gas) for roughly 40% of its power generation (Pacific Gas and Electric Company, 2013). Also, the CO2 emissions from a gasifier fueled by residual biomass occur in lieu of the carbon that would be emitted by the aerobic and/or anaerobic decomposition of that same organic material either in situ or through mulching or composting. This is a fundamental proposition of the benefit-cost analysis: ***CO2 emissions from generating electricity using biomass gasification would be offset by reductions in CO2 emissions from avoided decomposition of green waste being produced by the water agency.***

Quantifying the net reduction in CO2 emissions available through gasification of residual biomass requires an estimate of the amount of feedstock needed to power a gasifier. For a 1.0 MWe gasifier (chosen as a reference value that can be scaled up or down depending on

the needs of the water agency), Table 3 provides a detailed calculation of the volume of dry woody biomass of the type produced by SCWA stream maintenance activities that would be needed to fuel the gasifier for one year. This estimate assumes a system capacity factor of roughly 80%, a power generation efficiency of 27.6% (based on the data in Table C-1), and an energy density of 16 megajoules per kilogram (MJ/kg) of woody biomass. As shown in the table, approximately 37,200 cubic yards of feedstock would be required annually to fuel a 1.0 MWe gasifier.

Table 3. Volume of woody biomass feedstock required to fuel a 1.0 MWe gasifier

Value	Units	Calculation
1.00	MW	Assumed size of utility-scale gasification system
1,000	kW/MW	Conversion factor for MW to kW
1,000	kW	Nameplate capacity of gasification system
8,760	hr/yr	24 hr/day * 365 days/yr
8,760,000	kWh/yr	1,000 kW * 8,760 hr/yr
79.5	%	System capacity factor (approximate uptime)[1]
6,960,000	**kWh/yr**	**Approximate electricity output per year**
16.0	MJ/kg	Approximate energy density of air-dried wood chips[2]
0.278	kWh/MJ	Conversion factor for MJ to kWh
4.44	kWh/kg	16.0 MJ/kg * 0.278 kWh/MJ
1,570,000	kg/yr	6,960,000 kWh/yr / 4.44 kWh/kg
4,300	kg/day	1,570,000 kg/yr / 365 days/yr
1,000	kg/t	Conversion factor for kg to metric tons
4.30	t/day	Net mass of dry feedstock required per day
27.6	%	Percentage of energy content converted to electricity[3]
15.6	**t/day**	**Gross mass of dry feedstock required per day**
200	kg/m3	Approximate bulk density of dry wood chips[4]
1.69	lb/yd3 / kg/m3	Conversion factor for kg/m3 to lb/yd3
337	lb/yd3	200 kg/m3 * 1.69 lb/yd3 / kg/m3
0.153	t/yd3	337 lb/yd3 / 2,204.6 lb/t
102	yd3/day	15.6 t/day / 0.153 t/yd3
37,200	**yd3/yr**	**Volume of dry woody biomass feedstock required per year[5]**

[1]Reported system performance from domestic commercial gasifier vendor, January 2013
[2]Penn State Biomass Energy Center, Pennsylvania State University, 2010
[3]Reported system performance from IEA Thermal Gasification of Biomass Workshop, May 2006
[4]Harris and Phillips, Georgia Forestry Commission, February 1986
[5]SCWA produces approximately 10,500 yd3/yr of woody biomass from watershed maintenance

Note 1: Assume a 40' trailer can haul up to 20 tons or 80 cubic yards of green wood chips [4]
Note 2: 15.6 t/day @ 79.5% CF consistent with vendor estimate of ~2.0 tons per day for 100 kWe system

The next step in determining the net reduction in CO2 emissions from biomass gasification was the calculation of a *GHG emissions factor* for mulching woody biomass, which is one of the primary disposal routes currently used by SCWA for its green waste (see Appendix A). The calculation was based on an existing lifecycle assessment (LCA) of biomass emissions conducted by scientists at NREL (Mann & Spath, 2001). Table 4 shows the calculation of a GHG emissions factor of 3.07, meaning that for every kilogram of mulched woody biomass, the *equivalent* of 3.07 kilograms of carbon dioxide will be emitted. This estimate assumes that 90% of the mulched biomass will decompose aerobically, with the other 10% decaying anaerobically and producing a relatively small but potent quantity of methane. As noted at the bottom of the table, carbon dioxide makes up more than 99% of total GHGs emissions from electricity generation using fossil fuel combustion (U.S. EPA Climate Leaders, 2008). Consequently, the GHG emissions avoided by not mulching woody biomass that is used as gasifier feedstock are assumed to be equivalent (within +/- 1%) to the GHG emissions of the fossil fuels used by PG&E to generate electricity. Moreover, the GHG emissions factor in Table 4 has units of carbon dioxide equivalent (CO2e) and therefore is directly comparable to the CO2 emissions produced by biomass gasification and fossil fuel combustion.

Table 4. Greenhouse gas emissions factor for mulching woody biomass

Value	Units	Calculation
100	kg	Reference mass of bone dry woody biomass
167	kg	Mass of CO2 emitted through aerobic decomposition[1]
6.67	kg	Mass of CH4 emitted through anaerobic decomposition[1]
21	kg CO2/kg CH4	100-year global warming potential of CH4 relative to CO2[2]
140	kg	Equivalent mass of CO2 from CH4 emissions
307	kg	Total GHG emissions from mulching (CO2 equivalent)
3.07	**kg CO2e/kg**	**GHG emissions factor for mulching woody biomass**

[1]Mann and Spath, National Renewable Energy Laboratory, June 2001
[2]U.S. EPA climate change fact sheet on methane emissions, June 2012

Note 1: Biomass survey response indicates most SCWA biomass is mulched or composted (February 2012)
Note 2: CO2 constitutes >99% of total GHG emissions (CO2e) from electricity generation (U.S. EPA, 2008)

The net reduction in greenhouse gas emissions available to the water agency from using a 100 kWe biomass gasifier to generate electricity is calculated in four steps in Table 5A. The first step shows the CO2 emitted annually from a BioMax 100 (930 metric tons) based on

the 79.5% availability reported by CPC and the emissions test results provided by Airtech Environmental Services. Next, the total GHGs emitted annually from mulching all 10,500 cubic yards of residual woody biomass produced by SCWA (4,910 metric tons) is calculated using the GHG emissions factor derived in Table 4. Those GHG emissions are then reduced (to 1,740 metric tons) in proportion to the volume of the water agency's residual biomass that would be needed to fuel a 100 kWe gasifier. The third step uses the projected 2014 PG&E greenhouse gas emissions factor published by the CPUC to calculate the emissions avoided by replacing purchases of PG&E electricity with energy generated by the gasifier (130 metric tons). Finally, the annual net reduction in emissions is found by subtracting the quantity of CO2 emitted by the gasifier from the sum of the GHG emissions that would be avoided by reductions in both mulching and purchases of PG&E electricity (940 metric tons). ***This is a substantial reduction in emissions given that a total of approximately 750 metric tons of greenhouse gases were emitted from generating the electricity used by SCWA in 2011 for its water transmission and wastewater treatment operations.***

Further reductions in carbon emissions are available when the biomass gasifier is used in a CHP application. Of the three SCWA sites considered for potential installation of a 100 kWe biomass gasifier (discussed in greater detail in the economic benefits section that follows), the administration building at 404 Aviation Boulevard is the only one that consumes PG&E natural gas for heating, thus providing an opportunity for additional emissions offsets. As the calculation in Table 5B shows, an *additional* 61.2 metric tons of GHG emissions could be avoided by using a 100 kWe biomass gasifier in a combined heat and power scenario, for a total of just over one kiloton of reduced GHG emissions per year at that site.

The value of this net reduction in carbon emissions was monetized using results from the quarterly auction of GHG emissions allowances held by the California Air Resources Board (ARB) in August 2013 (see Table 6). The auction settlement price of $12.22 per metric ton was used to assess a *theoretical* monetary benefit for the water agency, assuming that all the offsets could be sold. It is critical to note that this price <u>does not</u> represent the marginal social benefit of reduced GHG emissions, but rather the financial gain that could be realized by Sonoma County as a byproduct of an inherently global environmental benefit.

Table 5A. Net reduction in GHG emissions from generating electricity

Value	Units	Calculation
696,000	kWh/yr	Approximate electricity output of 100 kWe gasifier[1]
1,000	kWh/MWh	Conversion factor for kWh to MWh
696	MWh/yr	696,000 kWh/yr / 1,000 kWh/MWh
2,950	lb/MWh	Carbon dioxide emissions from 100 kWe gasifier[2]
2,050,000	lb/yr	2,950 lb/MWh * 696 MWh/yr
0.454	kg/lb	Conversion factor for lb to kg
930,000	kg/yr	2,050,000 lb/yr * 0.454 kg/lb
1,000	kg/t	Conversion factor for kg to metric tons
930	**t/yr**	**Greenhouse gas emissions from 100 kWe biomass gasifier**
10,500	yd3/yr	Volume of residual woody biomass produced by SCWA[3]
560	lb/yd3	Approximate bulk density of green wood chips[4]
5,880,000	lb/yr	10,500 yd3/yr * 560 lb/yd3
0.454	kg/lb	Conversion factor for lb to kg
2,670,000	kg/yr	5,880,000 lb/yr * 0.454 kg/lb
1,000	kg/t	Conversion factor for kg to metric tons
2,670	t/yr	Mass of residual woody biomass produced by SCWA
0.60	t/t	Conversion factor for green to dry mass (40% moisture content)[4]
1,600	t/yr	2,670 t/yr * 0.60 t/t
3.07	t CO2e/t	GHG emissions factor[5]
4,910	t/yr	Greenhouse gas emissions from mulching SCWA biomass
3,720	yd3/yr	Volume of feedstock required per 100 kWe gasifier[6]
35.4	%	Proportion of total SCWA biomass produced per year
1,740	**t/yr**	**Avoided SCWA greenhouse gas emissions per gasifier**
696	MWh/yr	Avoided PG&E electricity consumption per 100 kWe gasifier
412	lb/MWh	PG&E greenhouse gas emissions factor[7]
287,000	lb/yr	696 MWh/yr * 412 lb/MWh
0.454	kg/lb	Conversion factor for lb to kg
130,000	kg/yr	287,000 lb/yr * 0.454 kg/lb
1,000	kg/t	Conversion factor for kg to metric tons
130	**t/yr**	**Avoided PG&E greenhouse gas emissions per gasifier**
1,870	t/yr	Total avoided greenhouse gas emissions per gasifier
940	**t/yr**	**Net reduction in greenhouse gas emissions per gasifier[8]**

[1]Reported system performance from domestic commercial gasifier vendor, January 2013
[2]Calculated based on emissions data from Airtech Environmental Services Inc., August 2012
[3]Reported by SCWA staff in biomass survey response, February 2012
[4]Harris and Phillips, Georgia Forestry Commission, February 1986
[5]Calculated in Table 4 based on 90% aerobic decomposition of bone dry woody biomass
[6]Calculated in Table 3 for a 1.0 MWe gasification system (10% of total)
[7]California Public Utilities Commission GHG Calculator, Version 3c, October 2010 (2014 estimate)
[8]Equivalent to a GHG emissions **reduction** of 1.35 kg CO2e/kWh, which falls within the range of -1.368 to +0.075 kg CO2e/kWh reported by the IPCC for lifecycle GHG emissions of biopower projects (2011)

Table 5B. Net reduction in GHG emissions from generating heat

Value	Units	Calculation
11,539	therms/yr	Avoided PG&E natural gas consumption per 100 kWe gasifier[1]
11.7	lb/therm	PG&E greenhouse gas emissions factor[2]
135,000	lb/yr	11,539 therms/yr * 11.7 lb/therm
0.454	kg/lb	Conversion factor for lb to kg
61,200	kg/yr	135,000 lb/yr * 0.454 kg/lb
1,000	kg/t	Conversion factor for kg to metric tons
61.2	t/yr	Avoided PG&E greenhouse gas emissions per gasifier
61.2	**t/yr**	**Net reduction in greenhouse gas emissions per gasifier**

[1]Calcuated in Table 8 based on 2011 PG&E natural gas consumption at 404 Aviation Boulevard
[2]California Public Utilities Commission GHG Calculator, Version 3c, October 2010 (all years)

Table 6. California ARB auction price per metric ton of GHG allowances

Auction Date	Reserve	Settlement	Change	Cumulative
Nov 2012	$10.00	$10.09	-	-
Feb 2013	$10.71	$13.62	35.0%	35.0%
May 2013	$10.71	$14.00	2.8%	38.8%
Aug 2013	$10.71	**$12.22**	-12.7%	21.1%

3. Economic Benefits

The economic benefits to the water agency of implementing a biomass gasification system are twofold: 1) avoided retail purchases of electricity and natural gas, and 2) income from the sale of excess electricity on the wholesale market. The monetary value of these benefits was calculated using actual SCWA energy consumption data from 2011 (the latest data set available at the time of the feasibility assessment) along with the projected energy delivery of a single BioMax 100 unit based on actual system performance data maintained by CPC.

