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Repowering Solid Fuel Biomass Electricity Generation

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Prepared by: California Biomass Collective, University of California, Davis

CALIFORNIA BIOMASS COLLABORATIVE

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PREFACE

The California Energy Commission Energy Research and Development Division supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

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Repowering Solid Fuel Biomass Electricity Generation is the interim report for the CREC Task 3.2.1.6 project (Contract Number 500-08-017) conducted by the California Biomass Collaborative. The information from this project contributes to the Energy Research and Development Division's Renewable Energy Technologies Program.

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ABSTRACT

Biomass contributes approximately 19 percent of California's renewable power and represents about two percent of California's total power mix. The objective of this study was to evaluate the current solid fuel biomass facilities that produce electrical energy from largely forest, urban and agricultural residues and to investigate the potential for additional or improved generation by repowering these facilities. This analysis investigated the potential for adapting (repowering) current combustion-based biomass power generation systems to other technologies, in particular integrated gasification systems either in simple cycle or combined cycle. The co-generation of heat was also considered for generating electricity. Several repowering scenarios were analyzed and the results indicated that economic opportunities exist for the biomass power industry to refurbish or replace generating equipment or to install new systems. A number of uncertainties were also identified, and the authors concluded that the lack of large-scale demonstrations, higher efficiency power systems, and specific performance and cost information made it difficult to resolve these uncertainties. Reductions in emissions would also allow for capacity expansions at existing sites, but additional research is needed to more fully assess individual sites as well as industry-wide potentials for economic and other performance benefits that might accrue through repowering.

Keywords: biomass, bioenergy, municipal solid waste (MSW), repowering, combined heat and power (CHP), integrated gasification combined cycle (IGCC)

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EXECUTIVE SUMMARY

Introduction

Biomass contributes more than 5.7 terrawatt hours (TWh) to California's in-state renewable power (about 19 percent of in-state renewable power and two percent of California's total power mix) (CEC 2010). Current operating biopower capacity is about 900 megawatts (MW), including approximately 550 MW of woody biomass solid fuel combustion, 280 MW of landfill gas-to-energy and 75 MW from wastewater treatment biogas (CBC 2011). It is estimated that there is sufficient in-state "technically" recoverable biomass to support another 2,800 MW of capacity or 21 TWh of electricity (Williams et al., 2008). "Technically" refers to biomass resources that can be sustainably recovered with minimal impacts to erosion, riparian zones, soil organic matter and other agronomic factors. There is no economic filter applied to the technical resource estimate. These values assume all biomass resources are used for power generation. Where used for fuel production or other applications, the quantity available for electricity generation is reduced.

Most biomass energy is derived from woody material, (including urban wood waste, forest product residue as well as agricultural residues), representing an estimated 3.6 TWh per year. There is a growing interest in using municipal solid waste (MSW) and applying co-digestion techniques at wastewater treatment facilities to generate electricity and renewable fuels.

At its peak, the California solid-fuel biomass industry generated 4.5 TWh per year of electricity (Morris G. , 2003). This was in the early 1990s, before deregulation. The existing facilities provide a significant portion of the state's renewable baseload renewable electricity. The continued economic feasibility of this source of renewable energy is uncertain, however, and improvements to increase overall performance and economic competitiveness would help to achieve the state's objectives for both near- and longer-term renewable energy development.

Bioenergy facilities provide baseload renewable energy but are also considered a beneficial disposal outlet for certain wastes. Non-market factors such as resource diversity, waste mitigation, and environmental impact are not necessarily fully incorporated into prices paid for energy from biomass facilities. Competition-based pricing does not favor solid-fuel biomass energy generation against wind and geothermal power within California's Renewable Portfolio Standard (RPS), or against natural gas and other sources in the electricity market.

The vast majority of California's solid fuel biomass power plants were built in the 1980s and are 25-30 years old. Because of nitrogen oxide (NOx) and particulate matter (PM) emissions from these systems (combustion boiler with steam Rankine power cycle), it will be difficult and expensive to site significant new capacity using this technology in California's non-attainment air quality regions.

Project Purpose

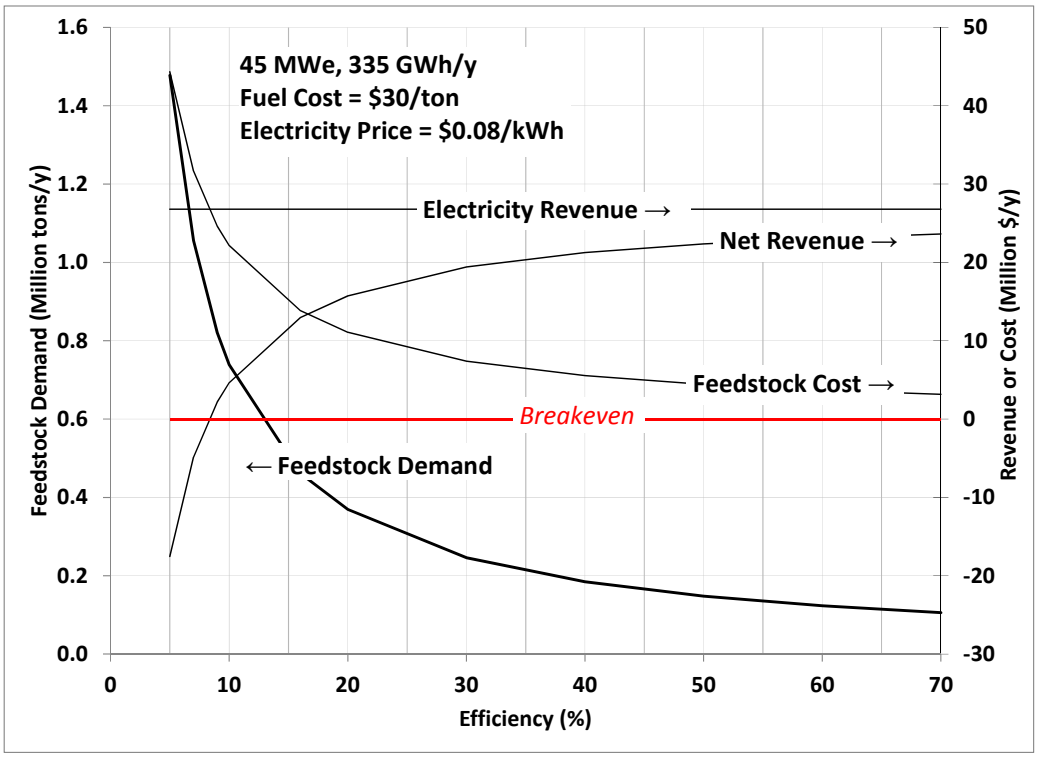
The objective of this study was to evaluate the current solid fuel biomass facilities that produce electrical energy from largely forest, urban and agricultural residues and to investigate the potential for additional or improved generation by repowering these facilities. This analysis

