Title
UCSD Biomass to Power Economic Feasibility Study

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UCSD Biomass to Power

Economic Feasibility Study

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UCSD Biomass to Power - Feasibility Study

Executive Summary

This report examines the economic and technical feasibility of using separated biomass feedstock from the Miramar Landfill, located in San Diego County, to generate 3 MW of power. The process will utilize gasification technology provided by West Biofuels, LLC. The objective of the study is to determine the economics of the proposed biomass power system in terms of the potential revenue streams and operational costs. The goal of this study is to determine whether this project has a positive net present value (NPV) based on the site specific parameters associated with the Miramar Landfill.

This report begins with background information and a description of the biomass to energy conversion process. Next, it details the major economic considerations including feedstock, capital, and operating costs. Regulatory issues, inclusive of production credits, renewable energy incentives, and feed-in tariffs are then addressed since these are also significant economic inputs. All of these inputs are then combined into three scenarios, two of which are specific to utilizing separated biomass from the Miramar landfill, with the third a generic site with optimized parameters. Finally, sensitivity analyses are performed to demonstrate how changes in scaling of the biomass power plant and the economic inputs influence the feasibility of a potential project.

A team from UCSD's Jacobs School of Engineering and Rady School of Management found that a 3MW facility sited on the Miramar landfill and/or utilizing Miramar sourced biomass would be difficult to justify. In order to develop a project, numerous economic and non-economic challenges would need to be addressed, including siting, scaling, feedstock availability, locating a suitable waste heat customer, and/or finding a power customer willing to purchase electricity at above market rates.

Background

Historical: The Miramar Landfill had been scheduled to close operations in 2011. However, recently this date has been extended to 2017 due to an increase in permitted capacity. Recently, the city of San Diego has begun to take other steps to extend the life of the landfill through diversion and/or conversion methods. The feedstock opportunity is substantial—more than 1.4 million tons of waste is disposed of at the Miramar Landfill every year. At this environmentally secure, lined landfill, the City's refuse is covered on a daily basis in conformance with regulatory and environmental requirements. Closed areas of the landfill are revegetated with native plants cultivated in the Landfill Nursery. High quality mulch, compost and wood chips are made at the Miramar Greenery, and are available to the public. Due to this significant feedstock availability, a significant component of this study involves determining whether or not citing at Miramar is a viable option.

Stakeholders: EnXco is a potential owner/operator of the proposed facility. EnXco, partially owned by a division of Electricity de France, is currently developing wind power and photo voltaic projects throughout the US and also investigating emerging technologies, such as biomass to power projects. UCSD is a stakeholder in this project on two levels. First, the university is a potential power customer. As part of the development of a UC-wide environmentally sustainable energy mandate, UCSD is exploring sources of alternative energies and is a potential customer for the entire 3 MW proposed biomass power project. Secondly, UCSD views the development of a biomass power production facility at Miramar as an opportunity to pursue educational and research objectives. West Biofuels is pioneering the gasification technology that has been proposed for this study. As a biomass to liquid fuel company, West Biofuels aims to apply its gasification technology to the co-generation of power in this scenario without biomass to liquid fuels production. A new research effort involving three University of California campuses and West Biofuels LLC, will develop a prototype research reactor that will use steam, sand and catalysts to efficiently convert forest, urban, and agricultural "cellulosic" wastes that would otherwise go to landfills into alcohol that can be used as a gasoline additive.

Technical: Thermal gasification is the chemical conversion at high temperatures of materials containing carbon atoms into a synthetic gas (syngas). This syngas can be used to manufacture chemicals, and because it is combustible, it can also be used as a fuel in place of natural gas for electric generation. The gasification technology relies on chemical reactions that breakdown cellulosic green waste, or more broadly, municipal solid waste (MSW) into simpler molecules. This is in contrast to incineration, a process that creates more complex substances. Based on the report prepared for Alameda Power and Telecom entitled, "Investigation into Municipal Solid Waste Gasification for Power Generation," we recognize that electric generation using thermal gasification is a viable technology[1]. The technology uses three processing stages to produce electricity from refuse. Each of these sub-processes has been used for decades in applications similar to green waste or MSW gasification and energy production. Combining them into a single integrated process to gasify green waste for power is new and viable, however it is not a mature application. Therefore, early commercial developments need to incorporate appropriate risk mitigation strategies. The most effective risk mitigation measure for a municipal utility is to contract for power from a project without taking on the risk of ownership until a project has demonstrated its reliability. Therefore, there is an opportunity to develop a project using this technology.

Financial: Previous studies have shown that the economics of thermal gasification of waste are highly dependent on the costs for alternative base load power and the cost of disposing of waste in landfills. A thermal waste gasification power generation facility obtains its primary revenues by operating in two markets. First, the project sells its primary product of base load electricity under a long-term contract with the buyer. In order to be attractive, the price of the project receives for its energy must be competitive with market prices for base load electricity. Unlike any other types of power generation,

[1] 2004. Advanced Energy Strategies, Inc., "Investigation into Municipal Solid Waste Gasification for Power Generation."

the thermal gasification facility makes its own fuel (synthetic gas) from material it may or may not be paid to accept. A second potential source of revenue is the tipping fees paid by haulers that would have otherwise transported the waste to landfills. The natural upper limit of these revenues is the amount haulers would otherwise pay to dispose of this waste in a landfill. Alternatively, waste used as a feedstock may be an expense to a gasification facility operator rather than a revenue source. This situation may be more likely if the waste handler has alternate uses for the waste allowing them to command a price rather than a tipping fee.

Process Description

The process modeled for this study begins when biomass is contacted with steam at high temperature in order to produce a fuel gas. This gas is composed mainly of hydrogen, carbon monoxide, methane and carbon dioxide. Next, the fuel gas is burned in an internal combustion engine which turns an electrical generator. Energy in the hot exhaust gases can be captured to provide process heat or heat for export.

The reactions involved in gasification of biomass to produce fuel gas and synthesis gas are endothermic. That is, they require a net input of energy. The energy required is obtained by oxidizing (burning) a portion of the biomass in exothermic reactions. The overall process is exothermic. In some plant designs, both the gasification and oxidation reactions are carried out in different sections of the same reaction chamber. Such a process is referred to as a directly heated gasifier. Control of the movement of biomass through different sections of the reaction chamber in a directly heated gasifier can be problematic.

In contrast, the process described here uses an indirectly heated gasifier. Two reactors are used: one in which the endothermic gasification reactions occur and one in which the exothermic oxidation reactions occur. Gas-fluidized sand in the reactors circulates between the two reactors, carrying char from the gasifier to the char combustor and heat from the char combustor back to the gasifier. Such dual fluidized bed processes were developed in World War II to produce high octane gasoline and are used extensively today in the petroleum refining industry. One advantage of this design is that the fuel gas does not contain inert nitrogen since the gasification reaction occurs in the absence of oxygen or air and, thus, has a higher heating value than the gas from a directly heated gasifier.

In the Figure 1 below, wet biomass is dried in the Drier (S-10) by contact with air mixed with part of the hot exhaust stream of the Char Combustor (R-2). The biomass is dried to a controlled moisture content in order to provide a consistent input to the gasifier. Dried biomass is contacted with steam and hot fluidized sand in the Gasifier (R-1). The biomass reacts with steam and is converted into product gas and solid char. Fluidized sand and char from the Gasifier flows to the Char Combustor where the char is burned with air to produce exhaust gas and heated sand. The hot fluidized sand flows back to the Gasifer and provides energy for the endothermic gasification reactions.

Product gas leaving the Gasifier is cooled in heat exchangers H-1 and H-2. Water condensed from this gas is separated in flash drum S-2. The product gas is filtered in Filter S-3, and then fed to the engine-generator set. The product gas fed to the engine is composed of hydrogen, carbon monoxide, methane, and other hydrocarbons. A small portion of the electrical output of the generator is required for operation of plant equipment such as water pumps and air blowers. Not shown is optional equipment to capture waste heat from the engine exhaust.

Exhaust gas leaving the Char Combustor is composed of nitrogen, oxygen, and carbon dioxide. The gas is split, with one fraction going to heat the air to the biomass drier and the other fraction cooled in heat exchanger H-3 and filtered by Filter S-4 before leaving the plant.

Steam fed to the Gasifier is produced by heating water with the hot product gas in heat exchangers H-1 and H-2. Cooling water circulates through H-2 in a loop through an evaporative cooler (M-1). Water required to make steam for the Gasifier is drawn from this loop and sent through heat exchanger H-2. Makeup water to replace this draw is obtained by condensing water from the exhaust air from the wet biomass drier in flash drum S-5. Any additional makeup water required is obtained as feed to the plant from the city mains.

Ash from the Char Combustor and from the filters leaves the plant. Not shown in the process schematic is fluidization sand makeup, which is required to replace fine sand leaving the plant with the ash. (Please see Appendix A for a photograph of the gasification equipment and a simplified flow diagram)

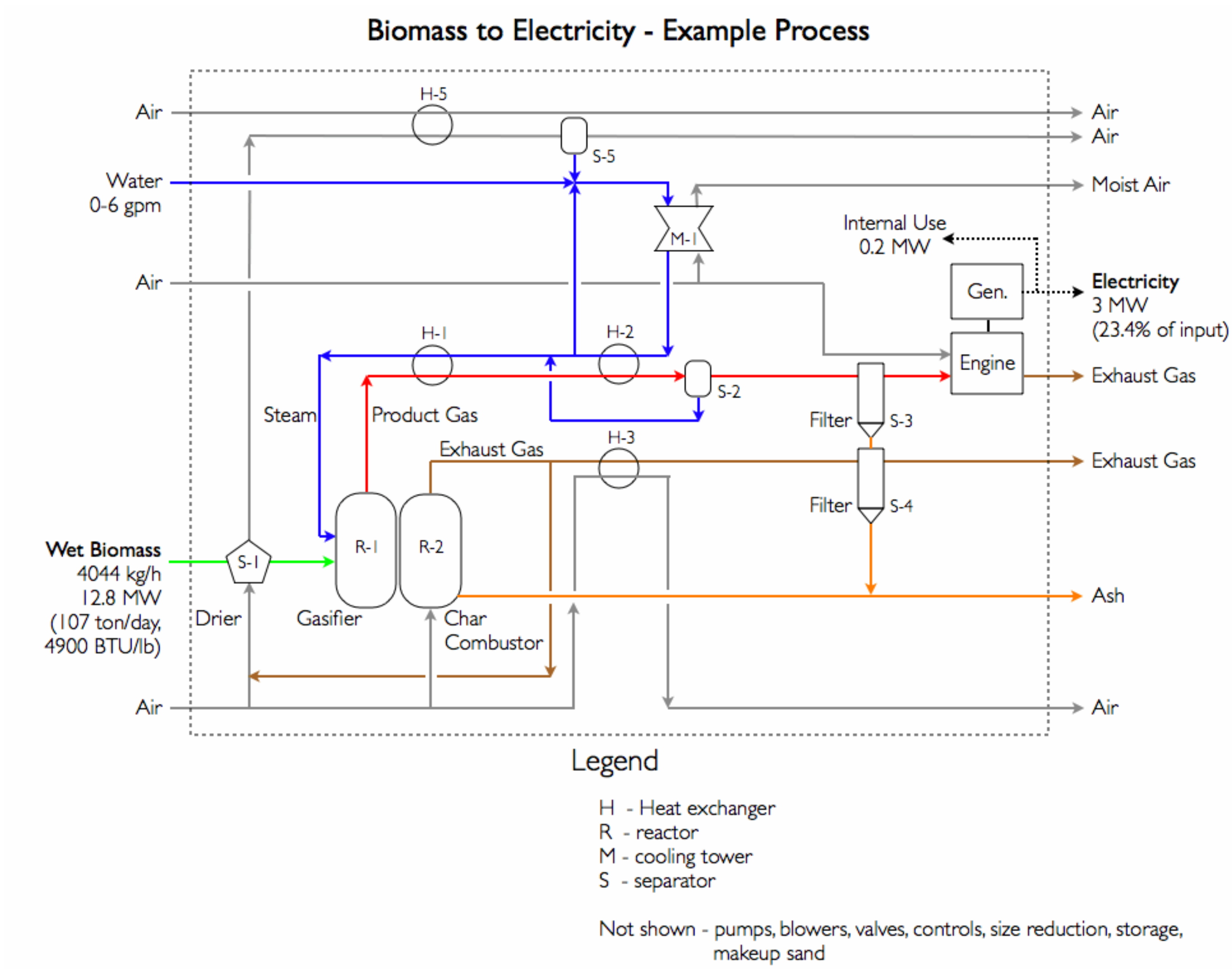

Figure 1: West Biofuels Biomass Gasification to Power Process

Feedstocks

Feedstock cost and availability represent some of the most critical aspects of any gasification project, with cost and contract considerations being the most important. The market for feedstock varies greatly depending on both the region and uses (current or expected) for the material being considered. This study focuses on using separated biomass feedstock from the Miramar Landfill.

Availability: Approximately 20% of the waste generated in the city of San Diego is organic waste, excluding organic waste classified as construction and demolition waste[2]. Of the residential waste in the Miramar Landfill, more than 14% of this is recyclable green material. Currently there is approximately 100,000 tons per year that is diverted to the Miramar Greenery in order to produce mulch, compost and wood chips that are available to the public. This is an important program designed in part to prolong the life of the landfill. The City of San Diego is planning on expanding the capacity of the Greenery to 150,000 tons per year by April of 2009. On top of this, there is an additional 120,000 tons per year that is not separated, and thus is disposed of in the landfill each year. Of the material that is processed through the Greenery, only 5-10% of this material is currently put into the dump.