SCWA energy consumption data were sorted into three categories—administration, water transmission, and wastewater treatment—to identify candidate sites for a bioenergy unit based on their annual PG&E electricity consumption. The tables in Appendix E summarize the results of this sort and identify three candidate sites, all of which consume a minimum of 230,000 kWh per year (roughly one-third of the annual output of the BioMax 100). The three sites selected were 404 Aviation Boulevard, the Airport Wastewater Treatment Plant (WWTP), and the R-4 Pump Station, with the first coming from the administration category

and the latter two from the wastewater treatment category.[8] Based on their relatively low PG&E energy use, no candidate sites were identified in the water transmission category.

For each of the candidate sites, the 2011 monthly load profile was examined to determine in which months its electricity demand exceeded the projected output of the BioMax 100 (~58,000 kWh) and in which months the gasifier could generate excess electricity for sale back into the grid via a power purchase agreement with Sonoma Clean Power (or through net energy metering credits from PG&E, an option that was not explicitly addressed in this BCA). A second set of tables in Appendix E shows the monthly load profile for each of the three candidate sites. One of the sites, 404 Aviation Boulevard, also uses PG&E natural gas for heating, and that consumption is included in Table E-2A as well.

To assess the economic value of avoided future energy purchases, current prices for PG&E electricity and natural gas established by the utility's most recent General Rate Case (GRC) for 2011-2013 were used as a baseline. Projected rate increases then were estimated using the GRC filed by the utility with the CPUC in November 2012 for the upcoming three-year revenue period (2014-2016). As noted in Table 7, some of the rate increases already have been approved by the CPUC, while others were awaiting approval at the time of this BCA. Based on these actual and projected rate data, annual increases of 4% in electricity rates and 10% in natural gas rates are expected from 2014 through 2016. To be precise, these represent compound annual (i.e., year-over-year) increases as opposed to average annual increases over the 2011-2013 baseline rates. These projected rate increases then were combined with actual SCWA energy consumption data from each candidate site in 2011 to determine expected cost savings for the water agency beginning in 2014. Table 7 provides further detail regarding how the rate projections were developed, while Table 8 shows the expected savings from avoided purchases of PG&E electricity and natural gas. Again, the only candidate site where natural gas is consumed is 404 Aviation Boulevard, thus there are no savings available from avoided purchases of PG&E natural gas at the other two sites.

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[8] Electricity consumption for 404 Aviation Boulevard includes the 204 Concourse at 1315 Airport Boulevard, as the two buildings are located on contiguous properties and consequently could potentially share bioenergy generation and distribution assets.

Table 7. Projected PG&E electricity and natural gas rate escalation (2014-2016)

Rate Increases	Total	2014		2015		2016		Cumulative	Average	Annual
General Rate Case[1, 2]	$2,282	$1,282	8.6%	$500	3.1%	$500	3.0%	14.7%	4.9%	**4.9%**
Renewable Electricity[3]	$540	$180	1.2%	$180	1.1%	$180	1.1%	3.4%	1.1%	**1.1%**
Pipeline Safety[4]	$1,200	$300	2.0%	$450	2.8%	$450	2.7%	7.5%	2.5%	**2.4%**
Total	**$4,022**	**$1,762**	**11.8%**	**$1,130**	**7.0%**	**$1,130**	**6.8%**	**25.6%**	**8.5%**	**7.9%**
GRC Impacts	**2011-2013**	**2014**		**2015**		**2016**		**Cumulative**	**Average**	**Annual**
Electricity[1]	$89.36	$93.97	5.2%	$95.77	1.9%	$97.57	1.9%	8.9%	3.0%	**3.0%**
Natural Gas[1]	$46.13	$53.18	15.3%	$55.93	5.2%	$58.68	4.9%	25.4%	8.5%	**8.4%**
Total	**$135.49**	**$147.15**	**8.6%**	**$151.70**	**3.1%**	**$156.25**	**3.0%**	**14.7%**	**4.9%**	**4.9%**

[1]Notice of public participation hearings regarding PG&E's 2014 General Rate Case (Phase 1), April 2013
[2]PG&E General Rate Case 2014-2016 website: http://www.grc2014facts.com/#thethe-tabs-1-1
[3]PG&E requested rate increase for new renewable generation, reported by the SF Chronicle on 7/26/12
[4]CPUC approved rate increase for pipeline safety improvements, reported by ABC News on 12/20/12

	Aggregate
Electricity	**4.0%**
Natural Gas	**10.0%**

Note 1: All rate increases in current year millions of dollars based on rate cases filed with the CPUC in 2012
Note 2: All GRC impacts in current year dollars based on 2010 national average residential energy costs
Note 3: Annual escalation indicates projected compound annual increase during 2014-2016 revenue period
Note 4: Aggregate annual rate increases for electricity and natural gas ***rounded down*** *to nearest integer*

Table 8. Annual gross economic benefit of a 100 kWe biomass gasifier (2014)

		Avoided Purchases of PG&E Electricity & Natural Gas						Excess Generation			Total
	Candidate Site	**kWh**	**$/kWh**	**Savings**	**Therms**	**$/Therm**	**Savings**	**kWh**	**$/kWh[1]**	**Sales**	**Gross Benefit**
1	404 Aviation Boulevard	284,154	0.178	$50,589	11,539	0.554	$6,387	411,846	0.116	$47,976	$104,952
2	Airport Wastewater Treatment Plant	688,400	0.153	$105,638	-	-	-	7,600	0.116	$885	$106,524
3	R-4 Pump Station	393,560	0.195	$76,601	-	-	-	302,440	0.116	$35,231	$111,832

[1]Assumes a fixed CCA purchase price of $116.49/MWh using the Marin Clean Energy baseload facility contract price (Condition 1) with a 20-year delivery term as a proxy

Note 1: Candidate site 1 would be a CHP application; candidate sites 2 and 3 would be electricity only
Note 2: 404 Aviation Boulevard and 1315 Airport Boulevard are located on contiguous properties
Note 3: Unit prices for avoided purchases of PG&E electricity escalated 4% annually from 2011 to 2014
Note 4: Unit price for avoided purchases of PG&E natural gas escalated 10% annually from 2011 to 2014

Table 8 also shows the gross economic benefits that are anticipated from the sale of excess electricity generation by the water agency to Sonoma Clean Power. As noted in the table, the unit price of 11.6 cents per kilowatt-hour is based on the rate set by the Marin Energy Authority ($116.49/MWh) for its baseload suppliers over a 20-year contract. Wholesale purchase prices expected to be offered by SCP were not available at the time the analysis was completed, so the MEA feed-in tariff was used as a proxy. Two of the candidate sites stand to generate significant revenues from the sale of excess generation, while the Airport WWTP, due to its high onsite consumption, does not. The fundamental trade-off between offsetting PG&E consumption and selling excess generation (and the economic benefits of each option) is addressed more fully in the net benefit discussion later in this report.

B. Estimated Costs

To maintain the framework of sustainability applied in the benefits portion of the BCA, the same three categories of social, environmental, and economic impacts were used to assess the anticipated costs to SCWA of acquiring a 100 kWe biomass gasification system. While most of the costs were directly quantifiable, some were evaluated only qualitatively given their minimal impact to the water agency and the residents of Sonoma and Marin counties.

1. Social Costs

There are no measurable social costs of implementing a biomass gasification system given the small footprint (30’ x 30’) of a pilot-scale unit, which easily could be installed on SCWA property and thus would not incur any opportunity cost associated with alternative public land uses. The system also conforms to both federal and state limits for occupational noise exposure. CPC reports that the engine-generators emit a maximum of 75 decibels (dB) at a distance of 10 feet under normal operating conditions. This is below the 80 dB threshold assigned by the U.S. Department of Labor’s Occupational Safety and Health Administration (OSHA) as the minimum level requiring measurement of worker exposure, and the 8-hour time-weighted average of 85 dB set as the federal action level requiring hearing protection for employees (Occupational Safety and Health Administration, 2008). Analogous limits on employee noise exposure are set forth in the California Code of Regulations (CCR) Title 8, Section 5096 - Exposure Limits for Noise.

2. *Environmental Costs*

The environmental impacts that would be incurred by Sonoma and Marin county residents from biomass gasification were found to be negligible. Although, as discussed previously, CO2 emissions from the gasifier would be higher than those from the existing PG&E power mix, they would not impose a cost since 1) the higher emissions would be *more than offset* by reductions in GHG emissions from avoided biomass decomposition (see Table 5A), and 2) the CO2 emissions from a biomass gasifier are carbon neutral and would displace fossil fuel emissions from conventional power plants used by PG&E to generate electricity. Also, because the system boundary defined for the benefit-cost analysis was limited to the local Sonoma County region, whereas the impacts of CO2 emissions in terms of climate change are felt on a global scale, those impacts were not directly applicable to this analysis. NOx emissions, the other environmental concern noted in Table 2, are also higher than those of the current PG&E power mix; however, they are well below both the California and federal emissions limits shown in Table 9, and consequently would not impose a cost to the water agency or to local residents in the form of smog or acid rain.

Table 9. Emissions limits for stationary sources using gaseous biogenic fuels

	Biomass Gasification		Federal Limit (U.S. EPA)		Below Limit	California Limit (BAAQMD)		Below Limit
	Value	*Units*	*Value*	*Units*	*Y/N*	*Value*	*Units*	*Y/N*
PM	0.716	mg/m3	0.150[1]	mg/m3	-	343[5]	mg/m3	**Y**
CO	17.9	ppmv	610[2]	ppmv	**Y**	2,000[6]	ppmv	**Y**
NOx	25.9	ppmv	150[2]	ppmv	**Y**	70[6]	ppmv	**Y**
SO2	0.049	lb/MMBtu	0.15[3,4]	lb/MMBtu	**Y**	-	-	-
	2.32	ppmv	-	-	-	300[7]	ppmv	**Y**
VOC[8,9]	0.717	ppmv	80[2]	ppmv	**Y**	-	-	-

[1]Limit is 24-hour National Ambient Air Quality Standard (NAAQS) for PM10 (included for reference only)
[2]40 CFR Part 60 Subpart JJJJ (Final Rule - August 29, 2011)
[3]40 CFR Part 60 Subpart KKKK (Final Rule - March 20, 2009)
[4]Limit is for stationary combustion turbines and does not apply to ICEs (included for reference only)
[5]BAAQMD Regulation 6, Rule 1, Section 310 (2007)
[6]BAAQMD Regulation 9, Rule 8, Section 302 (2007)
[7]BAAQMD Regulation 9, Rule 1, Section 302 (1995)
[8]THC emissions used as a proxy for VOC emissions, consistent with U.S. EPA guidelines (i.e., within +/- 7%)
[9]ICEs are exempt from California limits on VOC emissions per BAAQMD Regulation 8, Rule 1, Section 110.2 (1994)

Note 1: Biomass gasification emissions values from tests conducted by Airtech Environmental Services, Inc. on August 7, 2012
Note 2: Bay Area Air Quality Management District (BAAQMD) is the lead permitting agency for southern Sonoma County
Note 3: All values shown in parts per million volume (ppmv) are corrected to 15% oxygen, dry basis

3. Economic Costs

The expense of the biomass gasifier is by far the most significant cost driver in the BCA. In most cases, the water agency would be faced with the capital expense of purchasing its own gasifier; however, Community Power Corporation offers a leasing option as well, and that became the baseline for the cost estimates that follow.[9] Once again using a BioMax 100 for illustrative purposes, a detailed estimate of the costs of acquiring and operating a modular biomass gasification system were developed for lease periods of five and eleven years (the latter case being five years plus two three-year options). In addition to the monthly lease cost, expenses would be incurred by the water agency to operate and maintain the gasifier, including parts and labor costs for replacing filters, hoses, gaskets, and fluids, along with periodic (every 2-3 years) overhauls of the genset engines. Some site preparation costs also would be incurred (e.g., construction of a 30' x 30' concrete pad and feedstock cover) as well as the expense of any upgrades needed to the selected site's grid interconnection (e.g., buses, disconnects). Estimates of the annual outlays for all these cost elements are shown in the tables in Appendix F for the six cases included in this BCA (i.e., two different lease periods at each of the three candidate sites).