investigated the potential for adapting (repowering) current combustion-based biomass power generation systems to other technologies, in particular integrated gasification systems either in simple cycle or combined cycle. The co-generation of heat was also considered for generating electricity. Biochemical processes such as fermentation or anaerobic digestion were not addressed here nor were hybrid natural gas/solid biomass facilities or facilities that make biomethane/synthetic natural gas (SNG) for pipeline injection.

Project Results

The study found that the economic opportunity for repowering lies in part in the reduced feedstock demand associated with higher conversion efficiency, as shown in Figure ES 1. For a reference 45 megawatt electric (MWe) power plant fueled with biomass operating at an 85 percent capacity factor and generating 335 gigawatt hours (GWh) per year of electrical energy, an increase from 20 to 30 percent electrical efficiency reduced annual feedstock requirements by 123,000 dry tons and increased annual net revenues by $3.7 million for an electricity price of $0.08 per kilowatt hour (kWh) and feedstock cost of $30 per dry ton. This would also allow increased capacity and generation from the feedstock released to the market as well as potentially affecting feedstock market price due to changes in market demand. The incremental net revenue increased as fuel costs increased, so that at $60 per dry ton feedstock cost, the same increase in efficiency resulted in an annual net revenue increase of $7.4 million, although total net revenue is reduced at any efficiency due to the higher cost for feedstock, as shown in Figure ES 2. The effect was amplified if electricity prices increased as the conversion efficiency increased, or buffered if electricity prices decreased, as shown in Figure ES 3. At a $30 per dry ton feedstock cost, the increase in net revenue was $17.1 million as efficiency increased from 20 to 30 percent and the electricity price increased from $0.08 to 0.12/kWh, nearly five times the increase at a constant electricity price. A decline in electricity prices from $0.08 to 0.05/kWh at 20 percent efficiency would result in annual net revenues declining by $10.1 million. The loss in annual net revenue would be only $6.4 million if the same electricity price declines occurred while efficiency improved from 20 to 30 percent. These values only took into account the differences between electricity revenues and feedstock costs. Other factors included changes in capital, operating and maintenance, permitting, and other costs or benefits associated with any attempt to repower the facility, the effects of which were addressed in the economic assessments discussed later in the report.

Figure ES 1: Feedstock Demand and Changes in Annual Feedstock Costs and Electricity Revenues with Conversion Efficiency for a Reference 45 MWe Biomass Power Plant



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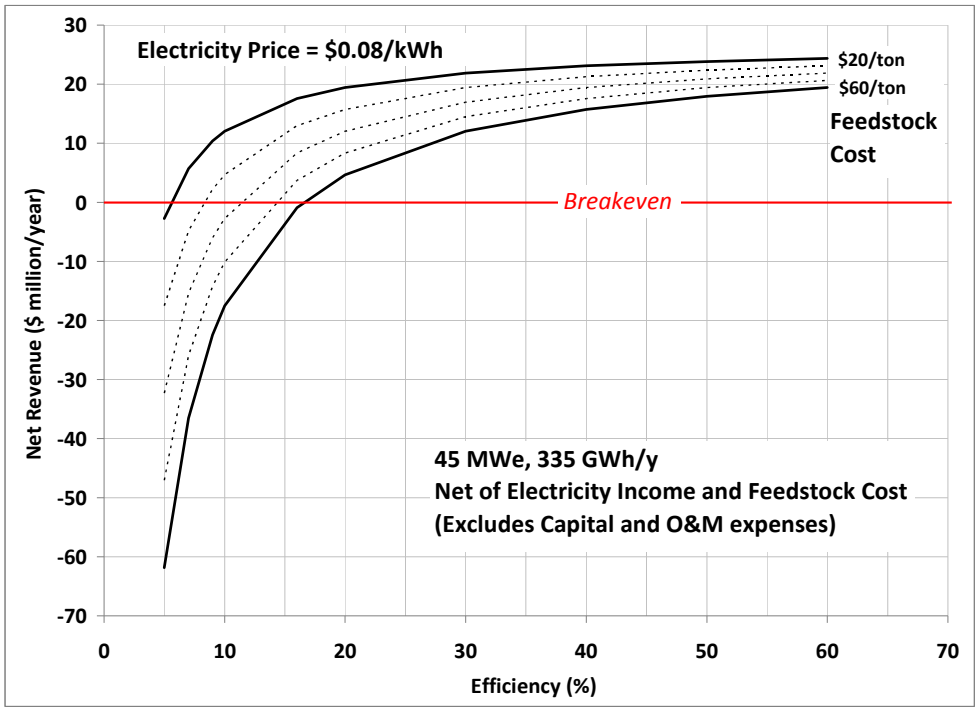
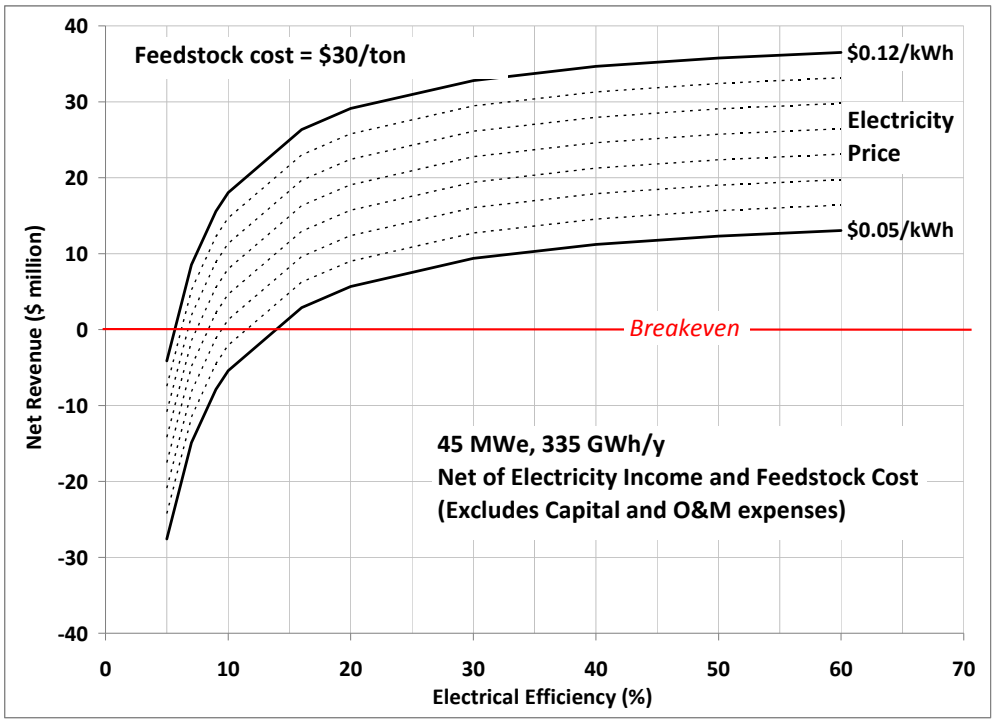