Beyond the Miramar landfill, Allied Waste Company is a private company that operates both the Sycamore Landfill (east of Miramar) and the Otay Mesa Landfill (South of Miramar). Allied has approximately 150,000-200,000 tons per year of biomass material that is used primarily as daily cover in their respective landfills. There are also several Green Waste Recyclers[3] located in San Diego County such as Agri Service Inc's El Corazon facility[4] and Organic Recycling West[5] that could also supply significant amounts of material for use as feedstock to the proposed system. The amount of feedstock required is 34,000 tons per year for a 3 MW plant or 56,000 tons per year for a 5 MW plant. Given the annual quantities of product that is taken into the various landfills and collectors, there appears to be a sufficient quantity of feedstock available to sustain our project.

Quality: With a fixed efficiency in the gasification process, the composition of the feedstock will directly impact the energy output per unit of biomass input. Feedstock quality can be measured in terms of the percentage of moisture, the percentage of ash, and the energy content, as measured by the higher heating value, of the biomass. Moisture is removed in the process and does not contribute to the energy output of the facility. Some moisture, however, is beneficial as it can be used to produce steam which is fed into the fluidized bed gasification reactor. Note that moisture is not expected to significantly impact the economics of the proposed plant since wetter biomass would likely cost less per ton; biomass is typically quoted in dollars per "bone dry ton". Therefore, the economic impact of more water in the biomass is more pre-processing, most significantly more land needed for drying biomass.

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[2] City of San Diego, Environmental Services Department, *Waste Composition Study 1999-2000,* November 2000

[3] http://www.wildfirezone.org/assets/images/resource_docs/greenwasterecyclingguide.pdf

[4] http://www.agriserviceinc.com/agriservice.html

[5] http://www.orisupplies.com/

The variation in ash content of biomass does not vary significantly for a given type of biomass (wood chips vs. processed green waste vs. compost). Furthermore, in the ranges of ash content for the types of biomass expected to be used, the percentage of ash will not significantly impact the economics of the facility.

As part of our analysis, samples were collected from the Miramar landfill. Table 1 below provides the results of testing from those samples. Note that higher heating value and percent ash test values were not available at the time of this report; literature values are reported.

Table 1: Feedstock quality of Miramar Landfill samples

Sample No.	Description	Moisture (% wet)	HHV* (BTU/dry lb)	Ash* (% dry)
1A	Processed Green Waste	44.6	7500	2-5%
1B	Processed Green Waste	46.1	7500	2-5%
1C	Processed Green Waste	45.3	7500	2-5%
2A	Large Wood Chip <2"	19.2	8000	<1%
2B	Large Wood Chip >2"	18.9	8000	<1%
3A	Small Wood Chip <2"	21.5	8000	<1%
3B	Small Wood Chip <2"	20.8	8000	<1%
4A	Green Waste Compost	65.4	6500	5-15%
4B	Green Waste Compost	63.8	6500	5-15%

Given these results and in light of the discussion above, the baseline economic model assumed moisture at 30%, ash content at 5%, and a higher heating value of 7000 BTU per dry pound. Of these assumptions, the higher heating value was determined to be both the most uncontrollable during actual operation as well as the most significant economically. Therefore, the higher heating value was chosen as a probabilistic variable in our economic model simulations with a mean of 7,000 BTU/dry lb and the 99th percentile of the distribution of this value at 8,630 BTU/dry lb (see table 4).

<u>Cost:</u> Biomass waste is increasingly becoming a commodity product. The landfill currently sells wood chips, mulch and compost to landscapers and to the public. They also sell some of this wood waste material to electricity producers such as Colmac Energy Inc.[6] Green waste recyclers including the greenery at the Miramar landfill have two sources of revenue. First they earn a disposal fee of up to $25 per ton collected[7], and secondly they charge up to $18 per cubic yard ($90 per ton) for the finished products that they sell.[8] The City of San Diego is currently conducting a competitive bid for processed

[6] http://www.aciinc.net/CEI.html
[7] http://www.sandiego.gov/environmental-services/miramar/fees.shtml
[8] http://www.sandiego.gov/environmental-services/miramar/cmw.shtml

green waste with the results being available with a request for public information. There will be three companies, including firms utilizing the green waste as input for power production, participating in the bidding process with the expected range of bids in the $15-$20 per ton range.

In interviews with landscaping and tree trimming companies that use the existing services for disposal of the waste generated during operation of their businesses, there is considerable interest in lower cost or free waste removal or drop off. This creates the potential for reduced or negative (income) feedstock costs. Additional capital and operating expenditures due to increased land and processing needs would be required. Furthermore, relying upon smaller landscaping companies for biomass input introduces greater contract risk over the required life of the project.

Contracts: It is likely that the city believes demand for the landfill biomass will increase in the future. The City is also hesitant to enter into long term contracts due to previous contracts that have proven disadvantageous. Consequently, the city is looking to sell green waste under one year contracts with options for up to 5 one year extensions. These contract terms are a major disincentive toward investments that depend upon a secure supply of feedstock over a project life of up to 20 years. It should be noted, however, that these terms are less onerous for existing facilities, either dedicated biomass or co-fired biomass plants, where power generation assets are pre-existing. Therefore, the city may be successful in securing contracts under its expected prices and terms. In addition to unfavorable contract terms, and the high price of the biomass from the Miramar landfill, there is a high level of competition for feedstock relative to other locations in California.

Competition

As discussed in the feedstock section above, biomass waste is increasingly becoming a commodity product, particularly as an input to biomass power plants. As will be described in the incentive and feed-in tariff sections of this paper, there is more certainty around the demand and pricing for renewable power than there is in the market for biomass feedstock. Therefore, competition to the proposed biomass to power facility plays out more in the acquisition of reliable, cost effective feedstock supply. Miramar landfill management indicated they have already been contacted by three companies interested in using their green waste as feedstock for power production. This interest has likely contributed to their belief that demand for landfill biomass is growing.

The importance of biomass feedstock becomes evident in an analysis of competitor activity. Envirepel, a San Diego based developer, owner and operator of biomass power facilities, has 16.5MW under contract with SDG&E at various sites in San Diego county, including the Ramona landfill, a source of feedstock. Furthermore, Envirepel has a proposal in front of SDG&E for 240MW of additional capacity, including a 90MW plant to be located in Fallbrook utilizing agricultural green waste. Envirepel has formed a strategic partnership with Allied Waste Industries, the owner and operator of the Sycamore and Otay Mesa landfills. Beyond Envirepel, Bull Moose, LLC has contracted with SDG&E for a 20MW facility.

Similar to Envirepel's strategy to secure biomass, Bull Moose has located in close proximity to Organic Recycling West in the southern end of San Diego county, and presumably has arranged for secure supply of feedstock. Taking together the input from the Miramar landfill personnel and the actions of competitors, it becomes clear that securing long-term, reliable, and cost effective supply of feedstock is key component in developing a viable biomass power project.

As a final note, the simple economics of supply and demand lead to the expectation that areas with greater supply of biomass, such as northern California with a higher density of both forests and agriculture, may be more conducive to an investment in a biomass power plant. Simply, these areas of higher supply will enable biomass to be secured under long-term contracts at better prices.

Capital Costs

The investment in equipment and facilities included in this feasibility analysis assumes constant output (3MW in the base analysis case) with operations 24/7 throughout the year with all installed hardware aimed for full utilization. It is further assumed that the biomass feedstock is pre-chipped and no chipping equipment is required. Detailed evaluation of peaking operation was not conducted. Note that the technology employed allows for the possibility of liquefying the output from the gasifier during the night while burning this liquid fuel and producer gas during the day at higher power production rates. The trade-offs of such liquification including the benefits (capturing additional peak power pricing) and costs (additional capital costs in gasifier and engine-generator sets) was also not analyzed.

Facility Cost: The capital costs for the facility components were estimated by the project collaborators. The table below describes the values assumed:

Table 2: Capital Costs

Component	Cost	Source
Gasification System (includes combustor and gas cleaning system)	$6,000,000	Robert Cattolica - UCSD, Matthew Summers - West Biofuels
Engine and Generator Sets	$750/KW installed	Gonzalo Stabile - enXco

Assuming the aforementioned, total facility capital costs for the West Biofuels/UCSD 3 MW gross electrical capacity system is $8,375,000. Note that in analyses including capturing waste heat for export, an addition $150/KW was added for heat recovery equipment. Accounting for parasitic load, this translates to a cost of $2,849 per KW. Included in this complete system cost are both the gasification and combustion system along with the reciprocating engines and generators. Scaling the system up from the base 3 MW capacity to a maximum of 5 MW, the following costs are observed to exhibit a gradual reduction in cost per KW of net electrical capacity[9]:

Table 3: Capital Costs versus Capacity

Capacity	Facility CapEx	$/KW-net
3 MW	$8,375,000	2,849
4 MW	$10,058,780	2,566
5 MW	$11,631,713	2,374

<u>Comparisons:</u> The facility capital costs and scaling results are consistent with expectations. The principal investigator on West Biofuels/UCSD biomass-to-power project, Robert Cattolica, expects a measurable cost difference when compared to a biomass-to-liquid fuel facility. Because the power project does not require equipment for Fischer-Tropsch conversion of synthesis gas into liquid, the lower cost power generation equipment translates to a reduction in capital outlay. For comparison to the 3 MW facility in this study, the similarly sized gasification system considered for the biomass-to-liquid fuel facility evaluated by Teotl Energy and targeted for Placer County, California, totaled $10,000,000.[10]

For another comparison, a 2 MW demonstration biomass-to-power facility in Güssing, Austria, is considered. In this comparison, it is assumed that the wood chip feedstock biomass utilized in the Güssing plant has the same higher heating values as the feedstock anticipated for the West Biofuels/UCSD 3 MW facility. In 2004, Hofbauer, Rauch, and Bosch reported that the Güssing plant, capable of producing 2 MW of electrical power and 4.5 MW of thermal power, cost a total of €10,000,000.[11] The West Biofuels/UCSD plant considered in this report is capable of producing 3 MW of electrical power and 4.9 MW of thermal power. Therefore, the installed cost per KW for the 3 MW plant under consideration is lower than the precedent set in Güssing, supporting an argument that West Biofuels/UCSD plant is capital efficient.

Furthermore, in 2004, Alameda County, California, commissioned an investigation into municipal solid waste gasification for power generation. Although the MSW biomass-to-power systems evaluated in the investigation were required to produce between 12 MW and 20 MW of electrical power and could not rely on a homogeneous feedstock as does the West Biofuels/UCSD 3 MW system under consideration, it is still reasonable to compare the systems. It's important to emphasize, however, that the purpose of

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[9] Gasifier capital costs were scaled with the square root of the ratio of capacity, while engine-generator sets were scaled linearly (per Matthew Summers - West Biofuels)

[10] Teotl Energy Partners LLC, *West Biofuels Biomass-to-Fuels Gasification & Blending Project, Placer County, CA, Feasibility Study*, January 19, 2007

[11] 2004. Hofbauer, Rauch, and Bosch, "Biomass CHP-Plant Güssing, A Success Story."

this comparison is to illustrate that the 3 MW facility capital costs are within ranges which are at or below those of other biomass-to-power projects and is not intended for a true comparison. For a more in-depth study, the specifics of the projects must be compared on a one-to-one basis. For example, in the Alameda comparison projects, the estimated costs for site acquisition, permitting, interest during construction, and owner's costs are included in the reported capital costs whereas in the West Biofuels/UCSD facility cost reported in this section, they are not. Despite the known issues in comparing the Alameda projects to the West Biofuels/UCSD project, and given the large difference in facility electrical capacity, it is still noteworthy that the 3 MW facility has a lower cost per KW of net electrical capacity. The results of the Alameda County investigation show that the capital cost per kW of net electric generation varies from $3,700 to $7,600 compared to the West Biofuels/UCSD 3 MW facility value of $2849.[12]

Operating costs

Figure 2 shows the breakdown of operating expenses associated with a 3MW facility, excluding feedstock costs. All expenses were assumed to escalate at a general inflation rate of 2.1% per annum.

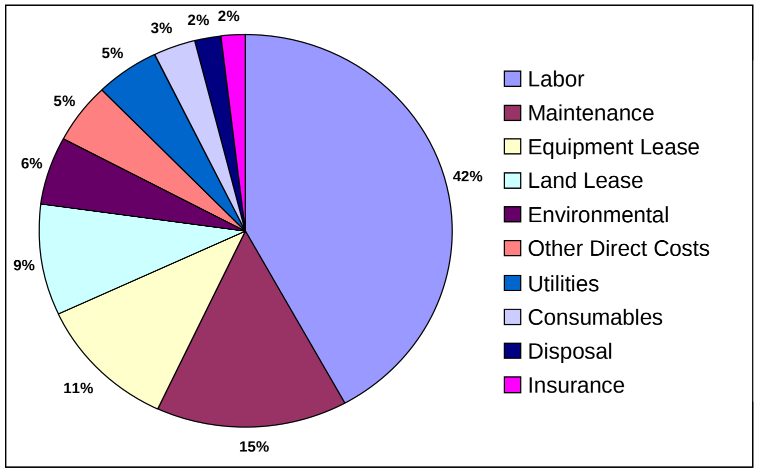

Figure 2: Operating Costs (excluding feedstock costs)

Labor: Labor costs constitute the largest annual operating costs excluding biomass feedstock costs. Operations are assumed to take place 24 hours per day, 7 days per week.