The monthly gasifier lease prices offered by CPC are based on a sort of profit sharing model in which the unit rates for delivered electricity (per kWh) and heat (per therm) are derived from the prices currently paid by potential customers. CPC strives to set its lease prices at a point that reduces energy costs for customers by 15-20%, while retaining the difference between the lease price and its total cost of delivery as profit. Consequently, gasifier leases are mutually beneficial for consumers and CPC in markets having relatively high unit prices for energy from utilities, but less so (particularly for CPC) in markets where existing energy prices are low. Scenarios that utilize both the electricity and heat generated by the gasifier (i.e., CHP) are generally more favorable than power-only applications, as they are able to take greater advantage of the energy content of the biomass feedstock. California has an average retail electricity price of $0.138/kWh, which is the ninth highest statewide average

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[9] Early discussions with SCWA staff indicated that any potential tax advantages from purchasing a gasifier would not be applicable given the agency's tax exempt status, so the leasing option (which would avoid any significant capital expense) was pursued as the primary acquisition strategy for this benefit-cost analysis.

and nearly 40% higher than the national average of $0.099/kWh (U.S. Energy Information Administration, 2013). Modular gasification systems can become difficult to "pencil out" in locations where the utility rates for electricity are below about $0.15/kWh, and the task is exacerbated in warmer climates with fewer thermal applications.[10] Sonoma County is thus a potentially challenging location in which to site a biomass gasifier, although as discussed later in this report, it can be done at a net financial gain under the right conditions.

The lease prices used for the five-year and eleven-year options examined in this BCA were based on the actual unit prices paid by SCWA for PG&E electricity and natural gas in 2011. Tables E-1A through E-2C in Appendix E show how those unit prices were determined for each of the three candidate sites. Because the gasifier would be used by the water agency for a combination of offsetting its PG&E purchases and generating excess electricity for sale to SCP, *blended unit rates* for electricity were used for the customer inputs to the CPC lease pricing model. A unique blended rate was developed for each site by prorating its current PG&E electricity purchases at the site-specific unit price (escalated 4% annually from 2011 to 2014) and the remainder of the 696,000 kWh generated annually by the BioMax 100 at the estimated SCP contract purchase price ($0.116/kWh). Table 8 above provides details regarding the assumed PG&E and SCP rates, while Table 10 below shows the blended rates used as inputs to the CPC lease pricing model. Outputs from that model are available with permission from Community Power Corporation.

Table 10. Blended unit rates used as inputs to the vendor lease pricing model

	Candidate Site	kWh	$/kWh	Therms	$/Therm
1	404 Aviation Boulevard	696,000	0.142	11,539	0.554
2	Airport Wastewater Treatment Plant	696,000	0.153	-	-
3	R-4 Pump Station	696,000	0.161	-	-

Note 1: 696,000 kWh is the approximate annual electricity output of a BioMax 100 (~80% CF)
Note 2: 11,539 therms is the usable thermal output of a BioMax 100 at 404 Aviation Boulevard
Note 3: No natural gas is consumed at the Airport WWTP or the R-4 Pump Station

[10] To mitigate this challenge, CPC has developed a thermal conversion process that uses the heat output from the gasifier to power a chiller for air conditioning during warmer months.

C. Net Benefit and Net Present Value

The tables in Appendix F show the itemized costs and benefits projected for each candidate site over both potential lease periods. The estimated outlays and receipts in each year are listed in current year dollars, with an annual *net benefit* (i.e., total benefit minus total cost) shown at the bottom of each column. The total column to the right of the annual estimates is the sum of costs or benefits accrued across multiple years in their current year dollars; therefore, to enable direct comparisons across the six cases, total values were converted to their net present values using 2014 as the base year. Details of the sources used and any assumptions made in developing the cost and benefit estimates are noted at the bottom of each table. As recommended by the White House Office of Management and Budget (OMB), nominal discount rates of 1.1% and 2.0% were used to calculate the NPVs for the five-year and eleven-year lease periods, respectively (Office of Management and Budget, 2012).

The net benefit for each of the six cases examined in this benefit-cost analysis (in terms of its net present value) is shown in Table 11. While all of the cases offer benefits to the water agency in terms of reducing carbon emissions, avoiding energy purchases from PG&E, and generating excess electricity for sale to Sonoma Clean Power or another wholesale power purchaser, only two of the cases yield a positive return when their monetized benefits are compared with the costs the agency would incur to install and operate a 100 kWe biomass gasification system. Therefore, only an 11-year lease at the Airport Wastewater Treatment Plant or the R-4 Pump Station can be considered viable investment options at this time. It should be noted that the same result would be produced if the agency were to purchase the biomass gasifier outright, as the $1.0-$1.2 million capital expense it would incur matches the total lease cost over an 11-year period (see Table F-2B and Table F-2C).[11] In addition, the NPV for both locations is only slightly positive—particularly in light of the large costs involved—and thus the water agency should predicate its final investment decision on the results of a sensitivity analysis, which are presented in the next section of this report.

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[11] An approximate purchase price for the BioMax 100 was provided by Community Power Corporation during a site visit in October 2012 (see Appendix D for more details).

Table 11. Summary of net benefits of leasing a 100 kWe biomass gasifier (NPV)

Candidate Site	Lease Period	Total Cost	Total Benefit	Net Benefit
404 Aviation Boulevard	5 Years	$699,246	$606,741	**($92,505)**
Airport WWTP	5 Years	$699,246	$632,149	**($67,097)**
R-4 Pump Station	5 Years	$699,246	$646,424	**($52,822)**
404 Aviation Boulevard	11 Years	$1,448,006	$1,343,787	**($104,219)**
Airport WWTP	11 Years	$1,448,006	$1,467,069	**$19,063**
R-4 Pump Station	11 Years	$1,448,006	$1,457,288	**$9,282**

Note 1: All dollar figures are a net present value (NPV) discounted to a base year of 2014
Note 2: Red indicates a leasing case having a negative net benefit (i.e., a negative NPV)

D. Sensitivity Analysis

The purpose of a sensitivity analysis is to test the robustness of the results produced by a BCA over a range of possible scenarios defined by the inherent uncertainty in one or more model inputs. This uncertainty is usually greater for projected benefits than for estimated costs, as expenditures generally can be quantified more easily based on vendor quotes or actual costs from similar projects. Benefits, on the other hand, are more forward-looking, requiring the analyst to make assumptions and predictions about the value that ultimately would be derived from pursuing a particular investment or course of action. For this BCA, substantial uncertainty exists in two key analysis parameters associated with the benefits of acquiring a modular biomass gasification system:

1. The annual escalation of retail electricity rates; and
2. The auction price per metric ton of GHG allowances.

To address these uncertainties explicitly in terms of their impact on the net present value of implementing a pilot-scale biomass gasification system in Sonoma County, two types of sensitivity analysis were performed. Both utilize a technique known as range estimating, with the first being a manual process and the second a more statistically rigorous method called Monte Carlo simulation. The same assumptions were used for both models, and are shown in Table 12. They consist of lower- and upper-bound estimates for each of the two model parameters of interest, which along with the base values from the BCA were used to assess worst- and best-case outcomes for the chosen investment option, respectively.

Table 12. Range estimating assumptions for sensitivity analysis models

Parameter	Low	Base	High
Annual escalation of retail electricity rates[1,2]	2.0%	4.0%	8.0%
Price per metric ton of GHG allowances[3,4]	$10.71	$12.22	$40.00

[1]Low value is the anticipated inflation rate for the next 10 years (Cleveland Fed, August 2013)
[2]High value is double the annual escalation rate projected for PG&E in Table 7
[3]Low value is the current ARB auction reserve price for 2013 vintage allowances
[4]High value is the established ARB reserve sale price under high demand scenarios

The investment option examined in the sensitivity analysis was an 11-year lease period at the Airport WWTP, which yielded the highest net benefit as indicated in Table 11. It stands to reason that if the water agency were to invest in biomass gasification at a single site, this location would be the most likely to produce a positive return on that investment given the costs and benefits included in the BCA. The results of the sensitivity analyses demonstrate that SCWA would in fact have a high likelihood of realizing a net financial gain from leasing a biomass gasifier over an 11-year period at that location.

Table 13A shows that, in a worst-case scenario in which retail electricity rates increase by only 2% annually (the anticipated rate of inflation over the next ten years) and the value of carbon offsets as measured by the ARB auction price for GHG allowances falls to a reserve price of $10.71 per metric ton, SCWA could lose more than $120,000 over an 11-year lease period. On the other hand, if retail electricity rates go up by 8% annually (double the rate projected for PG&E) and carbon offsets could be sold in California or a secondary market for $40.00 per metric ton, the water agency could realize a net financial gain of more than $700,000 over those same 11 years.

Table 13A. Manual sensitivity analysis results: Airport WWTP (11-year lease)

Benefit	Low	Base	High
Avoided purchases of PG&E electricity	$1,162,021	$1,282,916	$1,571,820
Monetized value of carbon offsets	$153,652	$175,315	$573,863
Net Benefit	**($123,495)**	**$19,063**	**$706,515**

Note: Net benefit values include all other costs and benefits listed in Table F-2B

What is not apparent from the results in Table 13A is the *probability* that the water agency would experience a net gain from its investment rather than a net loss. In order to assess this probability, a Monte Carlo simulation of 10,000 trails was run to estimate the full range of possible investment outcomes, as well as the shape of the distribution of those outcomes. Table 13B shows the minimum, median, and maximum values produced by the Monte Carlo simulation model, and Figures 5 and 6 depict the frequency and cumulative distributions of possible net present values of an 11-year gasifier lease at the Airport WWTP.