Figure ES 3: Net of Annual Electricity Revenue and Feedstock Cost with Efficiency for a 45 MWe Reference Biomass Power Plant. Electricity Price Increment between Curves is $0.01/kWh.



Six repowering scenarios were considered, including a base case:

- Base case (boiler replaced with new boiler).
- Base case plus heat recovery.
- Gasifier with single-cycle gas turbine.
- Integrated gasification combined cycle (IGCC).
- Integrated gasification and fuel cell (IGFC).
- Integrated gasification and fuel cell combined with steam bottoming cycle (IGFCCC).

The capital cost assumptions and the estimated levelized cost of energy (LCOE) by scenario are summarized in Table ES 1. The scenario with the lowest capital cost (base case at $1427/kW) had a mid-range electricity generation cost (LCOE, constant $0.048 per kWh). The lowest LCOE was the base case with combined heat and power (CHP) at $0.038 per kWh where heat sales more than compensated for the additional capital cost of the CHP equipment.

Table ES 1: Summary of Capital Cost and LCOE for Repowering Scenarios

	Capital Cost, Installed ($/kW net)	LCOE (Current, $/kWh)	LCOE (Constant, $/kWh)
Base Case	1427	0.055	0.048
Base Case + CHP	1549	0.044	0.038
Gasifier w/ GT	1698	0.059	0.051
BIGCC	1801	0.047	0.041
IGFC	3033	0.074	0.064
IGFCCC	3137	0.069	0.060

The highest LCOE scenarios were associated with gasifier-to-fuel cells ($0.64 and $0.60 per kWh) where the capital cost increment was more than the associated efficiency improvement. These results were preliminary pending scrutiny of the literature and capital cost assumptions for the scenarios. For instance, conservative assumptions on system efficiencies for the combustion pathways were used for both electricity and CHP. Assessing the sensitivity of costs to efficiencies in the combustion scenarios as well as the others may change the rank ordering of these scenarios, at least by the criterion of LCOE. A quantitative discussion of emissions for each scenario (and comparisons to business as usual – not repowering) would help inform scenario outcomes and offer insight for potential health and air-shed improvements. The economic potential of selling emissions reductions on offset markets needs to be analyzed for impacts on LCOE in scenarios with emissions reductions.

The analysis of repowering scenarios suggested that economic opportunities exist for the biomass power industry in addressing refurbishment or replacement needs for generating equipment or for installing new systems. A number of uncertainties surrounded this issue, especially as large-scale demonstrations are mostly lacking alternative and potentially higher efficiency power systems and specific performance and cost information have yet to be developed. Implementing CHP where possible in facilities currently generating electricity only had some clear LCOE advantages if heat was consistently valued with heat from purchased natural gas. IGCC could also realize cost advantages in comparison with Rankine cycle combustion power plants, but the difference in estimated LCOE ($0.041 vs. 0.048 per kWh) was in a range where significant amounts of new information on commercial scale cost and performance was required to gain substantial confidence in the potential benefits associated with this type of repowering. Integrated fuel cell systems may also offer substantial efficiency advantages, but estimated capital costs resulted in LCOE above both the reference Rankine cycle and IGCC systems. Reductions in emissions would also allow for capacity expansions at existing sites, but additional research is needed to more fully assess individual sites as well as industry-wide potentials for economic and other performance benefits that might accrue through repowering.

Project Benefits

This project investigated the potential for additional or improved generation by repowering solid fuel biomass facilities. If the scenarios analyzed in this study were implemented, additional electrical generation would be produced from biomass energy, which would reduce greenhouse gas emissions that cause climate change and also reduce other emissions that cause air pollution and adverse health effects.