Annual labor cost, itemized by job function and including assumptions on benefits and burden rates, are shown in **Appendix B**. The number of employees was set at seven based upon guidance from several sources. The salaries used were verified from online resources[13].

A range of guidance on labor costs indicates that some uncertainty exists in these cost estimates. EnXco provided guidance that this type of facility should have six employees, which would result in lower labor costs. As calculated in the appendix, the average number of labor hours per day is 40 while the average cost per man-hour is $32.07. This compares to higher corresponding values in the West Biofuels' Placer County feasibility study[14] of 48 man-hours per day and $35 per man-hour respectively, but both values are within 20%. As a result of the magnitude in labor costs, as well as the uncertainty previously described, the labor cost input was chosen as a factor for subsequent sensitivity analyses, varying total annual labor costs by ±20%

[12] 2004. Advanced Energy Strategies, Inc., "Investigation into Municipal Solid Waste Gasification for Power Generation."
[13] www.salary.com
[14] Teotl Energy Partners LLC, *West Biofuels Biomass-to-Fuels Gasification & Blending Project, Placer County, CA, Feasibility Study*, January 19, 2007

For subsequent analyses on the feasibility of a larger scale plant, specifically 5 MW, it was assumed that no additional labor would need to be added.

Maintenance: Annual maintenance costs, specifically for maintenance parts/materials as well as for contracted labor if needed, are the second largest operating costs. The maintenance costs are shown in **Appendix C.** Guidance on maintenance was provided by EnXco at $7.00/MWh, which equates to 2% of the estimated capital costs. This estimate is within 2% of the maintenance costs estimated in West Biofuels Placer County study. Significantly, this excludes labor needed for most of the anticipated maintenance. Maintenance work will be conducted by the plant operating staff whose costs are accounted for separately. Also, replacement bed material, corrosion inhibitors, and other consumables are budgeted separately and are not part of this maintenance budget. Finally, as typically done for investment analyses in capital projects, the maintenance budget is an annual amortization of costs which are expected to vary year to year. Certain years may have very little maintenance expenses while other years may include significant activity and expense such as major engine overhauls.

Equipment Lease: The next largest operating cost category is lease costs on feedstock handling equipment, including a loader, bulldozer, and grapple, as shown in **Appendix D**. It is assumed that feedstock providers haul biomass to the gasifier site and therefore no costs associated with trucking feedstocks, such as truck leases, are included except in the business case of locating the gasifier on MCAS Miramar. Similarly, it is assumed that services to haul away residual ash are contracted.

Land Lease: Due to height restrictions on the Miramar landfill site, locating the proposed gasifier on the landfill is not possible[15]**.** For the purposes of this model, an annual cost of $100,000 was assumed for the Miramar landfill case. Lower costs were assumed for the other scenarios modeled. Note that while it may be typical for land to be provided at no charge by a host organization (i.e. landfill) in exchange for the provision of power, the scenarios modeled keep these items separate, recognizing land as a cost and all of the power generated available for sale, either to the grid or to a power customer.

There is a high degree of uncertainty surrounding land lease costs. It will depend not only on land costs, but also on decisions around feedstock contracting and processing which will influence the amount of land needed. For example, contracting for biomass already chipped to the required size, dried to a contract specified moisture level, and delivered with high frequency would result in the smallest footprint possible. If, however, windrows were necessary for drying relatively wet, uncut green waste delivered infrequently, then a larger acreage would be required.

[15] Notes from May 22, 2008 meeting with Stephen Grealy-The City of San Diego Waste Reduction Disposal Division Program Manager Environmental Services

Other Operating Expenses: The balance of operating expenses are described below.

Environmental: Environmental costs are associated with fees for permits, testing, and auditing required to remain in compliance of applicable environmental regulations.

Other Direct Costs: Other costs constitute mainly administrative expenses such as office and legal expenses

Utilities: Utilities consist of natural gas used during plant start-up, power pulled from the grid, and water.[16]

Consumables: Consumables consist of replacement bed materials, corrosion inhibitors, fuel for feedstock handling equipment, and other minor consumables.[17]

Insurance: Property and liability insurance is estimated at 0.28% of capital costs

Disposal: Disposal captures costs, if any, associated with ash disposal

Details of these expenses are shown in **Appendix E.**

Regulatory Standards/Permits

Satisfying regulatory requirements will play a key role in the realization of a biomass to power project. The specific requirements may vary depending on site options, but air emissions will be the most important factor. In this regard, the proposed project will likely fall under the category of 'stationary source of pollution' under the guidelines of the Clean Air Act, as administered by the federal Environmental Protection Agency (EPA).[17] The EPA sets limits on certain air pollutants, including setting limits on how much can be in the air anywhere in the United States. This helps to ensure basic health and environmental protection from air pollution for all Americans. The Clean Air Act also gives EPA the authority to limit emissions of air pollutants coming from sources like chemical plants, utilities, and steel mills. However, the EPA relies on individual states or tribes to implement the Clean Air Act—states or tribes may have stronger air pollution laws, but they may not have weaker pollution limits than those set by the EPA.

Under the jurisdictions of the Clean Air Act, Title V of the Act issues permits for stationary sources of pollution.[18] Title V operating permits are legally enforceable documents issued to air pollution sources

[16] Note that in sensitivity analyses, utilities and consumables were scaled linearly with capacity up to 5 MW

[17] http://www.epa.gov/air/caa/

[18] http://www.epa.gov/air/caa/title5.html

after the source has begun to operate. Most Title V permits are issued by state, local, and tribal permitting authorities. Most pertinent to the proposed project is the New Source Review (NSR) permitting program, which was established as part of the 1977 Clean Air Act Amendments.[19] Under this program, stationary sources of air pollution are required to obtain an air permit before commencing construction or making certain modifications. The permit specifies what air pollution control devices must be used, what emission limits must be met, and how the facility must be operated.

As a result, state, local, and tribal governments monitor air quality, inspect facilities under their jurisdictions and enforce Clean Air Act and New Source Review regulations. In particular, states have to develop State Implementation Plans (SIPs) that outline how each state will control air pollution under the Clean Air Act. A SIP is a collection of regulations, programs and policies that a state will use to clean up polluted areas. With regards to California, the State is divided into Air Pollution Control Districts (APCD) and Air Quality Management Districts (AQMD), which are also called air districts. These agencies are county or regional governing authorities that have primary responsibility for controlling air pollution from stationary sources. Thus, depending on the site for the proposed project, the requirements vary. A map displaying the Air District Boundaries, with more information on each district, can be accessed at the following website: http://www.arb.ca.gov/capcoa/dismap.htm. The California Air Resources Board (CARB) works closely with the APCD and AQMD to review and approve projects that impact air quality.[20] Anyone proposing to construct, modify, or operate a facility or equipment that may emit pollutants from a stationary source into the atmosphere must first obtain an 'Authority to Construct' from the local air district.[21]

Air districts issue permits and monitor new and modified sources of air pollutants to ensure compliance with national, state, and local emission standards and to ensure that emissions from such sources will not interfere with the attainment and maintenance of ambient air quality standards adopted by the CARB and the EPA. Each air district determines which emission sources and levels have an insignificant impact on air quality and, therefore, are exempt from permit requirements. Examples of activities that may be exempt from the permit requirements include:

- Combustion Equipment Less Than 2 Million Btu / Hr. Fired on Natural Gas / Liquefied Petroleum Gas
- Stationary Piston-Type Internal Combustion Engines with 50 Brake-Horsepower or Less, and
- Incinerators Used in Residential Dwellings for Not More Than Four Families.[22]

Many projects also require a Prevention of Significant Deterioration (PSD) permit from the U.S. Environmental Protection Agency (U.S. EPA). The U.S. EPA requires this permit on a pollutant-by-pollutant basis when two conditions exist:

[19] http://www.epa.gov/NSR/
[20] http://www.arb.ca.gov/ba/fininfo.htm
[21] http://www.arb.ca.gov/permits/airdisac.htm
[22] http://www.arb.ca.gov/nsr/dtvr.htm

- The project's emissions may exceed 100 tons per year for certain industrial activities and 250 tons per year for other industrial activities; and
- The project is in an area where the ambient air quality standard is not being exceeded for the pollutant that the proposed project will emit.[23]

The types of pollutants that do not exceed ambient air quality standards vary from district to district. Developer-applicants should contact U.S. EPA, Region IX, in San Francisco to determine whether their project requires a PSD permit. Because a project may emit several types of pollutants, developer-applicants may need both a PSD permit from U.S. EPA and an 'Authority to Construct' from the local Air District.

Secondarily, anyone operating a facility that emits air pollution must obtain an operating permit from the local air district. The operating permits of major facilities will need to include federal Title V requirements (as mentioned above) in addition to local district requirements. For the purposes of Title V, major facilities are determined based upon the type and amount of emissions and, in some cases, the severity of air pollution problems in the area where the facility is located. Each Air District uses its own application form for the Permit to Operate. In general, the Air District asks the applicant to certify that the developer-applicant completed the construction according to the terms and conditions of the Authority to Construct and that the facility will meet the district's regulations. In addition, the developer-applicant of a facility subject to Title V requirements will need to certify that the facility will comply with any applicable federal requirements. Furthermore, each Air District uses its own 'Permit to Operate' fee schedule. The Air District will generally charge the applicant a permit fee equal to that paid for the 'Authority to Construct', not including the initial filing fee. If the Air District must collect samples to analyze the emission from any source, it will charge the applicant a fee to cover its expenses. The district may require an additional fee for facilities with Title V requirements. Fees range from $100.00 to $10,000.00 in major metropolitan areas.

In summary, the following is a list (by no means exhaustive) of emissions-related regulatory/permitting requirements that the proposed project will need to satisfy depending on the air district under which the site falls in California:

- Clean Air Act Title V Permits
- New Source Review/Federal Core Review
- California Air Resources Board Review
    - ‘Authority to Construct’ Permit
    - ‘Authority to Operate’ Permit
- Prevention of Significant Deterioration (PSD) Permit

[23] http://www.epa.gov/region09/air/permit/psd-issuing.html

Currently, emissions data is not available for the proposed plant, but such emissions are expected to be low.

Production Credits/Incentives

The federal government has long standing incentives supporting renewable energy, starting initially with the passage of the Public Utility Regulatory Policies Act (PURPA) in 1978. PURPA provided a series of incentives to "qualifying facilities" which includes cogeneration facilities and small power production facilities that use biomass, waste, or renewable resources (including wind, solar, and water).[24] Note that the proposed biomass to power project on the Miramar landfill would likely be able to obtain qualifying facility designation. At the time of its passage, one of PURPA's important provisions required utilities selling retail power to purchase from the small, independent qualifying facilities at the utility's avoided cost rate to procure or produce the power from other sources. This provision, however, has become less important as open electricity markets have developed significantly since the original passage of PURPA along with the adoption of Renewable Portfolio Standard (RPS) by various regulatory authorities (principally at the state level). The impact of RPS is discussed in more detail below. Still applicable today, another key provision of PURPA exempted qualifying facilities from various federal and state statues that regulated utilities, in effect making it easier to develop and operate small, independent power plants. Finally, PURPA provides certain tax incentives, significantly the ability to accelerate depreciation. PURPA was subsequently amended under the Energy Policy Acts of 1992 and 2005, the latter of which created production tax credits for renewable power. These production tax credits apply to the following general categories of "qualified energy resources": wind, closed-loop biomass, open-loop biomass, geothermal energy, solar energy, small irrigation power, municipal solid waste, and qualified hydropower production.[25] The amount and time period of the production tax credits varies based upon the source of the renewable energy. The project under consideration for the Miramar landfill, an open-loop biomass facility using cellulosic waste, qualifies for production tax credits of $0.01/KWh for a period of 5 years from the date the facility is placed in service.[26]

In addition to incentives at the federal level, there are production credits and incentives in California that exist in order to widen the landscape for investment and development opportunities in the alternative energy sectors. In specific regard to renewable power, the California Energy Commission (CEC) administers programs to promote both existing and emerging renewable resource technologies. Authorization for these activities was renewed in Senate Bill (SB) 1038, which became law in 2002. However, the programs the CEC has adopted to promote renewable power continue to predominantly favor solar and wind. (Please refer to Appendix F for a more detailed explanation of the existing programs and why the proposed project does not meet their requirements.) Of the programs created under SB 1038, only the New Renewable Facility Program indirectly benefits the proposed project at Miramar. This program provides funds to retail utilities to supplement their cost to procure renewable

[24] S. Spiewak, Larry Weiss, *Cogeneration & Small Power Production Manual*, 1999, p. 23
[25] Title 26. Internal Revenue Service Code, Section 45
[26] IRS form 8835, Renewable Electricity, Refined Coal, and Indian Coal Production Credit

energy at above-market costs. In this sense, this program provides funding for the implementation of the Renewable Portfolio Standard by California's retail utilities.