Table 13B. Monte Carlo simulation results: Airport WWTP (11-year lease)

Benefit	Minimum	Median	Maximum
Avoided purchases of PG&E electricity	$1,164,721	$1,317,800	$1,569,245
Monetized value of carbon offsets	$153,911	$284,473	$563,807
Net Benefit	**($114,678)**	**$170,492**	**$674,190**

Note 1: Net benefit values include all other costs and benefits listed in Table F-2B
Note 2: Monte Carlo simulation uses triangular distributions for the two model assumptions
Note 3: Monte Carlo simulation applies 0.5 correlation factor between the two model assumptions
Note 4: Monte Carlo simulation uses Latin Hypercube sampling method

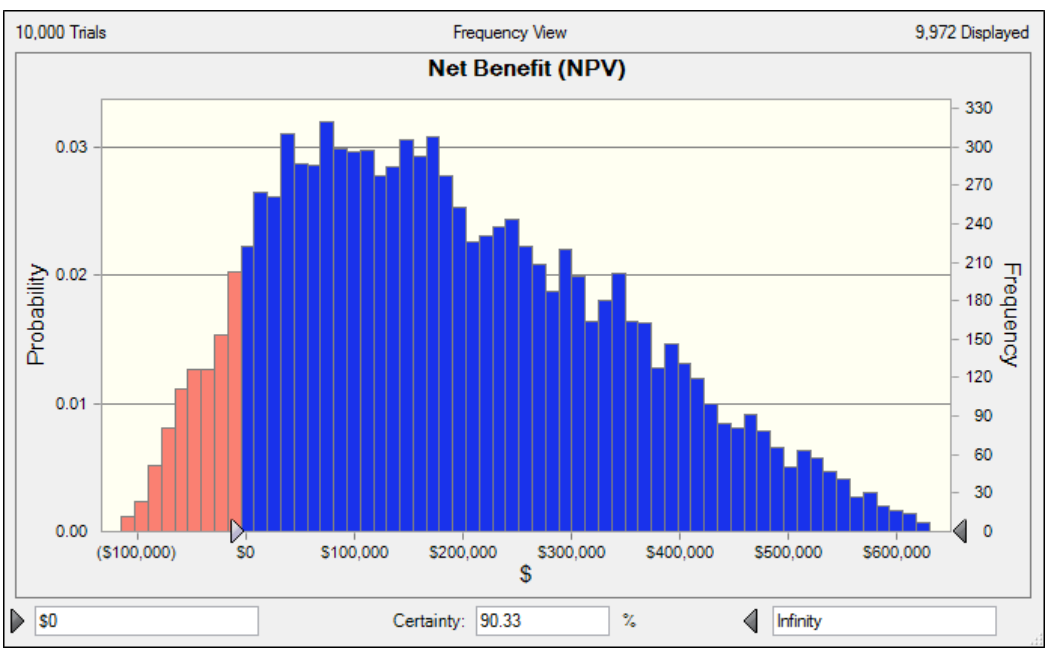

Figure 5. Frequency distribution of Monte Carlo simulation results

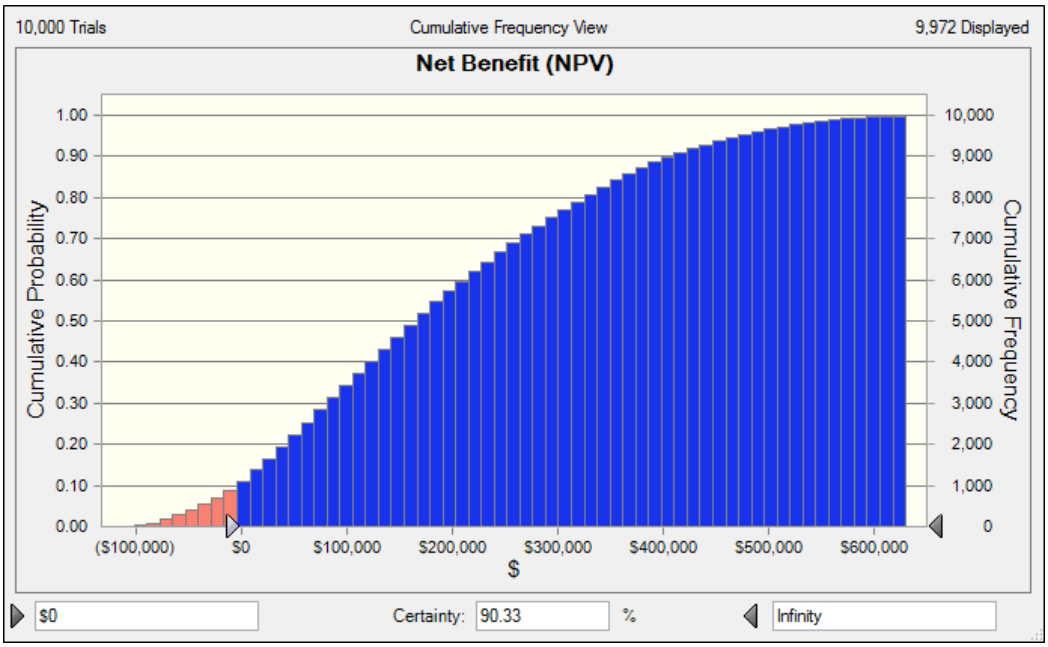

Figure 6. Cumulative distribution of Monte Carlo simulation results

As indicated by the certainty percentage at the bottom of each distribution, the water agency would have a greater than 90% probability of at least breaking even with this investment option. Stated another way, the agency would face a less than 10% chance of suffering a financial loss from securing an 11-year lease for a 100 kWe biomass gasifier at the Airport Wastewater Treatment Plant. This probability of experiencing a loss, shown in red in the two distributions, reflects the uncertainty associated with the assumptions used in the base case benefit-cost analysis. The most likely scenario, as indicated by the central tendency of the frequency distribution in Figure 5, would be for SCWA to realize a net gain of roughly $100,000 over 11 years. This estimate falls between the base case produced by the BCA (around $19,000) and the median value generated using Monte Carlo simulation (around $170,000). Note that the manual range estimating and Monte Carlo methods both produce similar best- and worst-case outcomes; however, the latter model provides much greater detail about the most likely range of outcomes falling between those two extremes. This should give the water agency greater confidence in the expected positive return from such an investment.

VI. RECOMMENDATIONS

In light of the water agency's goal of delivering carbon free water by 2015, the favorable energy policy climate that continues to evolve in California through mechanisms such as feed-in tariffs and net energy metering, and the emergence of distributed generation and community choice aggregators like Sonoma Clean Power as viable alternatives to existing electric utilities, this is a particularly opportune time for the agency to consider acquiring additional renewable energy generation assets. This feasibility assessment evaluated three bioenergy technologies in particular, examining the inherent strengths and disadvantages of biomass combustion, pyrolysis, and gasification. Based on the projected performance of each technology over a range of environmental, technical, logistical, and economic criteria, biomass gasification was found to be the best alternative for a pilot-scale system that could be operated using residual biomass that already is being produced by the agency's stream maintenance activities. The feasibility of this alternative was substantiated by a detailed benefit-cost analysis, which found that for two sites—the Airport Wastewater Treatment Plant and the R-4 Pump Station—a modular biomass gasification system could provide a *net financial benefit* to the water agency through a long-term leasing agreement that would obviate any significant capital investment. Accordingly, it is recommended that the water agency take the following two courses of action:

Recommendation 1. Sonoma County Water Agency should pursue the acquisition of a pilot-scale biomass gasification system at its Airport Wastewater Treatment Plant.

Recommendation 2. Sonoma County Water Agency should seek out municipal and/or commercial partnerships for procuring additional biomass feedstocks.

It must be noted again that these recommendations, discussed in greater detail below, rely upon key assumptions that should be validated by agency staff before any action is taken.

A. Pilot-Scale Biomass Gasification

Acquiring a pilot-scale biomass gasification system would offer several advantages over a "business as usual" scenario. These include a net reduction in the agency's GHG emissions,

lower PM emissions compared with the current PG&E power mix, and the opportunity to generate excess electricity that could be 1) sold to a wholesale power purchaser such as Sonoma Clean Power, or 2) returned to the grid for retail credits (in a NEM arrangement) or wholesale reimbursement from PG&E (through the Re-MAT feed-in tariff mechanism). As indicated by the high confidence level generated by the BCA sensitivity analysis, it is very likely that investing in a pilot-scale project of this type would result in a net financial gain for the water agency. The availability of modular biomass gasifiers from multiple domestic vendors provides SCWA with several choices for acquiring a pilot-scale system, with a long-term lease from Community Power Corporation being one potentially viable option. Lastly, another notable advantage of installing a pilot-scale system at the Airport Wastewater Treatment Plant is that it could be operated and maintained by the existing SCWA engineering and maintenance staff working at the site, and it could be fueled solely by available quantities of green waste being produced locally by the water agency.

B. Additional Feedstock Sources

Although up to two 100 kWe gasifiers could be fueled with the residual biomass produced by the agency's stream maintenance activities, scaling up generation beyond a pilot facility would require outside sources of biomass feedstocks. An initial objective of this feasibility assessment was to identify potential partners in Sonoma County that could supply SCWA with organic waste to fuel a bioenergy system; however, the large majority of the contacts provided by the agency did not respond to the survey developed at the outset of the study. Based on the positive results of this feasibility assessment, the water agency is encouraged to reconnect with those contacts in the local agricultural and winemaking industries, and to identify new municipal and/or commercial partners as potential sources for the additional biomass feedstocks that would be needed to support utility-scale gasification operations if the agency were to decide to expand beyond a pilot system.

C. Further Analysis

There are several other essential considerations in deciding if it would be feasible to scale up the generating capacity of a pilot system, or to create a network of modular systems. Thus, it also is recommended that the agency conduct further analyses before making that

decision in the future. For example, most of the potential outside feedstock sources that the agency has identified to date are agricultural producers (specifically vineyards and wineries) that are likely to have high seasonal variation in their waste streams as well as feedstocks with higher moisture contents that usually can be handled in bulk. Conversely, municipal and commercial wastes are often less seasonal, have lower moisture contents, and have larger form factors (i.e., are bulkier), and as a result require different handling, transportation, and storage processes. The amount of cutting, drying, and densification needed for biomass feedstocks is determined by both the specific gasification technology employed and the power generation efficiency required. Densification also can be used to minimize the amount of onsite storage needed, as well as to facilitate feedstock transport and delivery. To supply the larger feedstock volumes that would be needed for a utility-scale system, the agency likely would have to construct and operate a densification unit itself or outsource that service to another entity, a decision that would drive some of the costs (and risks) of implementing a larger bioenergy facility.

In addition, there are multiple contracting strategies that could be adopted by SCWA in its procurement of outside feedstocks. The first is that it could perform this function itself by establishing independent purchasing agreements with various green waste producers such as local municipalities, commercial tree trimming and landscaping services, and vineyards and orchards. The second is that it could outsource this process by engaging in a long-term purchasing agreement with an existing third party that is able to perform or coordinate the handling, transportation, and densification processes for a fee (e.g., an existing composting facility or processed wood manufacturer). A third option would be to form a cooperative among various producers that could supply the agency and other potential consumers with a reliable source of biomass feedstocks. This approach may have the advantage of allowing the agency to establish a single, long-term supply contract as opposed to multiple smaller contracts with various producers, thereby reducing administrative costs. Feedback offered by agency staff during the course of this feasibility assessment indicated that SCWA would prefer to minimize the administrative and logistical requirements related to procuring and managing additional biomass feedstocks, therefore this issue would merit further analysis before moving beyond pilot-scale operations.

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APPENDIX A – BIOMASS SURVEY & SONOMA COUNTY WATER AGENCY RESPONSE

Sonoma County Water Agency
404 Aviation Boulevard
Santa Rosa, CA 95403

January 12, 2012

Dear Prospective Participant:

I am writing to kindly request your participation in a research effort I am currently leading on behalf of the Sonoma County Water Agency to identify local sources of biomass that could be used as fuel for a renewable energy facility. As a public organization committed to promoting environmental stewardship and reducing its carbon footprint, the agency is investigating the feasibility of generating a portion of its own electricity from local, renewable sources. Sonoma County, with its extensive agricultural and winemaking industries, offers a range of potential sources of biomass feedstock. Our research is specifically focused on vineyards, wineries, and tree trimming/landscaping services, with the primary objectives being 1) to identify locally available sources of agricultural waste and woody refuse that could be suitable for producing electricity through combustion or other related technologies; 2) to determine the types and quantities of biomass available from those local sources; 3) to assess the logistics associated with collecting, transporting, processing, and storing the biomass materials; and 4) to estimate the cost of procuring biomass feedstocks in sufficient quantities to support regular operation of an energy generating facility to serve the Sonoma County Water Agency and its customers.

Your involvement in this research effort, which is being conducted to fulfill the requirements of the Master of Public Policy (MPP) degree at the Richard and Rhoda Goldman School of Public Policy at the University of California, Berkeley, would entail completing a brief survey either by phone or email. Should your organization become interested in collaborating further on this effort, I would connect you with the agency's Public Information Officer, Amy Bolten.

I will be contacting you shortly regarding the specifics of the survey. In the meantime, I would be happy to discuss any questions you may have about this study. I can be reached via email at wdfeatherman@berkeley.edu or by phone at 510-000-0000 (office) or 619-000-0000 (mobile). Thank you in advance for your time, and I look forward to hopefully working with you on this project in the coming weeks.