CHAPTER 1: Introduction

With an increasing demand for energy - renewable energy generation is critical to allow for a sustainable energy future. The California Renewable Portfolio Standard (RPS, SB 1078[1] and following legislation) was implemented to ensure California would lead in the development of renewable power generation. The RPS requires investor-owned utilities, electric service providers, and community choice aggregators to procure 33 percent of electricity from eligible renewable energy resources by 2020. To support biomass as a renewable source, the Governor's executive order EO-06-06 calls for a minimum of 20 percent of the renewable electricity under the RPS come from biopower. This executive order carries no force of law, and so does not mandate this level of generation from biomass but constitutes a continuing interest in renewable electricity from this resource.

As part of the RPS and the future higher penetration of renewables in the electricity generation mix, biomass is also useful because it can serve as a source of baseload power to help stabilize the electricity transmission and distribution grid handling high levels of intermittent solar and wind based generation.

Biomass contributes more than 5.7 TWh to California's instate renewable power (about 19 percent of in-state renewable power and 2 percent of full California power mix) (CEC 2010). Current operating biopower capacity is about 900 MW (including approximately 550 MW of woody biomass solid fuel combustion, 280 MW of landfill gas-to-energy and 75 MW from wastewater treatment biogas) (CBC 2011). It is estimated that there is sufficient in-state 'technically'[2] recoverable biomass to support another 2,800 MW of capacity or 21 TWh of electricity (Williams et al., 2008). These values assume all resource is used for power generation. Where used for fuel production or other applications, the quantity available for electricity generation is reduced.

While most biomass energy is derived from woody material, estimated 3.6TWh/y (including urban wood waste, forest product residue as well as agricultural residues), there is a growing interest in using municipal solid waste (MSW) and applying co-digestion techniques at wastewater treatment facilities to generate electricity and renewable fuels.

At its peak, the California solid-fuel biomass industry generated 4.5 TWh/y of electricity (Morris G. , 2003). This peak occurred in the early 1990s, before the electric utilities were deregulated. The energy generated from the biomass industry has since continued to decline with slight fluctuations based on largely on economic feasibility.

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[1] http://www.energy.ca.gov/portfolio/documents/documents/SB1078.PDF

[2] Technical biomass resource is that which can be sustainably recovered with minimal impacts to erosion, riparian zones, soil organic matter and other agronomic factors. There is no economic filter applied to the technical resource estimate.

The existing facilities provide a significant portion of the state's renewable base load renewable electricity. The continued economic feasibility of this source of renewable energy is uncertain, however, and improvements to increase overall performance and economic competitiveness would be beneficial in helping to achieve the state's objectives for both near and longer term renewable energy development.

Although bioenergy facilities are also considered a beneficial disposal outlet for certain wastes, non-market factors such as resource diversity, waste mitigation, and environmental impact are not necessarily fully incorporated into prices paid for energy from biomass facilities. Competition-based pricing does not at present favor solid-fuel biomass energy generation against wind and geothermal power within the RPS, or against natural gas and other sources in the electricity market.

In addition to waste mitigation, carbon neutrality serves as an advantageous aspect of bioenergy. Biomass and biogas resources that are converted into energy might otherwise be burned or flared without useful energy production. The value of removing selected biomass materials from forests to reduce the risk of wildfire has been suggested to yield an economic advantage, adding economic growth to rural communities while reducing the costs associated with wildfires (predominantly avoided costs of firefighting, (Overend, 1997)).This does not include the avoided emissions costs associated with wildfires (Becker, et al., 2009; Mason, et al., 2006). If carbon trading were implemented, the carbon offsets from utilizing the waste streams compared to their "alternate fates" would improve economics for biomass facilities.

The objective of this study is to evaluate the current solid fuel biomass facilities that produce electrical energy from largely forest, urban and agricultural residues and investigate the potential for additional or improved generation by repowering these facilities.

The vast majority of the state's solid fuel biomass power plants were built in the 1980's and are 25-30 years old. Because of NOx and particulate matter (PM) emissions from these systems (combustion boiler with steam Rankine power cycle), it will be difficult (and expensive) to site significant new capacity using this technology in California's non-attainment air quality regions.

This analysis investigates the potential for adapting (repowering) current combustion-based biomass power generation systems to other technologies, in particular integrated gasification systems either in simple or combined cycle. The generation of heat is also considered in the context of combined heat and power applications, again with the principal consideration being the generation of electricity. Biochemical processes such as fermentation or anaerobic digestion are not addressed here. Co-firing with coal is a well investigated option for the utilization of biomass in power generation. The California power grid is, however, dominated by natural gas. Natural gas is currently cofired with biomass in direct combustion (solid fuel) facilities; to cofire biomass in natural gas thermal power stations would require specific redesign of most facilities, especially combined-cycle facilities, where the biomass is not first converted to a biomethane or substitute natural gas (SNG) for pipeline injection. This option is also not considered in the analyses here.

Specifically, this report focuses on the repowering of biomass solid fuel electricity generation facilities. Hereafter 'repowering' is used to describe the redesign and conversion of a biopower facility by one the following options: replacing the existing boiler, adding an additional cycle or new prime mover, and/or adding gasification units. The focus on existing facilities is central to this report, as idle or operating biopower facilities have already received their operating permits and, in most cases, identified sustainable sources of biomass for the feedstock. Additionally, many biomass facilities may have a long term contracts for feedstock supply. Repowering is meant to decrease emissions, improve feedstock conversion efficiencies and economic competitiveness, and potentially increase generation capacity and energy.