As for the potential to bundle the cleaner energy that could be produced from the proposed gasification technology for Renewable Energy Credits (REC), there is much volatility and uncertainty surrounding the REC market at present. RECs are tradable environmental commodities that represent proof that 1 megawatt-hour (MWh) of electricity was generated from an eligible renewable energy resource. These certificates can be sold and traded and the owner of the REC can claim to have purchased renewable energy. While traditional carbon emissions trading programs promote low-carbon technologies by increasing the cost of emitting carbon, RECs can incentivize carbon-neutral renewable energy by providing a production subsidy to electricity generated from renewable sources.[27]

For states that have a REC program, a green energy provider (such as a wind farm) is credited with one REC for every 1,000 kWh or 1 MWh of electricity it produces. A certifying agency gives each REC a unique identification number to make sure it doesn't get double-counted. The green energy is then fed into the electrical grid (by mandate), and the accompanying REC can then be sold on the open market.
According to the Green Power Network, prices of RECs can fluctuate greatly (2006: from $5 to $90 per MWh, with a median of about $20).[28] Prices depend on many factors, such as the location of the facility producing the RECs, whether there is a tight supply/demand situation, whether the REC is used for RPS compliance, even the type of power created. At present, the value of RECs in California is minimal, given the voluntary status of the market.[29] These are spec revenues and should be considered best case. Things could change in the next 6-12 months however, as the political climate shifts with a new federal administration.

A second potential source of credits is greenhouse gas-specific. Carbon credits are a key component of national and international emissions trading schemes that have been implemented to mitigate global warming. They provide a way to reduce greenhouse effect emissions on an industrial scale by capping total annual emissions and letting the market assign a monetary value to any shortfall through trading. Credits can be exchanged between businesses or bought and sold in international markets at the prevailing market price. Credits can be used to finance carbon reduction schemes between trading partners and around the world.[30]

There are also many companies that sell carbon credits to commercial and individual customers who are interested in lowering their carbon footprint on a voluntary basis. These carbon offsetters purchase the credits from an investment fund or a carbon development company that has aggregated the credits from individual projects. The quality of the credits is based in part on the validation process and

[27] http://www.nativeenergy.com/pages/faq_s/15.php
[28] http://www.eere.energy.gov/greenpower/markets/certificates.shtml?page=1
[29] Conversation with industry expert, Jay Brandeis at Teotl Energy Consulting: jay@teotlenergy.com
[30] http://en.wikipedia.org/wiki/Carbon_credit

sophistication of the fund or development company that acted as the sponsor to the carbon project. This is reflected in their price; voluntary units typically have less value than the units sold through the rigorously-validated Clean Development Mechanism.

It is also important for any carbon credit (offset) to prove a concept called additionality. Additionality is a term used by Kyoto's Clean Development Mechanism to describe the fact that a carbon dioxide reduction project would not have occurred had it not been for concern for the mitigation of climate change. More succinctly, a project that has proven additionality is a beyond-business-as-usual project. Under this requirement, it is unlikely that the project under consideration would be able to generate carbon credits. The biomass-to-power project depends on converting feedstock that would otherwise be destined for the landfill and/or other conversion methods (landfill gas-to-methane production, etc.) and would fall under the business-as-usual category.[31]

Due to the complicated and chaotic nature of the credits/incentives market, it would be prudent to focus on revenue structures that are less risky.

Feed in Tariff

A Feed in Tariff is an incentive structure to encourage the adoption of renewable energy through government legislation.[32] In order to meet the California Renewable Portfolio Standard (RPS) created under SB 1078 and accelerated under SB 107, Investor Owned Utilities (IOU) are required to purchase or generate 20% of their electricity from renewable sources by 2010. Of this amount, Governor Schwarzengger has mandated that 20% come from biomass to electricity projects.[33] In order to do so, utilities have established Feed in Tariffs and standard contracts to help expedite the deployment of renewable projects. Southern California Edison (SCE) has one such program for biomass projects ranging in size from less than 1 MW up to 20 MW.[34] Standard contracts incorporate Time of Day (TOD) pricing along with the assignment of all green attributes, such as RECs and carbon credits, to SCE. For example plants that chose a 20 year contract with an on-line year of 2010 the standard contract rate is $98.40 per MWh. Southern California Edison provides an Excel Spreadsheet that will calculate revenue based upon contract pricing and expected production rate. Due to the current market uncertainty for Renewable Energy Credits and Carbon Credits, contracting for a Feed in Tariff represents the lowest risk revenue source for the proposed Miramar biomass to power facility.

[31] http://www.climatetrust.org/solicitations_2005_Additionality.php
[32] http://en.wikipedia.org/wiki/Feed-in_Tariff
[33] http://gov.ca.gov/executive-order/183/
[34] http://www.sce.com/EnergyProcurement/bsc.htm

Considered Scenarios and Corresponding Financials

Three potential location scenarios were analyzed for economic feasibility. This analysis was conducted with an economic, Excel™-based model which the team developed by expanding upon a simple model available on The California Biomass Collaborative website.[35] Appendix G describes this model in further detail. Certain assumptions were made which apply to all three scenarios. Some of these assumptions were subsequently tested in sensitivity analyses.

Significant Inputs: With respect to revenue potential, power sales were assumed at the feed-in rate set for small biomass facilities, or in the case of MCAS Miramar, at the incremental cost of power for the retail customer. As previously discussed, capturing revenue associated with environmental attributes from items such as RECs or carbon credits represent some degree of risk. Therefore, such revenue was not considered in any of the cases. It is contractually relinquished in the cases where a feed-in tariff is assumed. Lastly with regard to revenue, waste heat sales are assumed to be zero for all three cases, although it is feasible a customer of waste heat could be located at a future site.

Financial assumptions included using a cost of equity of 20%, a cost of debt of 5%, and 50% leverage[36], except in the 3rd "generic" case where leverage was increased to 65%. Sensitivities were subsequently conducted on both the cost of debt and the leverage. Of considerable economic value, biomass facilities that receive "qualifying facility" status under the Public Utility Regulatory Policy Act (PURPA) may use 5-year accelerated (MACRS) depreciation. This incentive was included in all scenarios considered. A simple construction period model of 9 months was used in all cases wherein all capital investment was assumed to occur at time 0 with revenues and most expenses initiating 9 months later. Certain fixed costs such as land lease, insurance, and utilities as well as 49% of the labor cost (including plant management, lead operator/maintenance, and administrative assistance) commenced at the time of capital investment.

The balance of the operating costs, significantly feedstock costs and the remaining labor costs, begin upon start-up of the facility after the 9 month construction phase. It is likely that this construction period assumption is conservative depending on how such a project is actually financed and conducted. Other financial assumptions include a 20 year project life without any additional capital investment. Consequently, no value associated with cash flows continuing in perpetuity was included. An inflation rate of 2.1% was applied to operating expenses, including feedstock. This same inflation rate was applied to escalate the production tax credit since current law allows for such inflation escalation. While not used in the three scenarios analyzed, heat sales also escalated at this inflation rate in the sensitivity analyses employed to analyze the scenarios.

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[35] http://biomass.ucdavis.edu/index.html

[36] Guidance on these financial assumptions per EnXco

Another input included assuming an on-stream (uptime) rate of 93% (with a sensitivity analysis conducted on lower on-stream rates). Finally, note that the three scenarios analyzed were for a 3 MW plant, although capital and certain operating costs were scaled to 5MW in a plant sizing sensitivity analysis.

In addition to the inputs discussed above, certain inputs were modeled as probabilistic variables feeding Monte Carlo simulations for the first two scenarios analyzed. The inputs which were modeled as varying over a normal distribution included:

Table 4: Probabilistic economic variables

Input	Mean	99%-tile	Distribution
Gasifier Capital Cost	$6,000,000	$7,395,800	Normal
Feedstock Higher Heating Value (HHV)	7,000 BTU/dry lb	8,630 BTU/dry lb	Normal
Cost of Natural Gas for Facility Starts	$11.00/MMBTU	$12.80/MMBTU	Normal

Scenario 1: Miramar Landfill

In keeping with the term sheet directing this study, the initial business plan considered was locating the facility on the Miramar landfill in San Diego, California. Among other reasons, Miramar was chosen for this feasibility study since diversion of green waste to the gasifier could extend the life of the landfill. Initially, the landfill was believed to be scheduled to close in December 2011.[37] Extending the life of the landfill has economic value to the city since, upon closure of the landfill, waste will need to be diverted to other landfills adding to transportation costs.

One of the challenges to the feasibility of the proposed project is that the City of San Diego has alternatives available to it to extend the life of the landfill. One alternative that has been successfully pursued is to increase the capacity of the landfill. In March 2008, the City of San Diego received approval from the California Integrated Waste Management Board for several changes to the Miramar landfill Solid Waste Facility and Site Development Permits. Amongst other changes, this allowed for a 20 foot increase in the maximum height of the landfill to a maximum elevation to 485 feet above mean sea level, resulting in an increase of 12,550,000 cubic yards from the current permitted capacity. This pushed back the estimated closure year to 2017.[38] Additionally, the landfill operating life can be further extended through increased diversion.

[37] California Integrated Waste Board Management, *Active Landfills Profile for West Miramar Sanitary Landfill*, http://www.ciwmb.ca.gov/Profiles/Facility/Landfill/LFProfile3.asp?COID=37&FACID=37-AA-0020

[38] State of California Office of Planning and Research, *Notice of Determination – Miramar Landfill Height Increase*, March 25, 2008

The consequences of having alternatives to extend the landfill life are that the city is not inclined to share any benefits associated with a longer life of the landfill. Closure of the landfill is not imminent and multiple opportunities exist for the city not only to extend the life of the landfill, but also increase revenues associated with the green waste it handles. One potential forecast of the future is that the city will gradually lower the price of green waste and loosen contract terms as the costs of transporting green wastes to more distant landfills becomes more imminent. Such a strategy will allow the city to actively balance revenues from green waste against these future costs in order to maximize revenue.

There are additional disincentives beyond the inability to capture economic rents associated with extending the life of the landfill and the anticipated high price of feedstock. As described above, the landfill continues to pursue a strategy of seeking higher height allowances enabling a greater capacity. Due to height restrictions imposed by the Miramar Marine Core Airs Station (MCAS) this strategy competes directly with the project concept of locating a 40 foot tall gasifier on the landfill. In short, the landfill's permits make siting such as gasifier on the landfill extremely difficult since additional height allowances have been and will be used to increase the landfill capacity.

Another disincentive for siting the gasifier on the Miramar landfill is the lack of a clear source of waste heat revenue. Thermophilic composting may be of value when the Miramar landfill does close allowing for a reduction in weight of material moving through Miramar as a transfer station. Initial discussions with landfill personnel, however, showed little prospect that such value could be captured by the project until such time that the landfill does close, if ever. As previously noted, the date of landfill closure continues to be pushed further into the future. Furthermore, unused waste heat is already available from the Minnesota Methane landfill gas facilities.

In conclusion, there are non-economic factors weighing unfavorably on the proposed project being sited at the Miramar landfill including very short term contracts on feedstock and height restrictions. Additionally, there are several economic factors making the project appear less viable including high feedstock costs and the lack of a waste heat revenue stream. Nevertheless, given these challenging economic inputs, a financial model was constructed using appropriate inputs for the Miramar landfill site.

Miramar Landfill Case - Major Assumptions and Inputs:

1. Feedstock cost is assumed to be $15/short ton
2. Land lease cost is assumed to be $100,000 per year
3. Electricity sales at Southern California Edison feed-in rate, foregoing revenue associated with REC's and other environmental offsets.
4. No opportunity for waste heat revenue

Miramar Landfill Case – Results and Discussion:

The levelized annual cost (LAC) results from the Monte Carlo simulation for the Miramar landfill scenario are shown in the cumulative probability figure below.

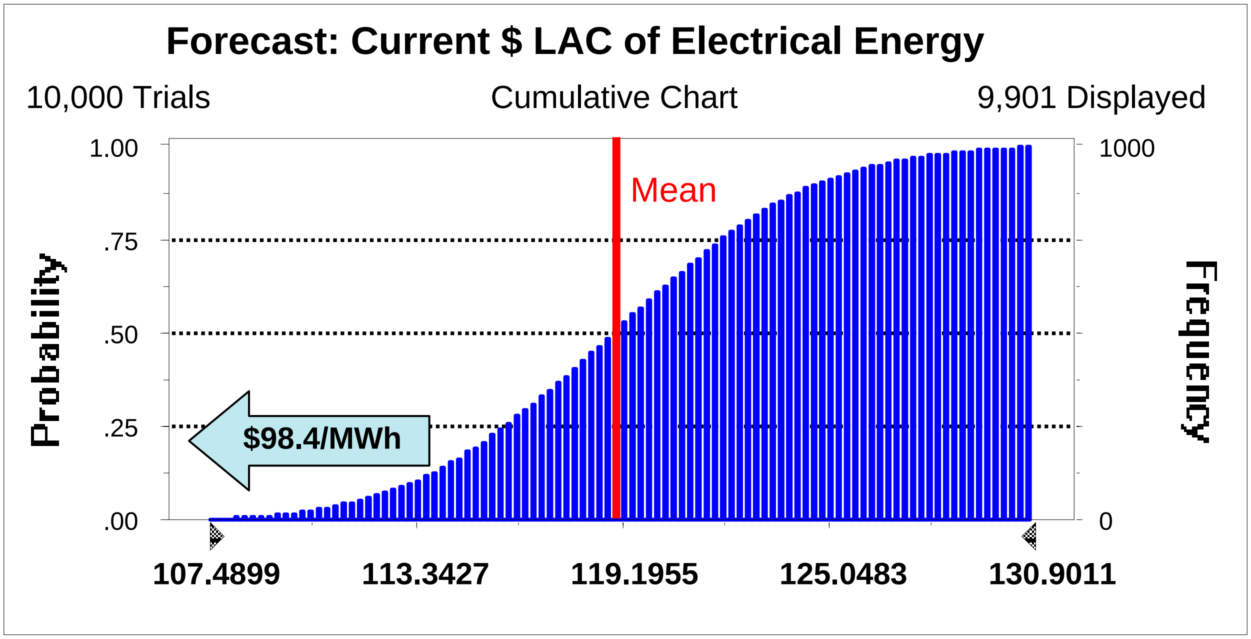


Figure 3: Cumulative probability of levelized annual cost for Miramar Landfill Case

Figure 3, with the mean LAC at $119.2/MWh, predicts that there is essentially no chance that the LAC of the power produced at the site will be less than $107.4/MWh. This is an unfeasible cost structure in the case that the power sales are to occur at the feed-in rate of $98.4/MWh. An alternative evaluation, coming to the same conclusion regarding the infeasibility of the project, is that at a power sales price of $98.4/MWh, the net present value (NPV) for the project, under the inputs outlined above, is -$2.7 million. Putting aside the inability to site on the Miramar landfill, economically a project would have a 50% chance of meeting desired returns on capital if sales could be made to a retail customer willing to pay greater than $119.2/MWh plus any wheeling charges associated with transmitting and selling power to this retail customer.