Sincerely,

W. David Featherman, P.E.
Goldman School of Public Policy
University of California, Berkeley

SURVEY OF BIOMASS SOURCES IN SONOMA COUNTY

RESPONSE RECEIVED FROM SONOMA COUNTY WATER AGENCY
6 FEBRUARY 2012

This survey is being conducted as part of a research effort by the Sonoma County Water Agency (SCWA) to identify local sources of biomass that could be used as fuel for a renewable energy generating facility. The objectives of the survey are 1) to identify locally available sources of agricultural waste and woody refuse that could be suitable for producing electricity through combustion or other related technologies; 2) to determine the types and quantities of biomass available from those local sources; 3) to assess the logistics associated with collecting, transporting, processing, and storing the available biomass materials; and 4) to estimate the cost of procuring biomass feedstocks in sufficient quantities to support regular operation of an energy generating facility to serve SCWA and its customers.

The survey below can be completed in approximately **20-30 minutes**, depending upon the availability of specific information. Responses can be submitted by email, telephone, or fax. To schedule a telephone interview or to respond electronically, please email me at wdfeatherman@berkeley.edu. I also can be reached by phone at 510-000-0000 (office/fax) or 619-000-0000 (mobile). If your organization would like to collaborate further with SCWA on this effort, you are encouraged to contact their Public Information Officer, Amy Bolten, at 707-000-0000.

Please submit your responses as soon as possible, but no later than **Wednesday, February 1st** so we are able to include them as part of our assessment. Thank you for your participation, and we look forward to hearing from you.

1. Does your organization produce agricultural waste or woody refuse as part of its normal operations, and if so, what types of biomass materials are produced (e.g., vines, tree branches, crop residues)?

Yes, we generate agricultural waste from trees, shrubs, and blackberries.

2. Please specify the quantity produced annually for ***each type*** of biomass listed in Question 1. Estimates should be in cubic yards or pounds if possible.

We produce approximately 10,500 cubic yards of wood chips and some blackberries per year.

3. Are these quantities produced evenly throughout the year, or are there significant seasonal variations? If so, please specify.

No, the majority is produced from June through October (9,000 cubic yards); the remainder is produced from November through May (1,500 cubic yards).

4. Where are the biomass materials produced? Please provide an address if possible so we can locate it on a map. If materials are produced in multiple locations, please list them separately or specify if the materials are aggregated at a central location prior to disposal.

The majority of the material is produced from flood control channels located throughout central and southern Sonoma County. The remainder is generated at other SCWA facilities.

5. How are the biomass materials collected and aggregated for disposal (e.g., loose, in bulk, in bales)? Please specify whether this is done by hand or machine, using trucks/ forklifts, or by other means.

The majority of biomass material is chipped and hauled in our chipper trucks. If wood rounds are too large to chip they are hauled separately on top of the chipped material.

6. Are biomass materials reduced in size to facilitate handling prior to disposal (e.g., using a chipper, shredder, or grinder)?

Yes, the majority is run through a chipper.

7. Are biomass materials dried to reduce their moisture content prior to disposal? If possible, please estimate the moisture content (%) of the biomass materials at the time they are collected and, if applicable, after they have been dried.

No.

8. How do you currently dispose of these biomass materials? If you use different means to dispose of different materials, please specify each along with its relevant proportion (e.g., 50% of vines burned onsite and 50% of vines landfilled, 100% of branches recycled, 100% of crop residues composted).

We utilize a variety of disposal sites. The majority of the material is used as mulch or composted. Usually it is best to have a dump site near the area where work is being done.

9. Do you pay a fee to dispose of your biomass materials, and if so how much? Please specify the unit cost for each type of disposal (e.g., tipping fee [per vehicle load or per ton] at a municipal or private landfill, composting facility, or recycling center; hauling fee for disposal by a third party).

The only time a disposal fee is paid is for a mix of soil and organic material. The cost associated with this material is $4.00 per cubic yard.

10. Do you receive payment for recycling any of your biomass materials, and if so how much? Please specify the payment received per unit of material (e.g., $/ton of recycled wood, $/vehicle load of compostable material).

No.

11. Would your organization be interested in supplying SCWA with biomass materials as feedstock for a renewable energy facility, and if so, under what conditions/limitations?

Yes, provided that our normal operations are not delayed due to delivering or loading material to/for the energy facility.

12. Would SCWA incur any costs in accepting biomass waste from your organization (e.g., unit cost of materials, transportation costs)?

Indirectly, if the Stream Maintenance Program has to incur the costs and time to deliver the biomass material, then the efficiency of our program would be impacted.

13. Do you know of—or can you foresee—any potential barriers to your organization supplying SCWA with biomass materials as feedstock for a renewable energy facility?

Only delivery or loading of the biomass fuel.

14. Is there any additional information you would like to share that might be pertinent to this study? Feel free to elaborate on any of the answers you provided above, or to raise any issues or concerns you may have regarding this research specifically or the potential for a renewable energy facility in Sonoma County in general.

One way to mitigate the delivery problem of the biomass could be to have centralized stockpiles located in a few areas in central and southern Sonoma County. Locations should include Petaluma, Rohnert Park, and central or northern Santa Rosa. This would make the return trips of the chipper trucks shorter and more efficient; however, there would have to be personnel available to load the trucks from these centralized sites, including the equipment to do so.

APPENDIX B – PYROLYSIS SYSTEM UNIT CAPITAL COST ESTIMATE

Table B-1. Unit capital cost estimate for a biomass pyrolysis system

Value	Units	Calculation
60.9	$MM	Partial capital cost estimate for biomass pyrolysis system[1]
7.43	$MM	Heat recovery, power production, and utilities (base, 2003)[1]
3.45	-	Scaling, installation, and cost escalation factor[1]
25.6	$MM	$7.43 MM * 3.45
35.0	%	Equipment contingency factor[1]
34.6	$MM	$25.6 MM * 1.35
95.5	$MM	$60.9 MM + $34.6 MM
2,000	t/day	Assumed pyrolysis system feedstock throughput (daily)[1]
83.3	t/hr	2,000 t/day / 24 hr/day
142	kWh/t	Average efficiency of pyrolysis systems in literature review[1]
11,900	kW	83.3 t/hr * 142 kWh/t
1,000	W/kW	Conversion factor for kW to W
11,900,000	W	Average power of pyrolysis systems in literature review
8.03	**$/W**	**$95.5 MM / 11,900,000 W**

[1]Pacific Northwest National Laboratory, February 2009

Note 1: Original detailed capital cost estimate excluded heat recovery, power production, and utilities
Note 2: Unit cost for a modular pyrolysis system likely would be higher than for a utility-scale system

APPENDIX C – GASIFICATION SYSTEM CONVERSION EFFICIENCY AND COST DATA

Table C-1. Efficiencies and costs of existing biomass gasification systems

Project	Location	Year	Thermal Input		Power Output[1]		Thermal Output		Heat Losses		Cost ($MM)	
			MW	*%*	*MWe*	*%*	*MW*	*%*	*MW*	*%*	*Total*	*per MWe*
1 TUV-FICFB CHP	Gussing, Austria	2001	8.00	100%	2.00	25%	4.50	56%	1.50	19%		
2 Downdraft CHP	Wiener Neustadt, Austria	2003	2.00	100%	0.50	25%	0.70	35%	0.80	40%		
3 Varmevaerk Updraft CHP	Harboore, Denmark	1993	5.00	100%	1.50	30%	2.00	40%	1.50	30%		
4 Castor Gasification CHP	Graested, Denmark	2003	3.91	100%	0.90	23%	2.07	53%	0.94	24%		
5 TK Energi Downdraft Gasifier 1	Denmark	2006	3.13	100%	1.00	32%	1.75	56%	0.38	12%	4.12	4.12
6 TK Energi Downdraft Gasifier 2	Gjol, Denmark	2006	2.30	100%	0.69	30%	1.15	50%	0.46	20%		
7 TK Energi Downdraft Gasifier 3	Japan	2006	0.83	100%	0.20	24%	0.50	60%	0.13	16%	1.33	6.64
8 NOVEL Updraft Gasifier	Kokemaki, Finland	2006	7.00	100%	1.80	26%	4.30	61%	0.90	13%	6.64	3.69
9 CFB Bioflow Pressurized CHP	Varnamo, Sweden	2000	18.0	100%	6.00	33%	9.00	50%	3.00	17%	23.9	3.98
		Average	**5.6**	**100%**	**1.6**	**27.6%**	**2.9**	**51%**	**1.1**	**21%**	**9.0**	**4.61**

[1]Maximum power generation efficiency of biomass gasification is 40-45% (EURELECTRIC, Efficiency in Electricity Generation, July 2003; MWM gas engine-generator specifications)

Note 1: Data summarized from IEA Bioenergy Agreement, Task 33: Thermal Gasification of Biomass, Workshop No. 1: Perspectives on Biomass Gasification, May 2006
Note 2: Applies a Euro to dollar conversion rate of 1 EUR per 1.32815 USD (as of 8/2/13)

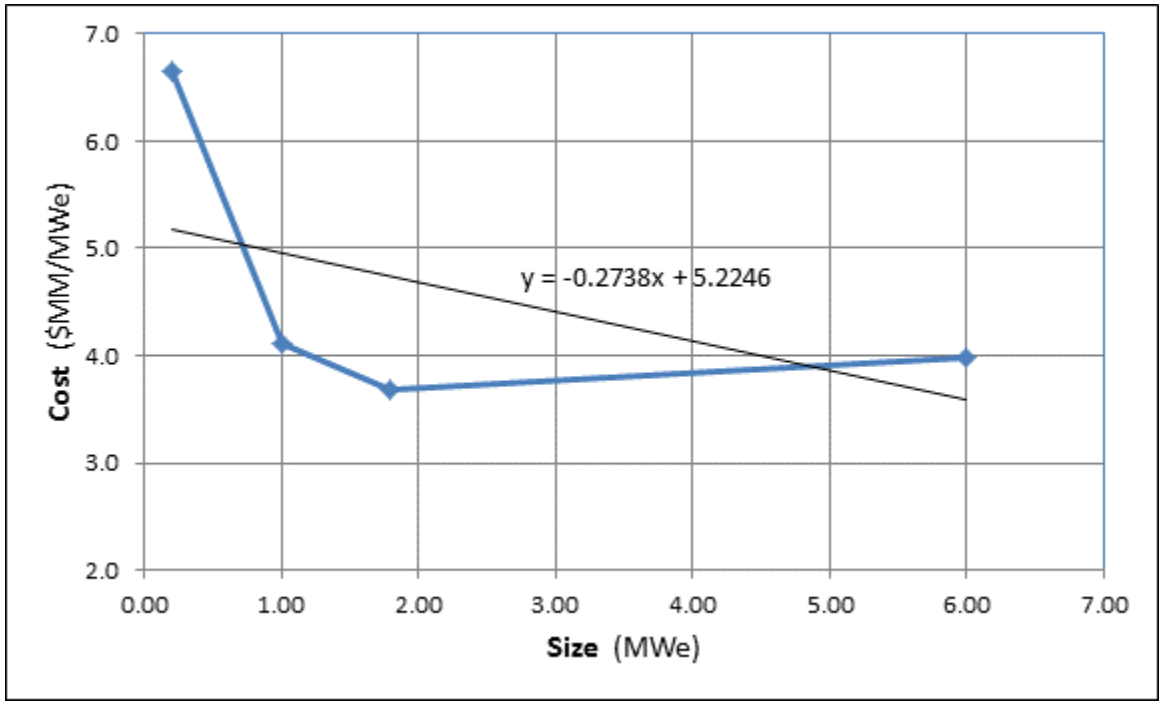

Figure C-1. Biomass gasification system cost versus system size

APPENDIX D – NOTES FROM COMMUNITY POWER CORPORATION SITE VISIT

LITTLETON, COLORADO
19 OCTOBER 2012

Costs

1. What is the maximum nameplate capacity of a BioMax system (kW)?

   100 kWe per unit (30' x 30' footprint); up to 500 kWe banked (76' x 84' footprint)

2. How much electricity can actually be generated (kWh/month)?

   Assume a capacity factor of ~80% = 58,000 kWh/month (approx.)
   Syngas energy content = 130 Btu/cubic foot (approx.)