The economic opportunity for repowering lies in part in the reduced feedstock demand associated with higher conversion efficiency (Figure 1). For a reference 45 MWe power plant fueled with biomass operating at an 85 percent capacity factor and generating 335 GWh per year of electrical energy, an increase from 20 to 30 percent electrical efficiency would reduce annual feedstock requirements by 123,000 dry tons and increase annual net revenues by $3.7 million for an electricity price of $0.08/kWh and feedstock cost of $30/dry ton. This would also allow increased capacity and generation from the feedstock released to the market as well as potentially affecting feedstock market price due to changes in market demand. As fuel costs increase, the incremental net revenue does as well, so that at $60/dry ton feedstock cost, the same increase in efficiency results in an annual net revenue increase of $7.4 million, although total net revenue is reduced at any efficiency due to the higher cost for feedstock (Figure 2). The effect is amplified if electricity prices increase as the conversion efficiency increases, or buffered if electricity prices decrease (Figure 3). At a $30/dry ton feedstock cost, the increase in net revenue is $17.1 million as efficiency increases from 20 to 30 percent and electricity price increases from $0.08 to 0.12/kWh, nearly 5 times the increase at constant electricity price. A decline in electricity prices from $0.08 to 0.05/kWh at 20 percent efficiency would see annual net revenues decline by $10.1 million. Were the same electricity price decline to occur while efficiency improved from 20 to 30 percent, the loss in annual net revenue would be only $6.4 million. These values account only for the differences between electricity revenues and feedstock costs. Beyond these are changes in capital, operating and maintenance, permitting, and other costs or benefits associated with any attempt to repower the facility, effects of which are addressed in the economic assessments detailed later in the report.

Figure 1: Feedstock Demand and Changes in Annual Feedstock Costs and Electricity Revenues with Conversion Efficiency for a Reference 45 MWe Biomass Power Plant

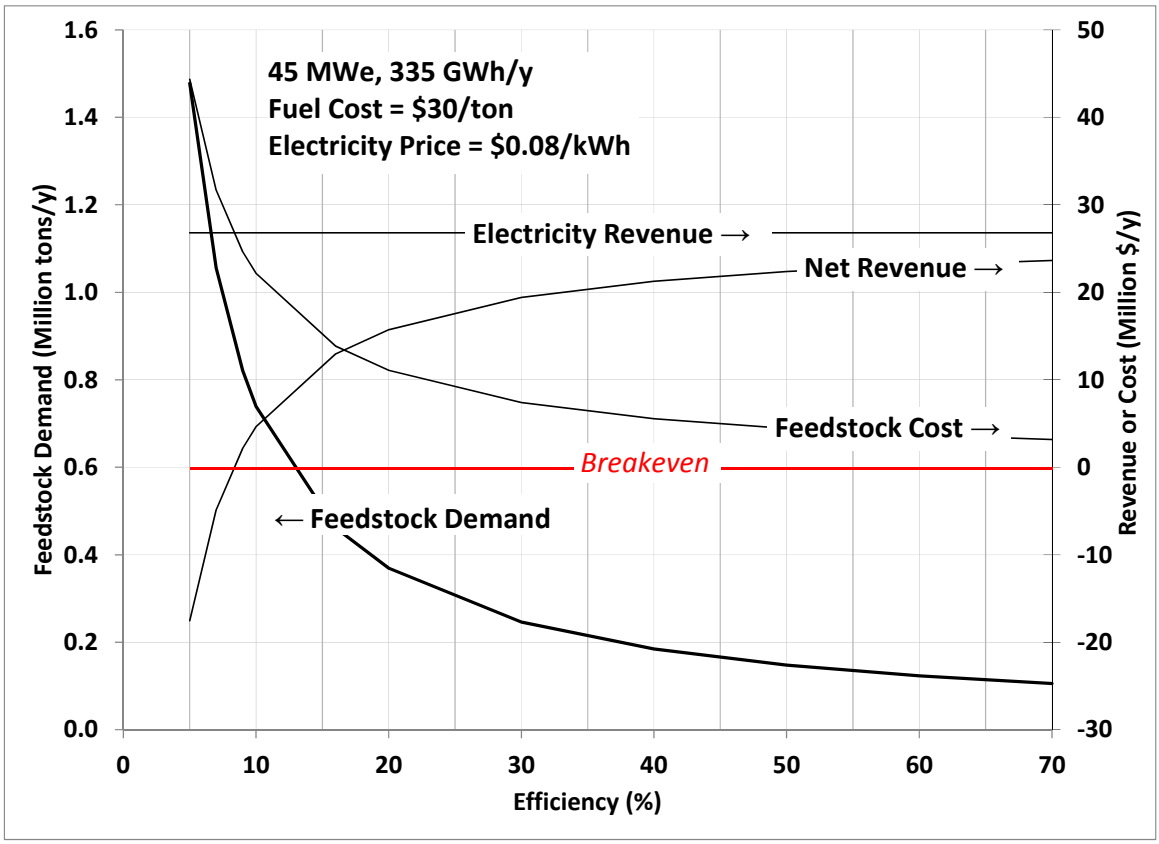


Figure 2: Net of Annual Electricity Revenue and Feedstock Cost with Efficiency for a 45 MWe Reference Biomass Power Plant. Feedstock Cost Increment between Curves is $10/dry ton.