Scenario 2: MCAS Miramar

In addition to the base case of siting the gasifier on the Miramar landfill, a related case was explored. In this case, a gasifier to power project was located on the MCAS Miramar with feedstock supplied from the Miramar landfill. This option was initially explored to overcome the height restriction in place at the landfill as well as the potential for a waste heat customer. To date, MCAS Miramar command personnel contacted have indicated they have no need for waste heat. To be conservative, this case was modeled without waste heat although the project team believes this issue might be worthy of continued investigation. An additional opportunity with siting the project on the air station is for higher contract terms on the power generated since this power now replaces other potentially higher cost sources of power, such as purchasing power off the grid. While enhancing the economics versus a project directly on the landfill, the feedstock costs were modeled to be equal to the landfill green waste price plus additional transportation costs to move the feedstock to the MCAS. While the potential exists to bypass Miramar landfill green waste, perhaps contracting directly with green waste collectors, doing so would require additional land area on the air station for feedstock preparation (chipping and drying), land that may not available. Finally, the power rate modeled represents the air station's incremental cost of power. Therefore, the project would likely be able to retain any green attributes for which the project might qualify. This represents a possible additional source of revenue, albeit uncertain, which was not included in our analyses.

MCAS Miramar Case - Major Assumptions and Inputs:

1. Feedstock cost is assumed to be $20/short ton (Miramar input costs + transportation costs)
2. Land lease costs is assumed to be $50,000 per year
3. Electricity sold at $0.10 per kW-hr ($100/MWh), the MCAS next best alternative for incremental power.
4. No opportunity for waste heat revenue

MCAS Miramar Case – Results and Discussion:

The levelized annual cost (LAC) results from the Monte Carlo simulation for the MCAS Miramar scenario are shown in the figure below.

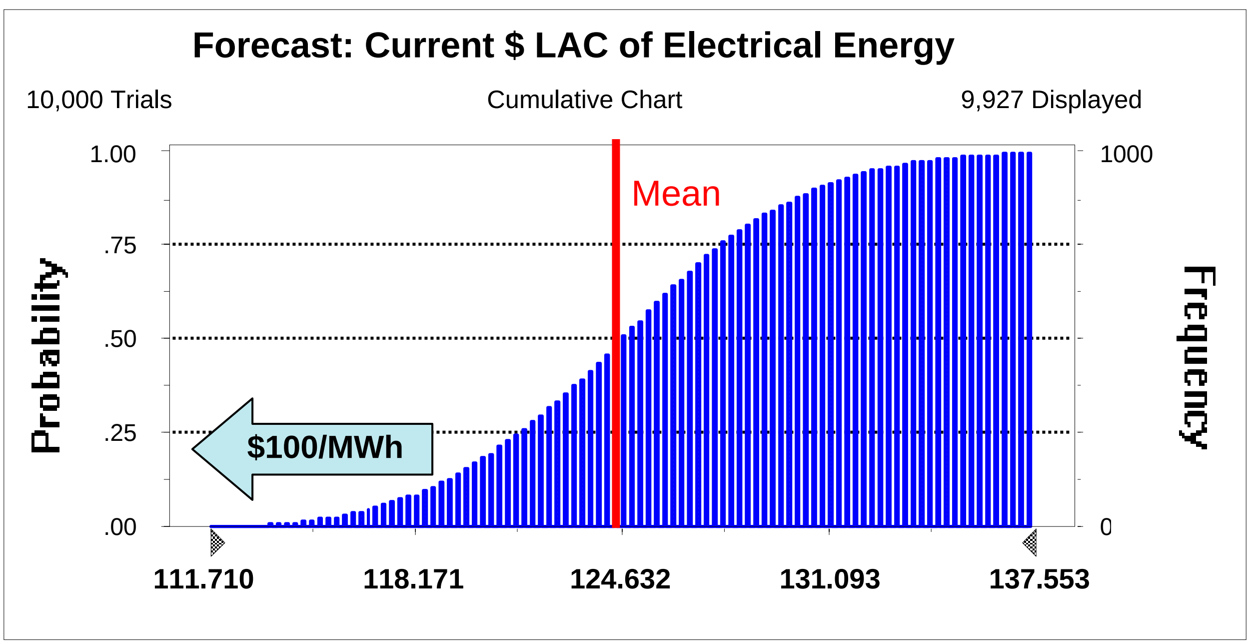


Figure 4: Cumulative probability of levelized annual cost for MCAS Miramar Case

Figure 4, with a mean LAC of $124.6/MWh, predicts that there is essentially no chance that the LAC of the power produced at the site will be less than $111.7/MWh. This is an unfeasible cost structure in the case that the power sales are to occur at the MCAS incremental cost of $100.0/MWh. An alternative evaluation, coming to the same conclusion regarding the infeasibility of the project, is that with a power sales price of $100.0/MWh, the net present value (NPV) for the project, under the inputs outlined above, is -$2.8 million. In comparison to the first case, the slightly higher power price is more than offset by the increase in feedstock costs, resulting in an even higher LAC.

Scenario 3: General Case - Other Location

Further extending the considered business cases, a more general option was modeled. In this case, feed-in tariff rates available in California from utilities such as Southern California Edison were again used for the calculation of power revenue. Differing from the other scenarios, this case assumed much more favorable prices and terms in contracting for feedstock. Whether achieved through contracting with multiple green waste generators, such as landscaping companies, or through a single large generator, it was assumed that a reliable supply of feedstock could be achieved at prices much lower than being offered by the Miramar landfill.

Other Location - Major Assumptions and Inputs:

1. Feedstock cost is assumed to be $2/short ton
2. Land lease costs is assumed to be $30,000 per year
3. Electricity sales at Southern California Edison feed-in rate, foregoing revenue associated with REC's and other environmental offsets.
4. No waste heat revenue
5. Leverage increased to 65%

Other Location– Results and Discussion:

By increasing the leverage in this "generic" case to 65%, yielding a weighted average cost of capital (WACC) of 9%, a positive NPV project was generated for this hypothetical case selling at the feed-in tariff rate of $98.4/MWh.

Figure 5 illustrates the components of the NPV of the project. Of significance, the tax incentives in the form of production tax credits and accelerated depreciation are needed to create an NPV positive project. Note that an NPV positive project could also be developed at the baseline 50% leverage with either a larger plant or some waste heat sales. The sensitivity of project returns to these and other areas are explored in the next section.

Components of NPV	
Initial Investment	($8,725,000)
EBITDA	$8,776,424
Taxes on EBITDA	($3,540,059)
Production Tax Credit	$910,005
Depreciation Tax Shield	$2,619,301
Working Capital Additions	$0
NPV	$40,671

Figure 5: Components of NPV for General case

Sensitivity Analysis

The sensitivity of the "generic" project's NPV, with $2/ton feedstock and 50% leverage, was tested against several input parameters.

A 3MW facility generates approximately 4,900KW of heat. This heat can be utilized when the plantis outfitted with heat recovery equipment. This equipment is estimated to cost $150/KW of electrical capacity, so recovering heat on a 3MW facility requires an additional investment of $150 x 3000 KW = $450,000. Figure 6 below shows the NPV of the project at various power prices and waste heat prices. As shown in the figure, the additional revenue potential more than pays for the additional capital costs with the opportunity to significantly enhance the project returns. At baseline assumptions, a minimum waste heat price of $1.5/MMBtu would yield a feasible project. Note that the current cost of natural gas is over $12.00/MMBtu. At the feed-in rate of $98.4/MWh, the project NPV would be approximately $2 million if the captured waste heat was sold at $4.50/million BTU. Higher prices for waste heat would lead to even greater returns.

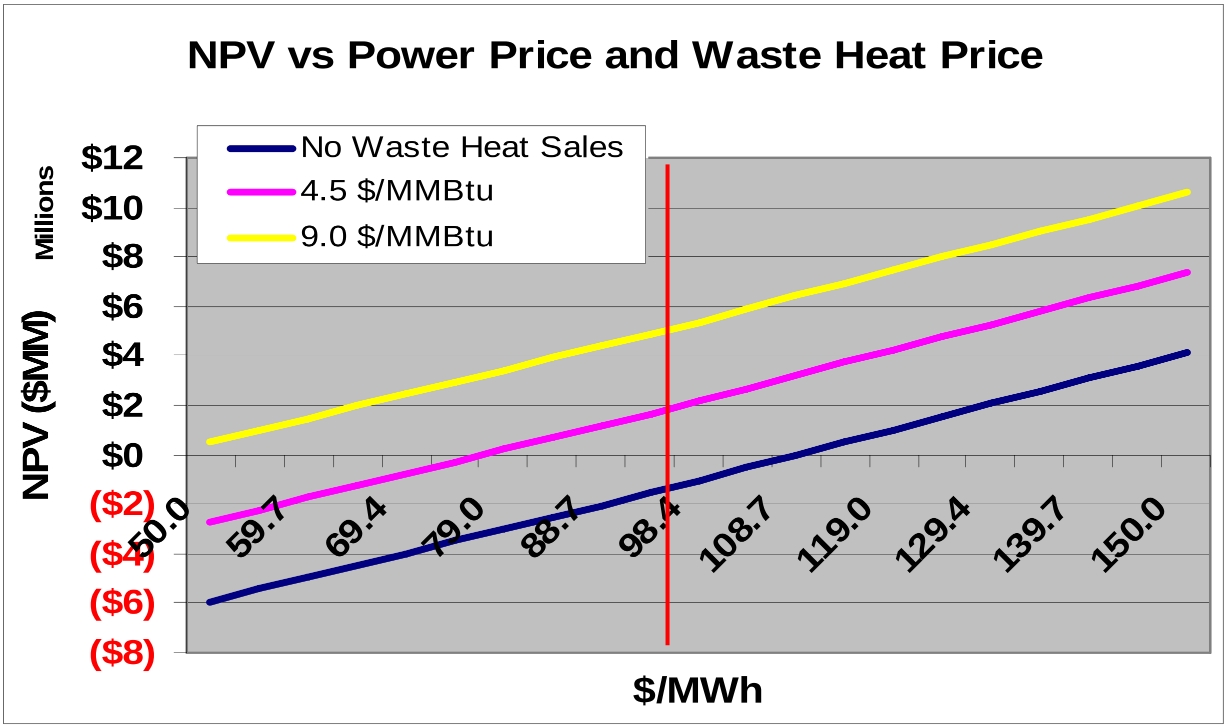


Figure 6: Sensivitity of project returns to power prices and waste heat prices

In summary, the ability to sell waste heat at $4.5/MMBtu is worth essentially $0.03/KWh, demonstrating the waste heat revenue potential as being one of the more sensitive parameters impacting the project returns. Note that waste heat revenues were assumed to escalate with inflation. If a site can be found that combines availability of feedstock with a host heat customer, the project could provide attractive returns.

Additionally, the project returns were quite sensitive to plant sizing. In order to model the impact of returns on plant size, the capital investment and some of the operating expenses were scaled up from the 3MW facility. The gasifier capital cost was scaled by the square root of the ratio of the capacity; a 5MW gasifier was estimated to cost $6 million x (5MW/3MW)^0.5 = $7.746 million. The engine/generator sets were scaled linearly (at $750/KW). A larger plant, which was assumed to have the same efficiencies as a 3MW facility, will require more feedstock in direct proportion to the power output of the plant. Some operating costs were scaled linearly including maintenance, consumables and utilities. Significantly, the largest operating cost, labor, was left the same for a 5MW plant under that assumption that the same manpower required for a 3MW facility could operate the larger plant. Figure 7 below graphs the NPV for a 5MW plant at different power prices versus the 3MW plant. Note that approximately $2 million of NPV is generated by a 5MW facility at the feed-in tariff price of $98.4/MWh. It was found that at breakeven ($0 NPV), moving from 3MW to 5MW is worth approximately $0.025/KWh.