3. What is the full capital cost of a BioMax system, including transport ($/kW)?

   $1.0-1.2 million per 100 kWe

4. What portion of the capital costs is paid by the system end user (% or $)?

   Customer generally provides concrete pad, feedstock storage/cover, heating
   CPC generally provides shipping, electrical connections, testing/commissioning

5. How much does CPC charge for the electricity it generates ($/kWh)?

   15-20% less than current utility price per kWh (profit sharing model)

6. What planned O&M costs are incurred for the system ($/year)?

   ~$30k/year

7. How much downtime does the system typically require (hr/month)?

   27.1 hours/month average O&M time for manual labor
   30-45 minutes per day for routine maintenance/cleaning
   75-80% system uptime overall

8. How much feedstock is needed to operate a BioMax system (cy/day)?

   2.0-2.4 dry short tons/day (3.0-3.5 wet short tons/day) = 200 dry pounds/hr
   ~11 cy/day (my estimate based on 337 dry lb/yd^3 and 80% CF)

9. What are the feedstock size and moisture content tolerances (cm; %)?

   <2" woodchips (no dust or strings); 12-15% moisture content

10. What is the full emissions profile of the BioMax system (tons; PPM)?

    a. **CO2** - *462x2 metric tons/yr = 1,328 kg/MWh = 2,927 lb/MWh (my calculation; gross)*
       CO2 - *3,077 lb/MWh (calculation by Jim Diebold, CPC principal scientist; net @ 96%)*

    b. **PM** - *1.73E-03 metric tons/yr*

    c. **CO** - *1.73E-01 metric tons/yr*

    d. **NOx** - *4.19E-01 metric tons/yr*

    e. **SO2** - *5.28E-02 metric tons/yr*

    f. **THC** - *1.09E-02 metric tons/yr*

Benefits

11. For how long is a BioMax system designed to operate continuously (years)?

    5 years under the standard lease contract; designed to last up to 15 years if purchased

12. How many BioMax systems are currently in operation (number; total kW)?

    35-40 systems deployed worldwide; sizes include 15 kWe, 25 kWe, 50 kWe, 75 kWe, 100 kWe
    Three 100 kWe units currently deployed (Dixon Ridge, Ft. Carson, Manitoba)
    Shipping two additional 100 kWe units in 2012 (Kauai, New York)
    One running at CPC now, also slated for delivery to Hawaii in 2013

13. What modifications are necessary for the system to be grid connected (number; $)?

    BioMax 100 is designed to be grid connected; may have to install additional disconnects or upgrade buses on the customer side

14. What is the typical payback period for CPC or the system end user (years)?

    Varies based on existing cost of electricity and heating/cooling

15. By how much can a system end user reduce their carbon footprint (tons CO_2e/yr)?

    Systems are carbon neutral (or carbon negative given the 2% of carbon sequestered in char ash); refer to UC Davis research paper for more information

16. How much heating/cooling is available from system byproducts (Btu/month)?

    350,000-400,000 Btu/hr from the genset; sufficient to run a 15-20 ton chiller through thermal conversion (waste heat from heat exchanger also can be used to dry feedstock)

General

17. What is the design/construction/delivery lead time for a BioMax system?

    Approximately 6-9 months from time of order to delivery of BioMax 100

18. What types of contractual relationships does CPC offer to system end users?

    Sale, lease, or energy services agreement (typically five years at a fixed price per kWh)

    4 pricing models for leasing/energy services agreement:

    1. ***Full Service & Maintenance*** *– CPC provides full-time onsite operator and maintenance*
    2. ***Minimal Self-Maintenance*** *– customer operates and performs daily maintenance; CPC provides weekly/monthly maintenance and "high end" service biennially*
    3. ***Standard Self-Maintenance*** *– customer operates and performs daily/weekly/monthly maintenance (0.15 FTE); CPC provides "high end" service biennially* ***(most common)***
    4. ***Full Self-Maintenance*** *– customer operates and performs all maintenance/service*

19. Why is the BioMax design superior to other modular gasification units?

    - Systems are relatively small; can be shipped in 20' containers via truck or boat and banked into groups of five onsite
    - Cleaner operation due to downdraft design; <5 ppm char ash in syngas
    - No water required for operation

20. What problems have arisen during delivery/operation of the BioMax system?

    ***Permitting** – requires 2-6 months for electrical interconnection (usually the longest) and air quality; cost of permitting included in purchase price or lease*

21. What other costs/benefits have you experienced with the BioMax system?

    - Syngas also can be converted into liquid fuels to offset diesel/gasoline consumption;
    - Customer recognition and awards (e.g., Dixon Ridge Farms);
    - General social benefits due to carbon neutrality

22. Is there any other information you would like to share about the BioMax or CPC?

    Difficult to make system cost effective without CHP when retail electricity price is <$0.15/kWh; "Virtual net metering" necessary to capture the difference between retail credit (greater) and wholesale sell back price (less)

APPENDIX E – SCWA ENERGY CONSUMPTION MODELS (2011)

Table E-1A. Annual PG&E electricity consumption: Administration

Asset		kWh	PG&E Billed	Unit Price
T03	404 Aviation Boulevard (New Administration)	15,271	$2,923.56	$0.184
T04	404 Aviation Boulevard (Solar Account)	112,433	$14,884.68	$0.131
T05	2150 W. College Avenue (O&M Trailer)	5,037	$948.59	$0.167
T06	2150 W. College Avenue (Old Administration)	258,671	$39,187.74	$0.151
T07	1315 Airport Boulevard (204 Concourse)	127,530	$22,587.70	$0.176
T08	2150 W. College Avenue (Lighting)	1,206	$342.76	$0.195
Total		**520,148**	**$80,875.03**	**$0.155**

Note 1: Red indicates potential site for 100 kWe gasifier based on annual consumption and unit price
Note 2: 404 Aviation Boulevard and 1315 Airport Boulevard are located on contiguous properties

Table E-1B. Annual PG&E electricity consumption: Water Transmission

Asset		kWh	PG&E Billed	Unit Price
T01	Mirabel Storage Facility	27,390	$4,888.29	$0.175
T02	Wohler Gate	160	$135.68	$0.173
T09	Cotati Water Tanks	5,109	$991.19	$0.173
T10	Cotati Sump Pumps	460	$180.93	$0.159
T11	Ely Road Sump Pumps	2,506	$553.36	$0.178
T12	McNear Avenue Sump Pumps	717	$231.62	$0.172
T13	Cinnabar Avenue Rectifier	0	$108.16	-
T14	Apple Valley Lane Sump Pumps	13	$109.91	$0.151
T15	Bellevue Sump Pumps	3	$108.58	$0.228
T16	Brookwood Street Sump Pumps	10	$109.61	$0.161
T17	Corrillo Sump Pumps	0	$108.05	-
T18	Hearn Avenue Valve Station	1,235	$320.74	$0.172
T19	Jennings Avenue Sump Pumps	6	$114.62	$1.067
T20	Kawana Springs Water Tank	3,690	$732.70	$0.169
T21	Lake Ralphine Water Tanks	1,780	$413.84	$0.172
T22	San Miguel Road Sump Pumps	6	$109.11	$0.174
T23	Summerfield Drive Sump Pumps	12	$109.79	$0.152
T24	Talbot Avenue Sump Pumps	11	$109.82	$0.159
T25	Yulupa Avenue Sump Pumps	0	$108.06	-
T26	Hart Lane Valve Station	2,183	$514.87	$0.186
T27	Wine Country Polo Field Sump Pumps	0	$109.02	-
T28	3rd Street Sump Pumps	249	$159.15	$0.206
T29	9th Street Sump Pumps	0	$113.61	-
T30	Warm Springs Dam	6,845	$1,887.24	$0.260
T31	Early Warning Station	117	$128.29	$0.173
T32	Foreman Lane Stream Gauge	0	$108.12	-
T33	Forestville Water Tanks	853	$253.72	$0.171
T34	Kastania Road Sump Pumps	1,328	$324.80	$0.163
T35	Kastania Water Tank	1,409	$350.42	$0.172
T36	Sonoma Water Tanks	1,897	$434.14	$0.172
T37	Hillside Water Tank	684	$227.04	$0.174
T38	Dunbar Road Valve Station	1,209	$316.17	$0.172
T39	Dunbar Road Sump Pumps	81	$121.19	$0.163
T40	Riverside Drive Sump Pumps	294	$158.72	$0.173
T41	Los Guilicos Water Tank	1,279	$328.27	$0.172
T42	5th Street Sump Pumps	760	$230.15	$0.161
T43	Agua Caliente Sump Pumps	487	$202.83	$0.195
T44	Boyes Boulevard Sump Pumps	2	$108.29	$0.144
T45	Madrone Road Sump Pumps	164	$132.19	$0.147
T46	Verano Avenue Sump Pumps	0	$108.00	-
Total		**62,951**	**$15,860.29**	**$0.183**

Note 1: Consumption for assets T03 through T08 included in Administration (Table E-1A)
Note 2: No assets consume sufficient electricity to support acquisition of a 100 kWe gasifier

Table E-1C. Annual PG&E electricity consumption: Wastewater Treatment

Asset		kWh	PG&E Billed	Unit Price
W01	Airport Treatment Plant	995,808	$135,848.87	$0.136
W02	Wikiup Lift Station	990	$331.08	$0.225
W03	Geyserville Treatment Plant	123,533	$18,854.80	$0.152
W04	Hamilton Lift Station	14,427	$2,614.79	$0.174
W05	Occidental Lift	21,376	$3,771.82	$0.171
W06	Occidental Treatment Plant	112,441	$17,001.85	$0.150
W07	Occidental Sewage Well	0	$108.16	-
W08	Graton Road Irrigation Pump	3,364	$1,461.35	$0.402
W09	Penngrove Pump Station	47,323	$8,000.09	$0.167
W10	Center Way Lift	12,648	$2,254.05	$0.170
W11	Drake and Western Lift	5,701	$1,026.00	$0.161
W12	Drake Road Lift	13,876	$2,418.31	$0.167
W13	Laughlin Road Lift	4,737	$893.62	$0.166
W14	Rio Nido Road Lift	13,050	$2,322.33	$0.170
W15	Russian River Main Lift	182,035	$28,024.20	$0.153
W16	Watson Road Lift	5,624	$1,041.35	$0.166
W17	BPJ1 Pump Station	0	$163.34	-
W18	Hill Road Lift Station	519	$197.31	$0.172
W19	R-4 Pump Station	511,683	$88,536.83	$0.173
W20	Warm Springs Lift	1,126	$347.28	$0.213
W21	Central Lift Station	545	$252.89	$0.266
W22	Sea Ranch Central Treatment Plant	30,855	$5,446.12	$0.173
W23	Sea Ranch North Treatment Plant	120,053	$18,323.61	$0.152
W24	North Lift Station	1,741	$462.64	$0.204
W25	Sea Ranch Main Lift Station	4,949	$1,005.55	$0.181
W26	Helm Lift Station	2,877	$650.01	$0.188
W27	South Lift Station	514	$251.23	$0.279
Total		**2,231,795**	**$341,609.49**	**$0.152**

Note 1: Red indicates potential site for 100 kWe gasifier based on annual consumption and unit price
Note 2: Airport Treatment Plant (W01) located approximately 0.5 miles from 404 Aviation Boulevard
Note 3: R-4 Pump Station (W19) located near Sonoma, CA, approximately 40 miles from Santa Rosa