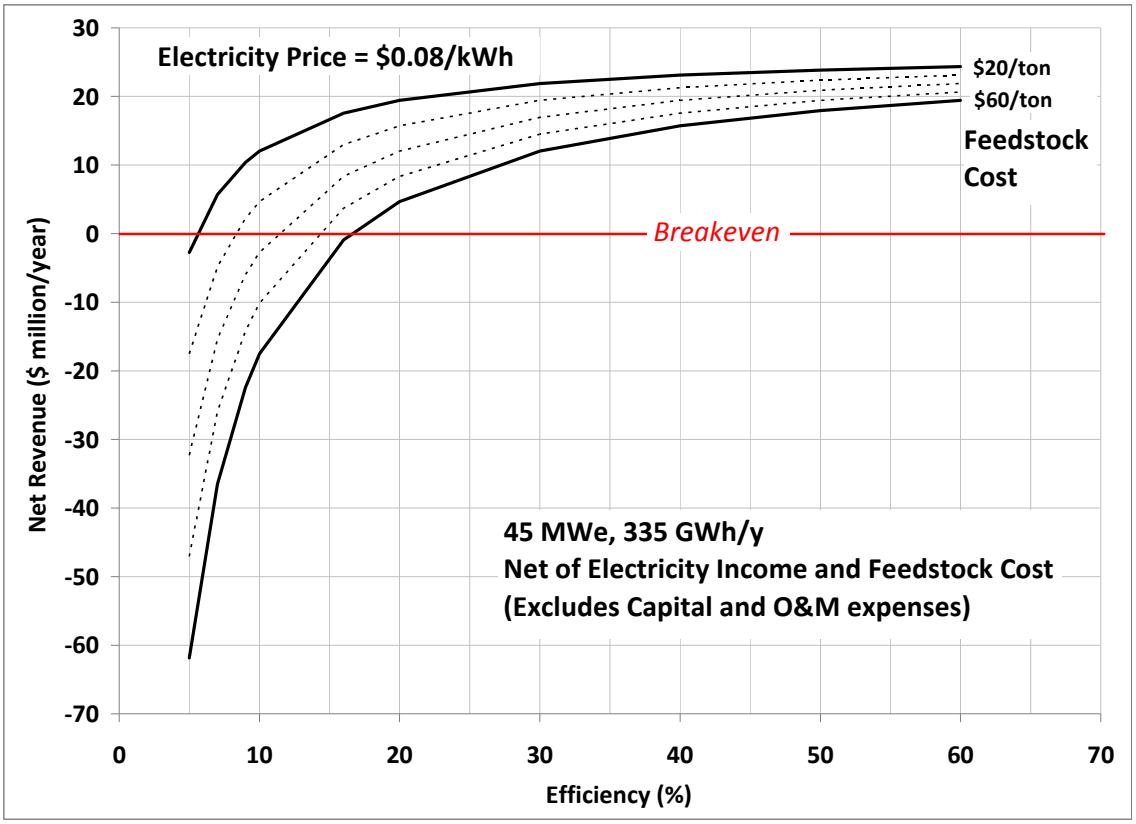
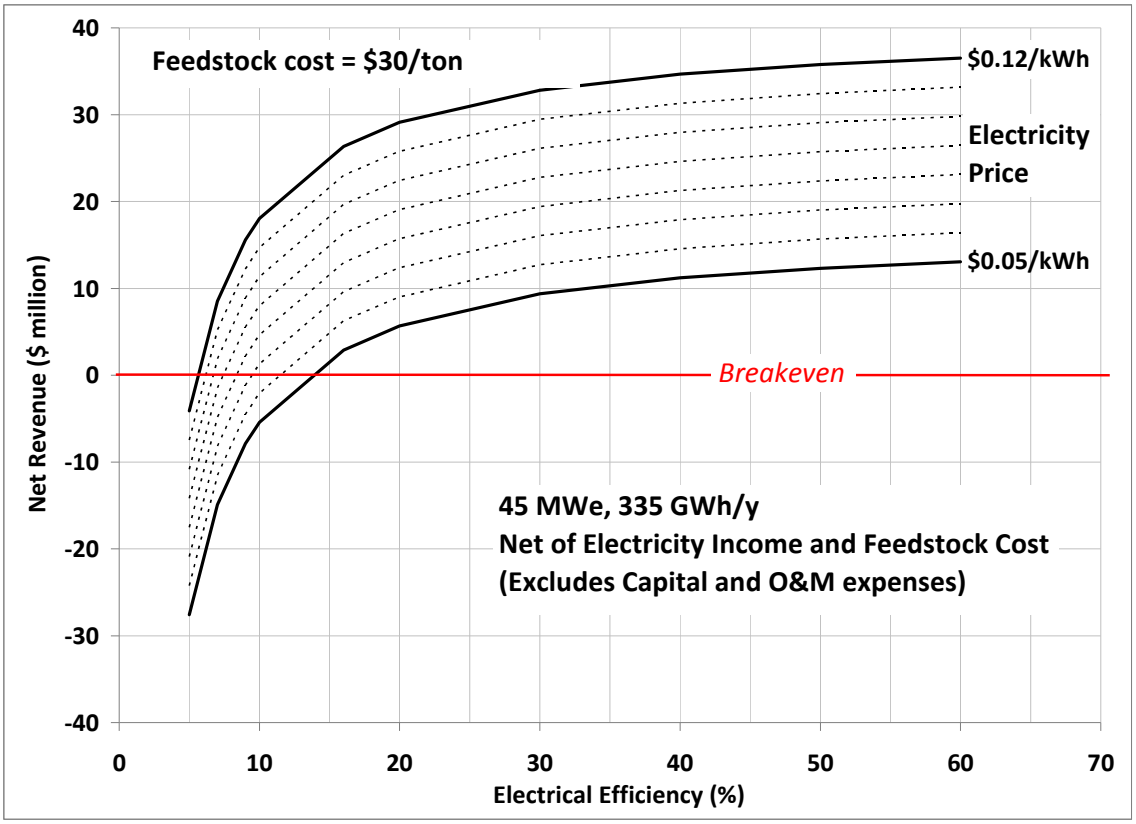