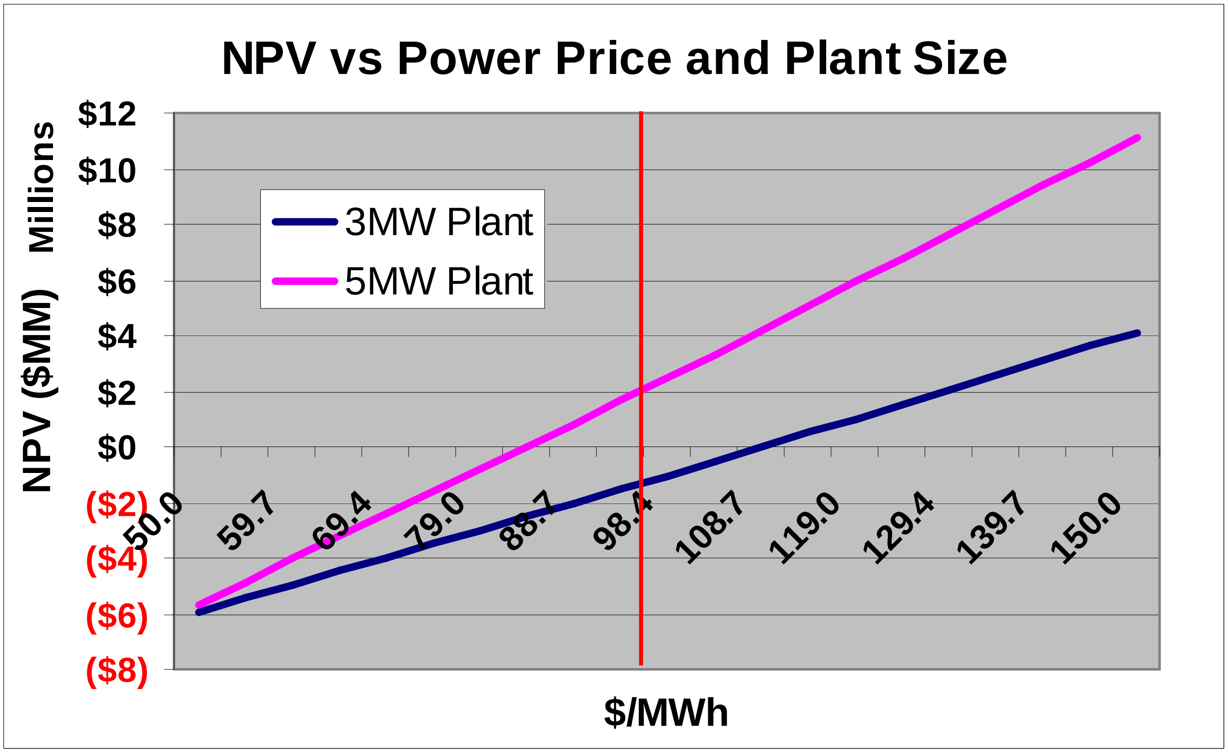


Figure 7: Sensitivity of project returns to power prices and plant size

A couple of sensitivity analyses were conducted on operating parameters. Presented below are project NPV at differing power sales rates and feedstock costs. As one would expect, at a given power sales price, project returns degrade with increasing feedstock costs. Note that negative feedstock cost, in the form of tipping fees to accept green waste, is not beyond possibility and would improve project returns.

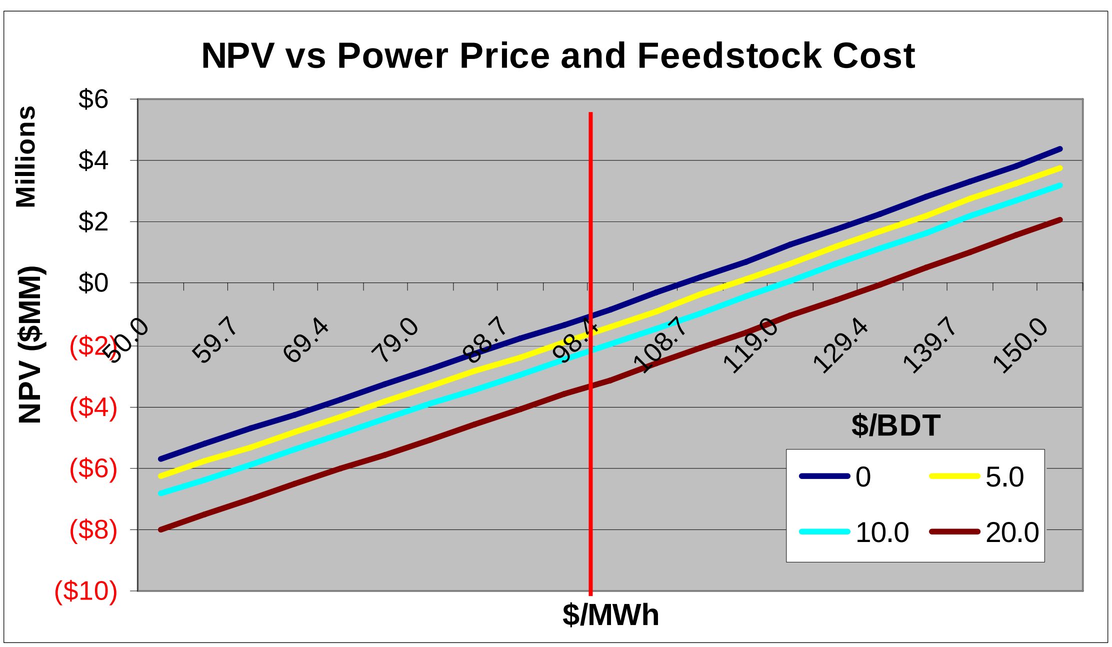


Figure 8: Sensitivity of project returns to power prices and feedstock costs

Figure 9 below shows the impact of decreasing onstream rates below the aggressive baseline of 93%. This illustrates that significant operational risk exist. Note that this analysis assumes downtime at an average power sale price as shown on the x-axis. The contractual feed-in tariff, however, varies significantly by time of day and season, with prices during peak summer hours over 3 times the average price while offpeak sales are lower than 0.7 times the average. Therefore, the time of day and season when downtime occurs will also impact project returns.

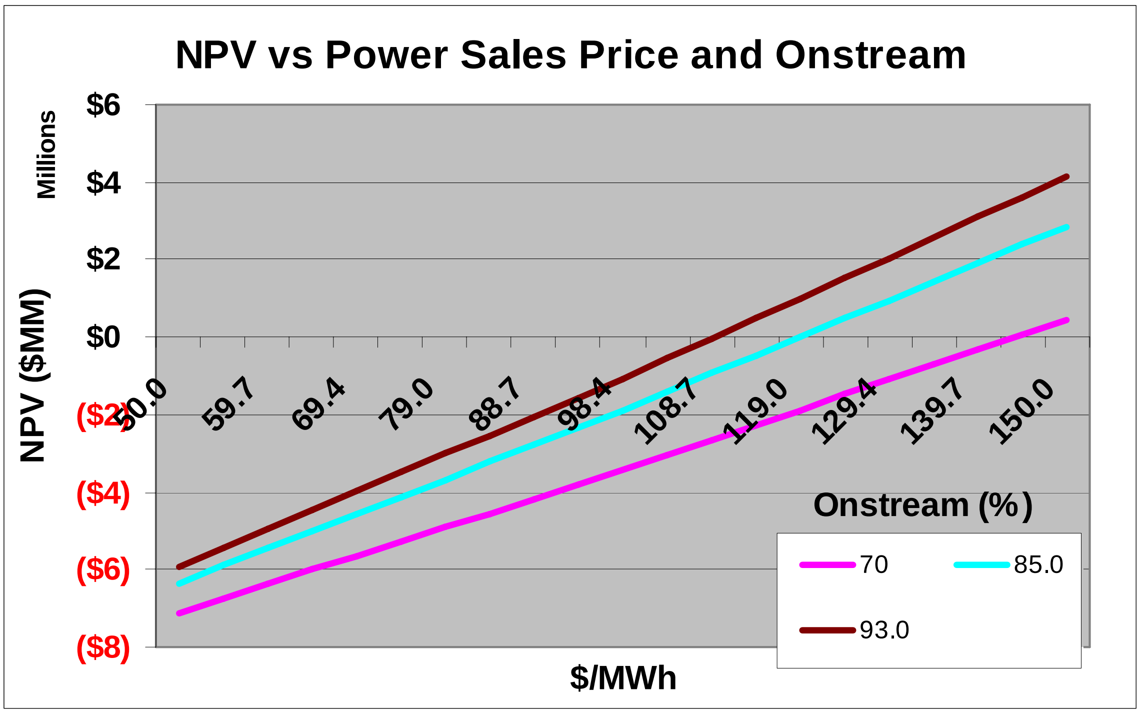


Figure 9: Sensitivity of project returns to power prices and onstream rates

Lastly, a financing sensitivity was performed exploring the impact of leverage and debt cost. Figure 10 below demonstrates increasing NPV with increasing leverage as a result of the lower cost and tax advantages of debt financing. It is not atypical for power projects of this type to utilize a high degree of leverage, well above the baseline case of 50% modeled. As the figure indicates, the project returns are relatively more sensitive to leverage than to debt cost.

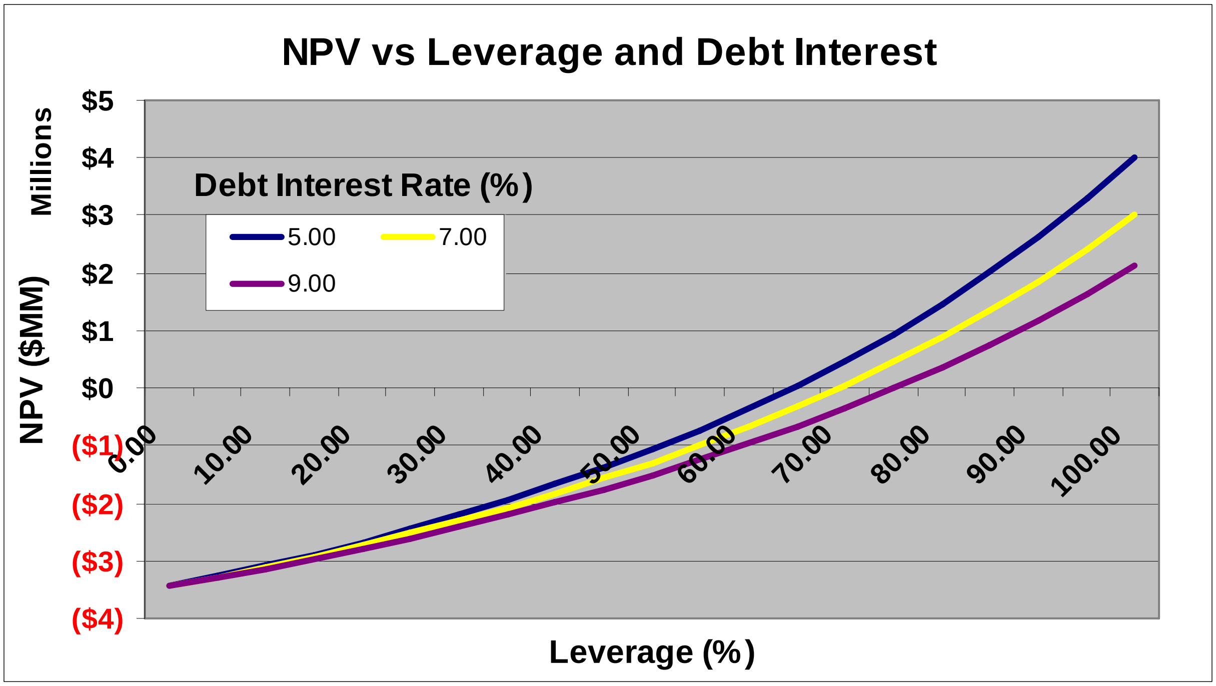


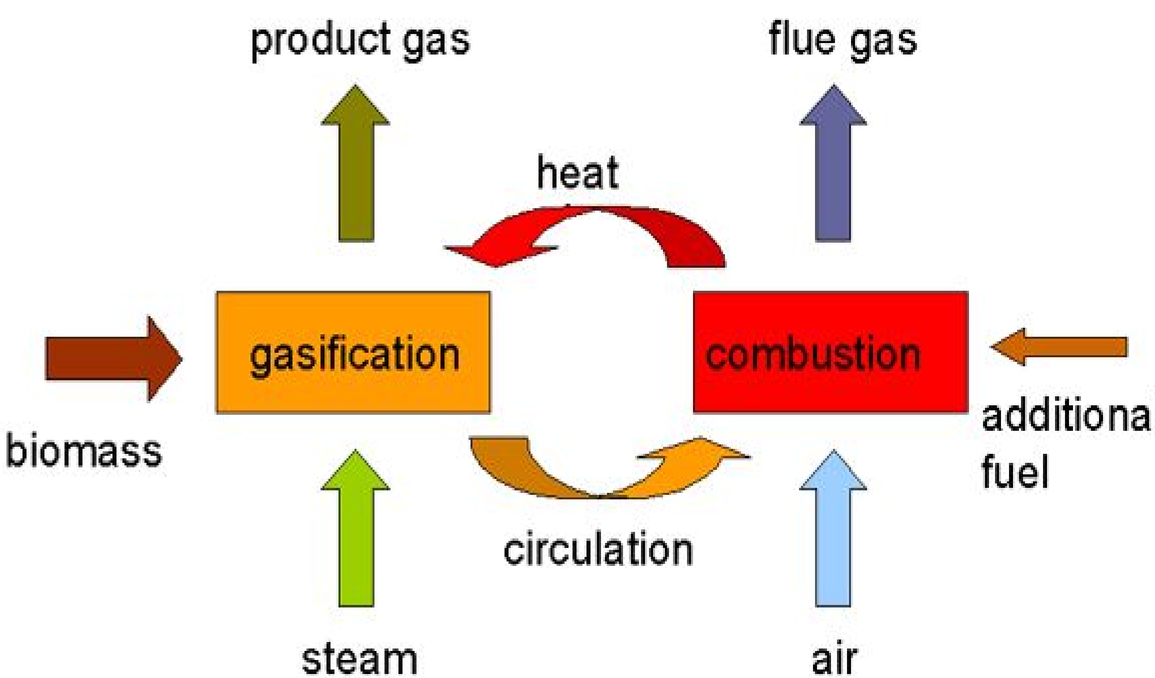
Figure 10: Sensitivity of project returns to financial leverage and debt interest rates

Conclusions and Recommendations

Based on height restrictions and other factors, it appears unlikely that a biomass gasification power plant could be located on the Miramar landfill. Furthermore, establishing long-term, cost effective feedstock supply from the landfill appears difficult, at best. Lastly, there are no evident opportunities for waste heat revenue for a plant located on the landfill. For these reasons, locating a biomass power plant on the Miramar landfill is not deemed feasible at this time. Even when putting aside some of these factors, without the prospect of waste heat revenue, the project would need power revenue at over $119/MWh, well over feed-in tariffs and the incremental cost of power for most industrial or institutional users. There is, however, the possibility that some customer would want to pay premium pricing for the renewable power produced by the plant.