Table E-2A. Monthly PG&E energy consumption: 404 Aviation Boulevard

	kWh	Therms	PG&E Billed	Unit Price
Annual Electricity Consumption (includes AC)	255,234	-	$40,395.94	$0.158
Annual Natural Gas Consumption (mainly heating)	-	23,476	$9,762.79	$0.416
Total	**255,234**	**23,476**	**$50,158.73**	-
Monthly Electricity Consumption	**2011**	**kWh**	**Excess Generation**	
	Jan	46,794	11,206	19%
	Feb	21,960	36,040	62%
	Mar	12,520	45,480	78%
	Apr	-640	58,000	100%
	May	-17,800	58,000	100%
	Jun	-10,480	58,000	100%
	Jul	29,360	28,640	49%
	Aug	28,960	29,040	50%
	Sep	36,840	21,160	36%
	Oct	35,040	22,960	40%
	Nov	29,160	28,840	50%
	Dec	43,520	14,480	25%
	Total	**255,234**	**411,846**	**59.2%**
100 kWe gasifier generates ~100 kWe * 24 hrs/day * 30 days/mo * 0.80 capacity factor =			57,600	
Monthly Natural Gas Consumption	**2011**	**Therms**	**Unmet Demand**	
	Jan	3,857	2,857	74%
	Feb	2,840	1,840	65%
	Mar	3,262	2,262	69%
	Apr	2,548	1,548	61%
	May	1,560	560	36%
	Jun	1,593	593	37%
	Jul	760	0	0%
	Aug	807	0	0%
	Sep	972	0	0%
	Oct	1,016	16	2%
	Nov	1,624	624	38%
	Dec	2,637	1,637	62%
	Total	**23,476**	**11,937**	**50.8%**
100 kWe gasifier generates ~350,000 Btu/hr * 1.00E-05 therms/Btu * 24 hrs/day * 30 days/mo * 0.80 CF =				2,016

Note 1: Electricity consumption in all months is less than electrical output of 100 kWe gasifier (~58,000 kWh/month)
Note 2: Negative electricity consumption indicates excess generation from existing rooftop solar PV
Note 3: Conservatively assumes only 50% usage of total available thermal energy (~1,000 therms/month)
Note 4: Red indicates monthly heating load exceeds usable thermal output of 100 kWe gasifier

Table E-2B. Monthly PG&E energy consumption: Airport WWTP

	kWh	Therms	PG&E Billed	Unit Price
Annual Electricity Consumption	995,808	-	$135,848.87	$0.136
Annual Natural Gas Consumption	-	0	$0.00	-
Total	**995,808**	**0**	**$135,848.87**	-
Monthly Electricity Consumption	**2011**	**kWh**	**Excess Generation**	
	Jan	117,408	0	0%
	Feb	82,800	0	0%
	Mar	145,200	0	0%
	Apr	68,400	0	0%
	May	90,000	0	0%
	Jun	50,400	7,600	13%
	Jul	82,800	0	0%
	Aug	67,200	0	0%
	Sep	66,000	0	0%
	Oct	67,200	0	0%
	Nov	70,800	0	0%
	Dec	87,600	0	0%
	Total	**995,808**	**7,600**	**1.1%**
100 kWe gasifier generates ~100 kWe * 24 hrs/day * 30 days/mo * 0.80 capacity factor =			57,600	

Note 1: Red indicates monthly electricity consumption exceeds electrical output of 100 kWe gasifier (~58,000 kWh/month)
Note 2: No natural gas consumed at this location

Table E-2C. Monthly PG&E energy consumption: R-4 Pump Station

	kWh	Therms	PG&E Billed	Unit Price
Annual Electricity Consumption	511,683	-	$88,536.83	$0.173
Annual Natural Gas Consumption	-	0	$0.00	-
Total	**511,683**	**0**	**$88,536.83**	**-**
Monthly Electricity Consumption	**2011**	**kWh**	**Excess Generation**	
	Jan	15,706	42,294	73%
	Feb	3,523	54,477	94%
	Mar	3,925	54,075	93%
	Apr	3,251	54,749	94%
	May	17,342	40,658	70%
	Jun	94,479	0	0%
	Jul	73,707	0	0%
	Aug	77,727	0	0%
	Sep	59,049	0	0%
	Oct	94,655	0	0%
	Nov	66,506	0	0%
	Dec	1,813	56,187	97%
	Total	**511,683**	**302,440**	**43.5%**
100 kWe gasifier generates ~100 kWe * 24 hrs/day * 30 days/mo * 0.80 capacity factor =			57,600	

Note 1: Red indicates monthly electricity consumption exceeds electrical output of 100 kWe gasifier (~58,000 kWh/month)
Note 2: No natural gas consumed at this location

APPENDIX F – NET BENEFIT AND NET PRESENT VALUE MODELS (2014)

Table F-1A. 5-year gasifier lease model: 404 Aviation Boulevard

	2014	2015	2016	2017	2018	Total	NPV
Costs							
Site preparation (concrete pad, feedstock cover)[1,2]	$11,075	$0	$0	$0	$0	$11,075	$11,075
Upgrade of grid interconnection (buses, disconnects)[3]	$25,000	$0	$0	$0	$0	$25,000	$25,000
Annual lease of gasifier (5-year fixed price)[4]	$108,000	$108,000	$108,000	$108,000	$108,000	$540,000	$528,376
Annual O&M of gasifier (SCWA staff)[5]	$23,600	$24,072	$24,553	$25,045	$25,545	$122,815	$120,120
Periodic rebuild of gasifier genset engine[6]	$0	$0	$15,000	$0	$0	$15,000	$14,675
Total Cost	**$167,675**	**$132,072**	**$147,553**	**$133,045**	**$133,545**	**$713,890**	**$699,246**
Benefits							
Annual avoided PG&E electricity purchases[7]	$50,589	$52,612	$54,717	$56,905	$59,182	$274,004	$267,877
Annual avoided PG&E natural gas purchases[7]	$6,387	$6,387	$6,387	$6,387	$6,387	$31,935	$31,248
Annual excess electricity generation sold to CCA[7,8]	$47,976	$47,976	$47,976	$47,976	$47,976	$239,880	$234,716
Annual monetized value of carbon offsets[9]	$12,229	$13,452	$14,797	$16,277	$17,905	$74,660	$72,901
Total Benefit	**$117,181**	**$120,427**	**$123,877**	**$127,545**	**$131,449**	**$620,479**	**$606,741**
Net Benefit	**($50,494)**	**($11,645)**	**($23,677)**	**($5,499)**	**($2,096)**	**($93,412)**	**($92,505)**

[1]Estimated using Concrete Calculator at http://www.concretenetwork.com/concrete/howmuch/calculator.htm
[2]Estimated using Pole Barn Price Tool at http://www.carterlumber.com/Estimators/PoleBarn
[3]Based on lower bound of cost range provided by Community Power Corporation, March 2013
[4]Estimated monthly fixed-price lease rate (without maintenance) provided by Community Power Corporation, February 2013
[5]Based on 0.16 FTE provided by Community Power Corporation, February 2013 ($80,000 SCWA staff salary; $10,800 in parts; 2% annual escalation)
[6]Based on estimated outsourcing cost and 2- to 3-year rebuild schedule recommended by Community Power Corporation, March 2013
[7]Based on annual gross benefit calculated in Table 8 for base year 2014 (4% annual rate escalation for avoided PG&E electricity purchases only)
[8]Based on fixed CCA purchase price of $0.116/kWh (using Marin Clean Energy baseload facility contract price with 20-year delivery term as proxy)
[9]Based on settlement price from California Air Resources Board quarterly GHG allowances auction, August 2013 (10% annual price escalation)

Note: Net Present Value calculated using a 1.1% nominal discount rate over 4 years as directed by OMB Circular A-94, Appendix C

Table F-1B. 5-year gasifier lease model: Airport WWTP

	2014	2015	2016	2017	2018	Total	NPV
Costs							
Site preparation (concrete pad, feedstock cover)[1,2]	$11,075	$0	$0	$0	$0	$11,075	$11,075
Upgrade of grid interconnection (buses, disconnects)[3]	$25,000	$0	$0	$0	$0	$25,000	$25,000
Annual lease of gasifier (5-year fixed price)[4]	$108,000	$108,000	$108,000	$108,000	$108,000	$540,000	$528,376
Annual O&M of gasifier (SCWA staff)[5]	$23,600	$24,072	$24,553	$25,045	$25,545	$122,815	$120,120
Periodic rebuild of gasifier genset engine[6]	$0	$0	$15,000	$0	$0	$15,000	$14,675
Total Cost	**$167,675**	**$132,072**	**$147,553**	**$133,045**	**$133,545**	**$713,890**	**$699,246**
Benefits							
Annual avoided PG&E electricity purchases[7]	$105,638	$109,864	$114,258	$118,829	$123,582	$572,171	$559,375
Annual avoided PG&E natural gas purchases[7]	$0	$0	$0	$0	$0	$0	$0
Annual excess electricity generation sold to CCA[7,8]	$885	$885	$885	$885	$885	$4,427	$4,331
Annual monetized value of carbon offsets[9]	$11,481	$12,629	$13,892	$15,281	$16,810	$70,094	$68,443
Total Benefit	**$118,005**	**$123,378**	**$129,036**	**$134,996**	**$141,277**	**$646,692**	**$632,149**
Net Benefit	**($49,670)**	**($8,694)**	**($18,517)**	**$1,951**	**$7,731**	**($67,199)**	**($67,097)**

[1]Estimated using Concrete Calculator at http://www.concretenetwork.com/concrete/howmuch/calculator.htm
[2]Estimated using Pole Barn Price Tool at http://www.carterlumber.com/Estimators/PoleBarn
[3]Based on lower bound of cost range provided by Community Power Corporation, March 2013
[4]Estimated monthly fixed-price lease rate (without maintenance) provided by Community Power Corporation, February 2013
[5]Based on 0.16 FTE provided by Community Power Corporation, February 2013 ($80,000 SCWA staff salary; $10,800 in parts; 2% annual escalation)
[6]Based on estimated outsourcing cost and 2- to 3-year rebuild schedule recommended by Community Power Corporation, March 2013
[7]Based on annual gross benefit calculated in Table 8 for base year 2014 (4% annual rate escalation for avoided PG&E electricity purchases only)
[8]Based on fixed CCA purchase price of $0.116/kWh (using Marin Clean Energy baseload facility contract price with 20-year delivery term as proxy)
[9]Based on settlement price from California Air Resources Board quarterly GHG allowances auction, August 2013 (10% annual price escalation)

Note: Net Present Value calculated using a 1.1% nominal discount rate over 4 years as directed by OMB Circular A-94, Appendix C

Table F-1C. 5-year gasifier lease model: R-4 Pump Station

	2014	2015	2016	2017	2018	Total	NPV
Costs							
Site preparation (concrete pad, feedstock cover)[1,2]	$11,075	$0	$0	$0	$0	$11,075	$11,075
Upgrade of grid interconnection (buses, disconnects)[3]	$25,000	$0	$0	$0	$0	$25,000	$25,000
Annual lease of gasifier (5-year fixed price)[4]	$108,000	$108,000	$108,000	$108,000	$108,000	$540,000	$528,376
Annual O&M of gasifier (SCWA staff)[5]	$23,600	$24,072	$24,553	$25,045	$25,545	$122,815	$120,120
Periodic rebuild of gasifier genset engine[6]	$0	$0	$15,000	$0	$0	$15,000	$14,675
Total Cost	**$167,675**	**$132,072**	**$147,553**	**$133,045**	**$133,545**	**$713,890**	**$699,246**
Benefits							
Annual avoided PG&E electricity purchases[7]	$76,601	$79,665	$82,852	$86,166	$89,612	$414,895	$405,616
Annual avoided PG&E natural gas purchases[7]	$0	$0	$0	$0	$0	$0	$0
Annual excess electricity generation sold to CCA[7,8]	$35,231	$35,231	$35,231	$35,231	$35,231	$176,156	$172,364
Annual monetized value of carbon offsets[9]	$11,481	$12,629	$13,892	$15,281	$16,810	$70,094	$68,443
Total Benefit	**$123,313**	**$127,526**	**$131,975**	**$136,678**	**$141,653**	**$661,145**	**$646,424**
Net Benefit	**($44,362)**	**($4,546)**	**($15,578)**	**$3,634**	**$8,108**	**($52,745)**	**($52,822)**