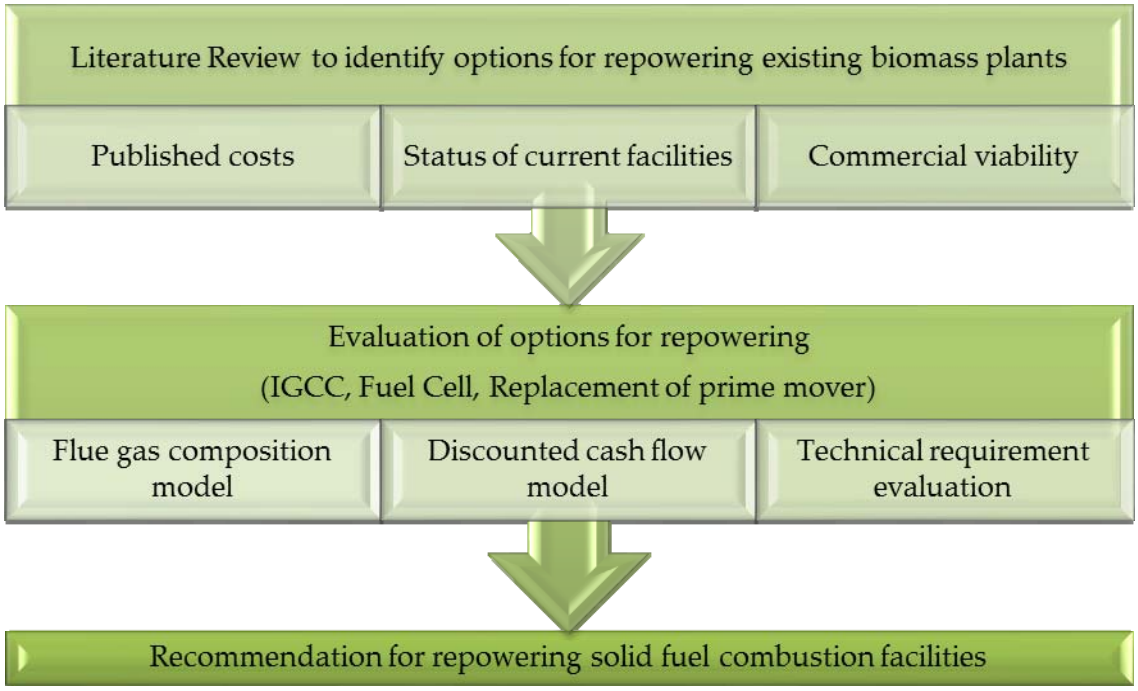
Figure 3: Net of Annual Electricity Revenue and Feedstock Cost with Efficiency for a 45 MWe Reference Biomass Power Plant. Electricity Price Increment between Curves is $0.01/kWh.



CHAPTER 2:
Literature Review

The current state of the industry, definition of repowering and capabilities to repower, costs associated with bioenergy and repowering, permitting issues, and available technologies are highlighted in the following sections as found in literature. The background provides the basis for the analysis of the applicable pathways for power generation by solid fuel biomass conversion in California (Figure 4).

Figure 4: Assessment Methodology



2.1 Current status of the Industry

The current biomass industry in California can be attributed to the federal Public Utilities Regulatory Policy Act (PURPA) of 1978. Before PURPA, most solid biomass waste was burned or otherwise disposed of without the capture of useable energy(Morris, 2000). PURPA did this by requiring that utilities purchase power provided by qualifying independent power producers at the utility "avoided cost"(Morris, 2000), essentially the cost for the next increment of electrical energy needed by the utility that would be provided instead by alternative sources (e.g., natural gas). Due to high fossil fuel prices and supportive renewable legislation in California, the 1980s to early 1990s is known as the "growth period" for biomass facilities and laid the foundation for the utilization of approximately 6.5 million tons of waste(Morris , 2000). The primary economic incentives for the growth of the biomass power sector in the state was Standard Offer 4 contracting from the utilities that provided for ten year contracts with

escalating prices for electricity. Due to oversubscription from multiple generation sources, SO4 contracting was suspended by the CPUC in 1985, although construction of facilities holding SO4 contracts continued for a number of years. The electricity sector in California was restructured by law in 1996 (AB 1890), and few financial incentives for additional generation capacity have existed since then, and increasingly stringent air quality standards have made permitting for solid-fuel direct combustion facilities, among others, more difficult. Since 1996, the biomass industry has remained relatively static.

There are twenty-seven operating solid-fuel biopower facilities in California (including one that co-fires with coal or petcoke), six idle facilities, six proposed or actively converting from fossil to biomass fuel and six that are not operational or dismantled (Tables 1 and 2). Operating facilities account for more than 580 MW of net capacity, while nearly 90 MW of capacity is idle (Table 2).

Table 1: Status of Solid Fuel Biomass Facilities in California

Name	City	Net Capacity (MW)	CHP	Status
Burney Forest Power	Burney	31	yes	Operational
Chowchilla	Chowchilla	12	no	Operational
Collins Pine Co.	Chester	12	yes	Operational
Colmac	Mecca	47	no	Operational
Delano Energy Inc.	Delano	49	no	Operational
DG Fairhaven	Fairhaven	18	no	Operational
Dinuba Energy	Dinuba	12	no	Operational
Honey Lake Power	Wendel	19 [a]	no	Operational
Madera Power LLC	Firebraugh	25	no	Operational
Mendota Biomass Power	Mendota	25	no	Operational
Pacific Oroville	Oroville	18	no	Operational
Pacific Ultrapower Chinese Station	Jamestown	20	no	Operational
Rio Bravo Fresno	Fresno	25	no	Operational
Rio Bravo Rocklin	Rocklin	25	no	Operational
Roseburg Forest Products	Weed	12	yes	Operational
Scotia Biomass	Scotia	28	yes	Operational
Sierra Power Corp.	Terra Bella	9	yes	Operational
SPI Anderson	Anderson	4	yes	Operational
SPI Burney	Burney	20	yes	Operational
SPI Lincoln	Lincoln	18	yes	Operational
SPI Quincy	Quincy	20	yes	Operational
SPI Standard	Sonora	6	yes	Operational
Tracy Biomass Plant	Tracy	19	no	Operational
Wadham	Williams	25	no	Operational
Wheelabrator Shasta	Anderson	50	no	Operational
Woodland Biomass Power Ltd	Woodland	25	no	Operational
Air Products Stockton	Stockton	9 [b]	yes	Operational/ co-fire
Kiara solar (formerly Wheelabrator Hudson)	Anderson	6	yes	Restart
Big Valley Biomass	Bieber	7.5	no	Idle
Blue Lake Power	Lake	11	no	Idle
Burney Mountain Power	Burney	11	no	Idle