To overcome some of the obstacles mentioned above, siting a plant on another major landfill, such as the relatively new Sycamore landfill in San Diego county, could be explored. Cheaper and more reliable supply of feedstock that an alternate landfill could provide would certainly enhance the project's prospects. The project returns, however, are much more sensitive to being able to generate waste heat revenue. As such, locating a waste heat customer in close proximity to the proposed biomass plant would be one of the more effective steps that could be taken to meet desired returns for the project. The project returns were also quite sensitive to plant size. If the emissions performance of the gasification technology allowed the plant to scale to 5MW, as modeled, the plant would be much more economically viable.

Appendix A


product gas
flue gas
heat
gasification
combustion
biomass
additional
fuel
circulation
steam
air

Appendix B

LABOR	
Position	**Annual Cost 2008**
Plant Mgr.	$80,000
Plant Operator	$45,000
Plant Operator	$45,000
Plant Operator	$45,000
Fuel Operator	$40,000
Fuel Operator	$40,000
Field Labor Subtotal	$295,000
Benefits Factor	20%
Burden Rate Factor	20%
Field Labor Total	$413,000
Admin	$40,000
Benefits Factor	20%
Burden Rate Factor	15%
Admin Labor Total	$54,000
Total	$ 467,000

Appendix C

MAINTENANCE	
Type	**Annual Cost 2008**
enXco factor for parts ($/MW)	$7
Parasitic load %	2%
Capacity %	93%
Total	$ 167,661

Appendix D

EQUIPMENT LEASE	
Type	**Annual Cost 2008**
Small-wheeled Loader	$30,000
Tracked Dozer	$50,000
Grapple	$45,000
Total	$ 125,000

Appendix E

ENVIRONMENTAL	
Type	**Annual Cost 2008**
Emissions Testing	$30,000
Environmental Audit	$10,000
Fees, Permits	$10,000
Safety Equipment	$1,000
Safety Training	$1,000
Environmental Consultants	$10,000
Water Testing	$0
Ash Testing	$1,000
Total	$ 63,000

OTHER DIRECT COSTS	
Type	**Annual Cost 2008**
Building/Grounds Maint.	$10,000
Office Expenses	$10,000
Freight and Postage	$5,000
Audits	$15,000
Legal	$15,000
Total	$ 55,000

UTILITIES	
Type	**Annual Cost 2008**
Natural Gas Cost / MMBTU	$11
Hours / Start	4
MMBTU / Hour	90
System Restarts / Year	6
Natural Gas	$23,760
Electricity / Power	$5,000
Interconnect Fee	$25,000
Water	$16,000
Total	$ 69,760

CONSUMABLES	
Type	**Annual Cost 2008**
Replacement Bed Material / MW	$10,000
Corrosion Inhibitors / MW	$500
Other / MW	$500
Replacement Bed Material	$30,000
Corrosion Inhibitors	$1,500
Other	$1,500
Fuel for Mobile Eqmt.	$5,000
Total	$ 38,000

INSURANCE	
Type	**Annual Cost 2008**
enXco insurance multiplication factor Package, Liability, Property, Earthquake	0.28%
Total facility cost	$8,725,000
Workers' Comp in Burden Rate, See Labor tab.	n/a
Total	$ 24,430

DISPOSAL	
Type	**Annual Cost 2008**
Tipping Fee / Ton	$10
Tons of Char / Year	1681
Total	$ 16,812

Appendix F California Energy Commission Incentive Programs[39]

Overall Renewable Energy Program: Renewables Portfolio Standard Eligibility

The California Energy Commission (Commission) has developed *Guidelines* to implement and administer its Renewable Energy Program under Senate Bill 10381 and Senate Bill 1250.2 These laws, along with the Reliable Electric Service Investments Act, 3 extend the collection of a non-bypassable system benefit charge initiated in 1998 under Assembly Bill 18904 and authorize the expenditure of funds collected to support existing, new, and emerging renewable resources. The goal of these laws is to establish a competitive, self-sustaining renewable energy supply for California while increasing the near-term quantity of renewable energy generated within the state.

Definition of eligible biomass:

Biomass — any organic material not derived from fossil fuels, including agricultural crops, agricultural wastes and residues, waste pallets, crates, dunnage, manufacturing, construction wood wastes, landscape and right-of-way tree trimmings, mill residues that result from milling lumber, rangeland maintenance residues, biosolids, sludge derived from organic matter, and wood and wood waste from timbering operations.

Agricultural wastes and residues include, but are not limited to, animal wastes, remains and tallow; food wastes; recycled cooking oils; and pure vegetable oils.

Landscape or right-of-way tree trimmings include all solid waste materials that result from tree or vegetation trimming or removal to establish or maintain a right-of-way on public or private land for the following purposes:

1. For the provision of public utilities, including, but not limited to, natural gas, water, electricity, and telecommunications.
2. For fuel hazard reduction resulting in fire protection and prevention.
3. For the public's recreational use.

Existing Renewable Facilities Program

There is $72,180,000 available.The purpose of the ERFP is to improve the competitiveness of existing in-state renewable generating facilities so these facilities may become self-sustaining without further public funding, and to secure for California the environmental, economic, and reliability benefits these facilities provide by continuing to operate.

The ERFP provides funding in the form of production incentives to eligible renewable energy facilities for each kilowatt-hour of eligible electricity generated. To qualify for funding, applicants must ensure that the renewable facility and electricity generated meet a number of requirements. The facility must use an

[39] The Complete Guidebook to the CEC's Renewable Standard Portfolio Program can be found online at: http://www.energy.ca.gov/renewables/documents/index.html

eligible renewable energy resource to generate electricity, and be located either within the state or near the state's border with its first point of interconnection to the transmission systems within the state. Eligible renewable energy resources include biomass, solar thermal electric, and wind. In addition, the facility must not be owned by an electrical corporation or local publicly owned electric utility and must be certified by the Energy Commission as eligible for California's Renewables Portfolio Standard (RPS). Lastly, the electricity generated must not be sold under a fixed price contract with an energy price above the applicable target price. 5 on a monthly average basis, be used on-site, or sold in a manner avoiding competitive transition charge payments.

Facilities must satisfy the following requirements to participate in the ERFP.

1. Facilities must use eligible solid-fuel biomass, solar thermal electric, or wind energy to generate electricity. Eligible solid-fuel biomass is limited to the following:
   a. Agricultural crops and agricultural wastes and residues.
   b. Solid waste materials such as waste pallets, crates, dunnage, manufacturing, and construction wood wastes, landscape or right-of-way tree trimmings, mill residues that are directly the result of the milling of lumber, and rangeland maintenance residues.
2. Wood and wood wastes that meet all of the following requirements:
   a. Have been harvested under an approved timber harvest plan prepared in accordance with the Z'berg-Nejedly Forest Practice Act of 1973 (Chapter 8 (commencing with Section 4511) of Part 2 of Division 4 of the Public Resources Code).
   b. Have been harvested for forest fire fuel reduction or forest stand improvement.
   c. Do not transport or cause the transportation of species known to harbor insect or disease nests outside zones of infestation or current quarantine zones, as identified by the Department of Food and Agriculture and the Department of Forestry and Fire Protection, unless approved by these agencies.

      Before January 1, 2007, eligible biomass facilities were permitted to use up to 25 percent fossil fuel annually on a total energy input basis consistent with the federal Public Utility Regulatory Policies Act of 1978 (Public Law 95-617) and Section 292.204, Subdivision (b), of Title 18 of the Code of Federal Regulations. However, the law as amended by SB 1250 contemplates restrictions on the use of fossil fuel for biomass facilities. Because existing solid-fuel biomass facilities may require at least a minimal amount of fossil fuel use to operate, 6 facilities participating in the ERFP are allowed to use up to 5 percent fossil fuel on a total energy input basis annually, and still have 100 percent of their generation eligible for ERFP funding. Facilities that use more than 5 percent fossil fuel will have their eligible generation reduced by the corresponding percentage of fossil fuel use. The total energy input of a facility shall be determined annually on a calendar year basis.

      For example, fossil fuel may be required for ignition, startup, testing, flame stabilization, and control uses, and to alleviate or prevent unanticipated equipment outages or emergencies.

Consistent with Section 292.204(b) of Title 18 of the Code of Federal Regulations, and expressed in millions of British Thermal Units (mmBTU).

Although facilities that use wind energy to generate electricity are eligible to participate in the ERFP, it is unlikely that any such facilities will qualify for funding unless market conditions change significantly.

In addition, facilities must be certified as eligible for California's RPS. Information is provided in the Energy Commission's *Renewables Portfolio Standard Eligibility Guidebook*.

3. In-State Location: A facility must be physically located in California, or located near California's border with its first point of interconnection to the Western Electricity Coordinating Council's (WECC) transmission grid located in California. Facilities that are located out-of state are not eligible for ERFP funding.
4. Operational Date: Facilities must have commenced commercial operations on or before September 26, 1996.
5. Facility Ownership: Facilities must not be owned by an electrical corporation as defined in Public Utilities Code Section 218 or a local publicly owned electric utility as defined in Public Utilities Code Section 9604(d).
6. Fixed Price Contract: A facility must not be selling its electrical generation under a fixed price power purchase contract that provides energy price payments above the facility-specific target price as determined by the Energy Commission. This applies to any facility with a power purchase contract that provides energy payments for a majority of the facility's generation, where the energy payments are based on a price per unit measure of electricity that (1) was known or ascertainable at the time the contract was entered into or amended, and (2) has an average fixed energy price greater than the applicable facility specific target price established by the Energy Commission.

Emerging Renewables Program

An estimated $282,195,000 is available.

The Emerging Renewables Program (ERP) was created to help develop a self-sustaining market for renewable energy systems that supply on-site electricity needs across California. Through this program, the Energy Commission provides funding to offset the cost of purchasing and installing new renewable energy systems using emerging renewable technologies.

The goal of the ERP is to reduce the net cost of on-site renewable energy systems to end-use consumers, and thereby stimulate demand and increased sales of such systems. Increased sales are expected to encourage manufacturers, sellers, and installers to expand operations, improve distribution, and reduce system costs.

Currently, four technologies are eligible for ERP funding. They include the following:

1. Photovoltaic - the direct conversion of sunlight to electricity.
2. Solar Thermal Electric - the conversion of sunlight to heat and its concentration and use to power a generator to produce electricity.
3. Fuel Cell - the conversion of sewer gas, landfill gas, or other renewable sources of hydrogen or hydrogen rich gases into electricity by a direct chemical process.
4. Small Wind Turbines - small electricity-producing, wind-driven generating systems with a rated output of 50 kilowatts or less.

New technologies may be added by petitioning the Energy Commission, through the appropriate Committee. Applicants must submit the proper documentation satisfying of all of the following criteria:

1. Financial assistance is required for these technologies to become commercially viable.
2. The technology must be commercially available with at least one vendor available for the sale of the system.
3. Vendors of any generating systems employing the technology must offer at least a five-year full warranty on the entire generating system.
4. The technology must show at least one year of demonstrated reliable, predictable, and safe performance by a full-scale facility using this technology under field conditions.
5. The available data must show that generating systems using the technology have a useful design life of at least 20 years.
6. The technology must be designed so that it can produce grid-connected electricity.
7. The technology represents a new electricity generating process not well represented among existing grid-connected renewable generating facilities, rather than some evolutionary or incremental improvements to renewable technologies used in existing renewable resource technology generating facilities (examples of such evolutionary or incremental improvements will be: a) an improved blade design for wind turbines, b) less expensive well drilling techniques for geothermal, or c) a more efficient burner design for a biomass plant).
8. The project must be designed exclusively for the purpose of producing electricity for on-site use or sale (excluding demonstration projects that may sell to one specific customer), in contrast to a research or demonstration facility, which is designed primarily for collecting additional research data.