[1]Estimated using Concrete Calculator at http://www.concretenetwork.com/concrete/howmuch/calculator.htm
[2]Estimated using Pole Barn Price Tool at http://www.carterlumber.com/Estimators/PoleBarn
[3]Based on lower bound of cost range provided by Community Power Corporation, March 2013
[4]Estimated monthly fixed-price lease rate (without maintenance) provided by Community Power Corporation, February 2013
[5]Based on 0.16 FTE provided by Community Power Corporation, February 2013 ($80,000 SCWA staff salary; $10,800 in parts; 2% annual escalation)
[6]Based on estimated outsourcing cost and 2- to 3-year rebuild schedule recommended by Community Power Corporation, March 2013
[7]Based on annual gross benefit calculated in Table 8 for base year 2014 (4% annual rate escalation for avoided PG&E electricity purchases only)
[8]Based on fixed CCA purchase price of $0.116/kWh (using Marin Clean Energy baseload facility contract price with 20-year delivery term as proxy)
[9]Based on settlement price from California Air Resources Board quarterly GHG allowances auction, August 2013 (10% annual price escalation)

Note: Net Present Value calculated using a 1.1% nominal discount rate over 4 years as directed by OMB Circular A-94, Appendix C

Table F-2A. 11-year gasifier lease model: 404 Aviation Boulevard

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total	NPV
Costs													
Site preparation (concrete pad, feedstock cover)[1,2]	$11,075	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,075	$11,075
Upgrade of grid interconnection (buses, disconnects)[3]	$25,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,000	$25,000
Annual lease of gasifier (5-year fixed; 3-year options)[4]	$108,000	$108,000	$108,000	$108,000	$108,000	$113,000	$113,000	$113,000	$116,000	$116,000	$116,000	$1,227,000	$1,111,525
Annual O&M of gasifier (SCWA staff)[5]	$23,600	$24,072	$24,553	$25,045	$25,545	$26,056	$26,577	$27,109	$27,651	$28,204	$28,768	$287,182	$259,600
Periodic rebuild of gasifier genset engine[6]	$0	$0	$15,000	$0	$0	$15,000	$0	$0	$15,000	$0	$0	$45,000	$40,806
Total Cost	**$167,675**	**$132,072**	**$147,553**	**$133,045**	**$133,545**	**$154,056**	**$139,577**	**$140,109**	**$158,651**	**$144,204**	**$144,768**	**$1,595,257**	**$1,448,006**
Benefits													
Annual avoided PG&E electricity purchases[7]	$50,589	$52,612	$54,717	$56,905	$59,182	$61,549	$64,011	$66,571	$69,234	$72,003	$74,884	$682,256	$614,370
Annual avoided PG&E natural gas purchases[7]	$6,387	$6,387	$6,387	$6,387	$6,387	$6,387	$6,387	$6,387	$6,387	$6,387	$6,387	$70,257	$63,759
Annual excess electricity generation sold to CCA[7,8]	$47,976	$47,976	$47,976	$47,976	$47,976	$47,976	$47,976	$47,976	$47,976	$47,976	$47,976	$527,735	$478,924
Annual monetized value of carbon offsets[9]	$12,229	$13,452	$14,797	$16,277	$17,905	$19,695	$20,680	$21,714	$22,799	$23,939	$25,136	$208,624	$186,735
Total Benefit	**$117,181**	**$120,427**	**$123,877**	**$127,545**	**$131,449**	**$135,607**	**$139,053**	**$142,648**	**$146,396**	**$150,306**	**$154,383**	**$1,488,872**	**$1,343,787**
Net Benefit	**($50,494)**	**($11,645)**	**($23,677)**	**($5,499)**	**($2,096)**	**($18,450)**	**($524)**	**$2,539**	**($12,255)**	**$6,102**	**$9,615**	**($106,385)**	**($104,219)**

[1]Estimated using Concrete Calculator at http://www.concretenetwork.com/concrete/howmuch/calculator.htm
[2]Estimated using Pole Barn Price Tool at http://www.carterlumber.com/Estimators/PoleBarn
[3]Based on lower bound of cost range provided by Community Power Corporation, March 2013
[4]Estimated monthly fixed-price lease rate (without maintenance) provided by Community Power Corporation, February 2013
[5]Based on 0.16 FTE provided by Community Power Corporation, February 2013 ($80,000 SCWA staff salary; $10,800 in parts; 2% annual escalation)
[6]Based on estimated outsourcing cost and 2- to 3-year rebuild schedule recommended by Community Power Corporation, March 2013
[7]Based on annual gross benefit calculated in Table 8 for base year 2014 (4% annual rate escalation for avoided PG&E electricity purchases only)
[8]Based on fixed CCA purchase price of $0.116/kWh (using Marin Clean Energy baseload facility contract price with 20-year delivery term as proxy)
[9]Based on settlement price from California Air Resources Board quarterly GHG allowances auction, August 2013 (10% annual price escalation for 5 years; 5% thereafter)

Note: Net Present Value calculated using a 2.0% nominal discount rate over 10 years as directed by OMB Circular A-94, Appendix C

Table F-2B. 11-year gasifier lease model: Airport WWTP

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total	NPV
Costs													
Site preparation (concrete pad, feedstock cover)[1,2]	$11,075	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,075	$11,075
Upgrade of grid interconnection (buses, disconnects)[3]	$25,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,000	$25,000
Annual lease of gasifier (5-year fixed; 3-year options)[4]	$108,000	$108,000	$108,000	$108,000	$108,000	$113,000	$113,000	$113,000	$116,000	$116,000	$116,000	$1,227,000	$1,111,525
Annual O&M of gasifier (SCWA staff)[5]	$23,600	$24,072	$24,553	$25,045	$25,545	$26,056	$26,577	$27,109	$27,651	$28,204	$28,768	$287,182	$259,600
Periodic rebuild of gasifier genset engine[6]	$0	$0	$15,000	$0	$0	$15,000	$0	$0	$15,000	$0	$0	$45,000	$40,806
Total Cost	**$167,675**	**$132,072**	**$147,553**	**$133,045**	**$133,545**	**$154,056**	**$139,577**	**$140,109**	**$158,651**	**$144,204**	**$144,768**	**$1,595,257**	**$1,448,006**
Benefits													
Annual avoided PG&E electricity purchases[7]	$105,638	$109,864	$114,258	$118,829	$123,582	$128,525	$133,666	$139,013	$144,573	$150,356	$156,370	$1,424,675	$1,282,916
Annual avoided PG&E natural gas purchases[7]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual excess electricity generation sold to CCA[7,8]	$885	$885	$885	$885	$885	$885	$885	$885	$885	$885	$885	$9,739	$8,838
Annual monetized value of carbon offsets[9]	$11,481	$12,629	$13,892	$15,281	$16,810	$18,491	$19,415	$20,386	$21,405	$22,475	$23,599	$195,865	$175,315
Total Benefit	**$118,005**	**$123,378**	**$129,036**	**$134,996**	**$141,277**	**$147,901**	**$153,967**	**$160,284**	**$166,864**	**$173,717**	**$180,855**	**$1,630,279**	**$1,467,069**
Net Benefit	**($49,670)**	**($8,694)**	**($18,517)**	**$1,951**	**$7,731**	**($6,155)**	**$14,389**	**$20,175**	**$8,213**	**$29,513**	**$36,087**	**$35,022**	**$19,063**

[1]Estimated using Concrete Calculator at http://www.concretenetwork.com/concrete/howmuch/calculator.htm
[2]Estimated using Pole Barn Price Tool at http://www.carterlumber.com/Estimators/PoleBarn
[3]Based on lower bound of cost range provided by Community Power Corporation, March 2013
[4]Estimated monthly fixed-price lease rate (without maintenance) provided by Community Power Corporation, February 2013
[5]Based on 0.16 FTE provided by Community Power Corporation, February 2013 ($80,000 SCWA staff salary; $10,800 in parts; 2% annual escalation)
[6]Based on estimated outsourcing cost and 2- to 3-year rebuild schedule recommended by Community Power Corporation, March 2013
[7]Based on annual gross benefit calculated in Table 8 for base year 2014 (4% annual rate escalation for avoided PG&E electricity purchases only)
[8]Based on fixed CCA purchase price of $0.116/kWh (using Marin Clean Energy baseload facility contract price with 20-year delivery term as proxy)
[9]Based on settlement price from California Air Resources Board quarterly GHG allowances auction, August 2013 (10% annual price escalation for 5 years; 5% thereafter)

Note: Net Present Value calculated using a 2.0% nominal discount rate over 10 years as directed by OMB Circular A-94, Appendix C

Table F-2C. 11-year gasifier lease model: R-4 Pump Station

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total	NPV
Costs													
Site preparation (concrete pad, feedstock cover)[1,2]	$11,075	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,075	$11,075
Upgrade of grid interconnection (buses, disconnects)[3]	$25,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$25,000	$25,000
Annual lease of gasifier (5-year fixed; 3-year options)[4]	$108,000	$108,000	$108,000	$108,000	$108,000	$113,000	$113,000	$113,000	$116,000	$116,000	$116,000	$1,227,000	$1,111,525
Annual O&M of gasifier (SCWA staff)[5]	$23,600	$24,072	$24,553	$25,045	$25,545	$26,056	$26,577	$27,109	$27,651	$28,204	$28,768	$287,182	$259,600
Periodic rebuild of gasifier genset engine[6]	$0	$0	$15,000	$0	$0	$15,000	$0	$0	$15,000	$0	$0	$45,000	$40,806
Total Cost	**$167,675**	**$132,072**	**$147,553**	**$133,045**	**$133,545**	**$154,056**	**$139,577**	**$140,109**	**$158,651**	**$144,204**	**$144,768**	**$1,595,257**	**$1,448,006**
Benefits													
Annual avoided PG&E electricity purchases[7]	$76,601	$79,665	$82,852	$86,166	$89,612	$93,197	$96,925	$100,802	$104,834	$109,027	$113,388	$1,033,067	$930,274
Annual avoided PG&E natural gas purchases[7]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Annual excess electricity generation sold to CCA[7,8]	$35,231	$35,231	$35,231	$35,231	$35,231	$35,231	$35,231	$35,231	$35,231	$35,231	$35,231	$387,544	$351,699
Annual monetized value of carbon offsets[9]	$11,481	$12,629	$13,892	$15,281	$16,810	$18,491	$19,415	$20,386	$21,405	$22,475	$23,599	$195,865	$175,315
Total Benefit	**$123,313**	**$127,526**	**$131,975**	**$136,678**	**$141,653**	**$146,919**	**$151,571**	**$156,419**	**$161,470**	**$166,734**	**$172,219**	**$1,616,476**	**$1,457,288**
Net Benefit	**($44,362)**	**($4,546)**	**($15,578)**	**$3,634**	**$8,108**	**($7,138)**	**$11,994**	**$16,310**	**$2,819**	**$22,529**	**$27,450**	**$21,219**	**$9,282**

[1]Estimated using Concrete Calculator at http://www.concretenetwork.com/concrete/howmuch/calculator.htm
[2]Estimated using Pole Barn Price Tool at http://www.carterlumber.com/Estimators/PoleBarn
[3]Based on lower bound of cost range provided by Community Power Corporation, March 2013
[4]Estimated monthly fixed-price lease rate (without maintenance) provided by Community Power Corporation, February 2013
[5]Based on 0.16 FTE provided by Community Power Corporation, February 2013 ($80,000 SCWA staff salary; $10,800 in parts; 2% annual escalation)
[6]Based on estimated outsourcing cost and 2- to 3-year rebuild schedule recommended by Community Power Corporation, March 2013
[7]Based on annual gross benefit calculated in Table 8 for base year 2014 (4% annual rate escalation for avoided PG&E electricity purchases only)
[8]Based on fixed CCA purchase price of $0.116/kWh (using Marin Clean Energy baseload facility contract price with 20-year delivery term as proxy)
[9]Based on settlement price from California Air Resources Board quarterly GHG allowances auction, August 2013 (10% annual price escalation for 5 years; 5% thereafter)

Note: Net Present Value calculated using a 2.0% nominal discount rate over 10 years as directed by OMB Circular A-94, Appendix C