New Renewable Facilities Program

Senate Bill 1078 and Senate Bill 107 direct the Energy Commission to “allocate and award supplemental energy payments” to “eligible renewable energy resources to cover above-market costs of renewable energy.” The California Public Utilities Commission (CPUC), in consultation with the Energy Commission, will determine what constitutes these above-market costs by establishing a market price referent.
The Energy Commission will award SEPs to eligible renewable energy facilities through the NRFP, which is allocated 51.5 percent of the renewable energy public goods charge (PGC) funds collected and

allocated under Senate Bill 12504 and Senate Bill 107. This amounts to approximately $386.25 million over a five-year period starting January 1, 2007. Approximately $347.625 million is available for SEPs from PGC funds collected over the prior five-year period, for a total of approximately $733.875 million. SEPs will be available to cover the appropriate above-market costs of renewable resources selected by retail sellers to fulfill their RPS obligations. For this guidebook, "retail sellers" includes Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), and Southern California Edison Company (SCE) and energy service providers (ESPs) and community choice aggregators (CCAs). PG&E, SDG&E and SCE are also referred to as "electrical corporations" or "Investor-Owned Utilities" (IOUs). The terms used here are defined in the glossary included in the *Overall Program Guidebook for the renewable Energy Program* (*Overall Program Guidebook)*. The NRFP provides grant funding in the form of production incentives, referred to as SEPs, to eligible renewable facilities for each kilowatt-hour of eligible electricity they generate. To qualify for funding, applicants must show that their proposed renewable facility meets a number of requirements as specified in Public Resources Code Sections 25740.5, 25741, and 25743 and Public Utilities Code Section 399.13.

First, these facilities must be certified by the Energy Commission as an eligible renewable energy resource for meeting the state's Renewables Portfolio Standard and must also be certified as being eligible for SEPs.

Second, these facilities must be selected either by PG&E, SCE, SDG&E or another electrical corporation in a competitive RPS solicitation approved by the CPUC, or by another retail seller, such as an ESP or CCA, as a result of a competitive solicitation process that the CPUC deems is consistent with its LCBF process. Additionally, SEPs for the latter must be reasonable in comparison to those paid under similar contracts with other retail sellers. Any contracts proposed by an electrical corporation are subject to CPUC approval. Retail sellers may award power purchase contracts for renewable power to selected facilities. Alternatively, a facility selected for a contract by a procurement entity that procures electricity on behalf of a retail seller and which has a CPUC-approved contract to sell the electricity to the retail seller may also be eligible for SEPs.

Third, the facilities must begin commercial operations or be repowered on or after January 1, 2005, or such later date as determined by the Energy Commission, with the exceptions that the applicable date for small hydroelectric facilities is January 1, 2006 and the applicable date for conduit hydroelectric facilities is January 1, 2007. Finally, the electricity generated must not be sold under certain long-term contracts with an in-state electrical corporation used on-site, or sold in a manner avoiding competitive transition charge payments. The *Renewables Portfolio Standard Eligibility Guidebook* provides more information on eligibility criteria for RPS certification and SEP eligibility. A procurement entity is defined as any person or entity that enters into an agreement to procure RPS-eligible electricity on a retail seller's behalf to satisfy the retail seller's RPS procurement obligations. A facility selected by a procurement entity may be eligible for SEPs. For a facility selected by a procurement entity to be eligible for SEPs, the facility must be certified as RPS eligible and eligible for SEPs and must agree to comply with all SEP requirements, including requirements pertaining to California's prevailing wage law. Furthermore, the procurement entity must annually report the amount of energy per month procured from the facility and sold to any California retail seller. The procurement entity must also agree to be subject to an Energy Commission audit. Some issues related to procurement entities may be decided in future CPUC proceedings, which may in turn require changes to this Guidebook.

Contracts between retail sellers and RPS-eligible facilities, procurement entities, or parties selling electricity for RPS-eligible facilities ("Sellers") will reflect the energy price bid or negotiated by the applicants in RPS solicitations or LCBF selection processes, measured in cents per kilowatt-hour. If the final negotiated price is above a benchmark price, or market price referent (MPR), established by the CPUC, then the Seller may be eligible to receive SEPs from the NRFP. The Seller must be the facility owner, a procurement entity, or the party with which a retail seller holds a contract for the purchase of power certified by the Energy Commission as SEP-eligible.

The law provides that "Supplemental energy payments awarded to facilities selected by a retail seller or procurement entity . . . shall be paid for no longer than 10 years, but shall, subject to the payment caps . . . [established by the Energy Commission], be equal to the cumulative above-market costs relative to the applicable market price referent at the time of initial contracting, over the duration of the contract with the retail seller or procurement entity."6 SEPs are calculated based on the difference between the final bid or negotiated price and the project-specific MPR. The law allows the Energy Commission to establish payment caps of various kinds (see below) to achieve the goals of the RPS and utilize PGC funds in the most efficient manner. 7 If a cap is established, a SEP award may be below the amount calculated as cumulative above market costs over the duration of the contract.

Contract negotiations occur on a case-by-case basis, so the Energy Commission is likely to receive SEP requests one at a time rather than collectively. However, awarding SEPs on a first-come, first-served basis without information on the potential demand for SEPs may result in inefficient use of public funds. Consequently, PG&E, SCE, and SDG&E must provide the Energy Commission with data to inform policy makers about the potential demand for SEP funds before the Energy Commission will consider awarding SEPs to winning bidders from these retail sellers' RPS solicitations. Within 30 days of the date that the CPUC adopts the MPR, each retail seller must provide data including the price and expected deliveries for each bid received. Additionally, the Energy Commission may require that each retail seller provide updated information for all bids on its short list to support the Energy Commission's analysis of the potential SEP demand. The Energy Commission will consider applications to hold the above mentioned data confidential pursuant to its regulations for confidential designation, California Code of Regulations, Title 20, Section 2501, et seq.

The Energy Commission will only consider a SEP application after a retail seller executes an eligible contract with a Seller. The final bid price must be above the MPR, and the contract must result from a CPUC-approved selection process with a Seller representing a SEP-eligible facility. The Energy

Commission anticipates that further refinement of this Guidebook may be needed in conjunction with CPUC decisions addressing procurement entity processes.

If the final bid or negotiated price per kWh is at or below the MPR, then the contract does not qualify for SEPs. When the retail seller files an advice letter to the CPUC requesting approval of the contract, the advice letter will identify whether or not the Seller is seeking SEPs.

If the final bid or negotiated price requires SEPs, then the Seller should apply to the Energy Commission for SEP funding, and the retail seller must provide supplemental information to the Energy Commission regarding the Seller's application. The Energy Commission will review the application to determine whether the facility qualifies for SEPs, the maximum amount of SEPs the facility qualifies for, and whether a cap on available SEPs is necessary. The Energy Commission will send the Seller, retail seller, and CPUC a Funding Confirmation Letter specifying the total amount of SEPs the Energy Commission anticipates awarding to the applicant. If the Funding Confirmation Letter specifies a lesser amount of SEPs than was requested by the Seller, then the retail seller and the Seller have an opportunity to renegotiate and restructure their contract terms based on SEP availability. When the Energy Commission issues a Funding Confirmation Letter, the Energy Commission will disclose information on its web site identifying the name of the Seller, the procurement entity (if any), the procuring retail seller, and the total anticipated SEP award amount.

Once the contract is approved by the CPUC and the facility completes any required environmental review for the renewable facility under the National Environmental Policy Act and/or the California Environmental Quality Act, the Energy Commission may enter into a grant agreement with the Seller. This grant agreement is referred to as a "Supplemental Energy Payment Award Agreement." The SEP Award Agreement will be considered for adoption by the Energy Commission at a business meeting and once adopted will be made publicly available. Once the renewable facilities are constructed and commence commercial operations, the applicants may submit monthly invoices to the Energy Commission to begin receiving SEPs under their NRFP grants.

Appendix G

The feasibility of three scenarios for biomass power generation project located in San Diego utilizing West Biofuels gasification technology was modeled using an Excel-based model adopted from a simple model available on the California Biomass Collaborative website. [40] The base model, developed by UC Davis professor Dr. Bryan Jenkins, allows for input of numerous variables impacting the cost of power production from a biomass gasification facility. The main output of the spreadsheet is the levelized annual cost of power based on the various inputs.

Significant categories of input variables include

- Capital costs (net of offsetting grant awards)
- Facility design capacity (net of offsetting parasitic electrical loads)
- Efficiencies of both the gasification and power generation portions of the plant
- Energy input (both of the biomass and any dual fuel)
- Moisture, ash, and carbon concentrations (for weight calculations of input fuel and facility waste)
- Sale price for waste heat, if waste heat sales are available
- Operating expenses including biomass fuel, labor and maintenance, land lease, and other categories of expenses
- Tax rates
- Incomes from other sources (such as capacity payments)
- Escalation factors for expenses
- Financing variables including debt to equity ratio, cost of debt and cost of equity
- Depreciation schedules
- Production tax credit schedules

The tab labeled "Gasifier_Economics" summarizes these variables, calculations utilizing the variables, and provides a resulting levelized annual cost.

Many changes to the initial model were made to facilitate the economic study conducted and discussed in this report. Certain minor changes were incorporated to facilitate ease of use. An additional tab, titled "Scenarios and Variables" was created to allow for changing multiple variables to simulate the different scenarios studied. In addition, many tabs were added to input detailed operating costs. The tabs, all labeled according to their associated expense category and including a summary tab (titled

[40] http://biomass.ucdavis.edu/calculator.html

[41] R. Cattolica defined the expected value for one of the probabilistic variables, the BTU value of the feedstock. Note that in utilizing this higher heating value as a variable, certain calculations utilizing syngas component gas concentrations were not used and associated calculations were over-ridden. Appropriate comments are made adjacent to the relevant spreadsheet cells noting this change

“Expenses Aggregation”), are found at the back of the Excel workbook. All of these tabs link to the corresponding expense cell in the “Gasifier_Economics” tab where calculations are performed. Additionally, a tab labeled “Summary” was added to provide both a table and graph of the resulting levelized annual cost and NPV for the scenarios studied. Finally, on all tabs where inputs are made (the “Scenarios and Variables” tab, all the expense category tabs, and the “Gasifier_Economics” tab) have corresponding comments typically indicating the source of the input value (often either a technical expert or literature reference) and any additional clarifying comments.

Beyond the simple changes to facilitate ease of use, several substantial changes were made to enable a more thorough study of the economics impacting a potential project. While certain stakeholders may prefer to understand the levelized annual power cost associated with a given project and target cost of money, others may prefer to a judge a project based upon an internal rate of return (IRR) or net present value (NPV) for a given power sale price. To enable this alternative project evaluation methodology, the tab labeled “Financials” was added which provides project returns and net present value for a given power sale price. This alternative evaluation methodology offers several advantages. First, power projects can have significant construction periods; the “Financials” tab enables delaying project cash flows for some time after capital expenditures to account for a construction period. While the current version used to model scenarios in San Diego used a simple time period to separate upfront capital spending from operating cash flows realized after the onstream date, the model could be upgraded to include more sophisticated modeling of construction costs, schedule, and financing. A second advantage of the “Financials” tab is the ability to segment project NPV into various components attributable to different aspects of the project. For example, the components of NPV reveal that the accelerated depreciation schedule available for certain facilities under PURPA regulations add significant value to the project. This type of information can be very valuable to project developers in allocating resources and negotiating with various project stakeholder and regulators. Finally, the “Financials” tab includes a section calculating cash flows to equity holders. This section can be modified as needed depending upon the exact terms of any debt financing used in the project. This contrasts with the calculations of levelized annual cost that utilizes capital recovery factors. The methodology used in calculating the levelized annual cost has an inherent assumption on the terms of debt repayment. Specifically, the calculation assumes a constant payment of debt interest plus debt principle over the life of the project in a manner similar to a home mortgage. It is possible, however, that a repayment schedule on a portion or all of the project debt financing would differ from this assumption. In the absence of definitive debt structure and associated cash management / short term investment strategy, however, this inherent assumption is sound. Once more definitive project financing is identified, however, the “Financials” tab provides the flexibility to more accurately calculate returns for equity holders.

The economic model was further enhanced by running Monte Carlo simulations using Crystal Ball modeling software. Per the sections at the top of the “Scenarios & Variables” tab, many of the key input variables were defined as either probabilistic variables, with a range and distribution input into the simulation, or parametric variables, which were systematically incremented to various agreed upon values.[41] The output of the simulation provided a probability distribution of various levelized annual costs and/or project NPVs. While many simulations were run during the course of the study, a sample report is included in the delivered model on the tab labeled “Simulation report”. Certain key distributions of levelized annual costs for various scenarios are reported in the main body of this report. Additionally, tables and associated charts provide project NPV over a range of each of the parametric variables, thereby significantly expanding the sensitivity analysis available to project developers. These tables and charts can be found at the bottom of the “Gasifier_Economics” tab.

Finally, as described in the body of this report, scaling factors were introduced to increase capital costs and certain operating cost with increasing output capacity of the facility. This enabled the sensitivity analysis around project size, specifically comparing a 3MW facility to a 5MW facility.