Name	City	Net Capacity (MW)	CHP	Status
Imperial Valley Resource Recover	Brawley	18	no	Idle
Merced Power (El Nido)	El Nido	10	no	Idle
Mt. Lassen Power	Westwood	11	no	Idle
SPI Loyalton	Loyalton	20	no	Idle
Buena Vista Power	Ione	18	no	Converting to biomass
DTE Stockton	Stockton	45	yes	Converting to biomass
Mt. Poso Cogeneration	Bakersfield	44	yes	Converting to biomass [c]
SPI Anderson Project	Anderson	31	yes	Proposed New build
Rio Bravo Jasmin	Bakersfield	40	yes	Proposed Conversion to biomass
Rio Bravo Poso	Bakersfield	40	yes	Proposed Conversion to biomass
Mesquit Lake Resource Recovery	Brawely	18.5	no	Not Operational (possible restart)
Susanville	Susanville	12.5	no	Not Operational (possible restart)
Sierra Biomass	Auberry	7.5	no	Not Operational
Soledad Energy	Soledad	13	no	Not Operational
Diamond Walnut	Stockton	4.5	no	Dismantled
Freshwater Pulp	Samoa	50	yes	Dismantled

Notes: a) Capacity is 32MW, currently operating at 19MW. b)Facility is 45MW net, 9 MW from 20% biomass (cofire w/ coal, petcoke, TDF). c) Initially will cofire biomass and coal/petcoke, then plans 100% biomass.
Source: Mayhead, http://ucanr.org/sites/WoodyBiomass/Woody_Biomass_Utilization_2/California_Biomass_Power_Plants/ (2012)

Table 2: Summary of California Solid Biomass Power Facility Status

Status Category	No. of Facilities	Capacity (MW)
Operational	27	583
Undergoing Restart	1	6
Idle	7	88.5
Converting to Biomass	3	107
Proposed New or Conversion	3	111
Not Operational or Dismantled	6	106

2.2 Repowering Defined

Repowering includes upgrading an existing facility by increasing boiler efficiency, replacing/improving the prime mover, adding an additional cycle, or replacing the entire system with a different technology such as gasification with combined cycle power generation. Other equipment on site which did need upgrading would continue to be used (e.g., fuel and ash storage and handling, components of grid connection, water treatment and conditioning, etc.).Repowering allows for continued utilization of capital invested in existing equipment.

Considerations of repowering include(Black & Veatch, 2010):

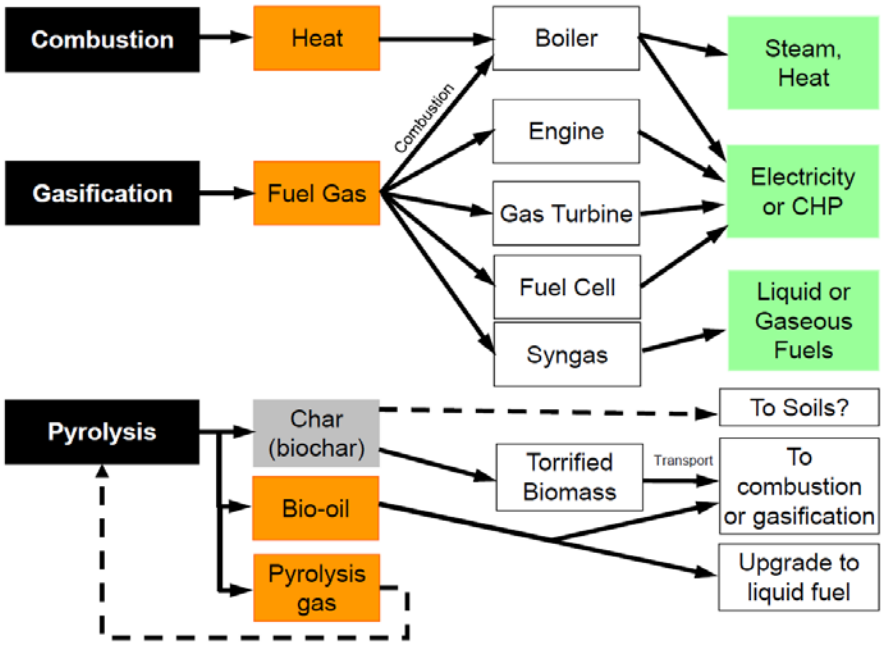
- Condition and expected life of existing systems,
- biomass fuel composition,
- resource availability,
- performance impacts, and
- emissions and permitting .

Repowering can extend the life of a facility and may be less costly than building a new plant because portions of the plant infrastructure can continue to be used, power contracts may not need renegotiating and it may be simpler to modifiy existing permits than to obtain new permits (Phillips, 2011). The potentials of different pathways for repowering are investigated in section 4 of this report.

2.3 Technologies

Bioenergy products include heat, power, or fuels (such as renewable diesel, SNG, or hydrogen). A wide range of conversion options exist, some commercial, some developmental, and some only in the research stages. Thermochemical conversion pathways for solid biomass (combustion, gasification and pyrolysis) are illustrated in Figure 5. Not shown are co-firing pathways which include solid biomass cofired with other solid fuels (coal, petcoke, MSW, RDF), gasified biomass product gas co-fired with natural gas (or fired in a gas burner into a solid-fuel boiler), solid or biomass product gas fired in the HRSG (or separate boiler) for heat addition in a natural gas combined cycle facility.

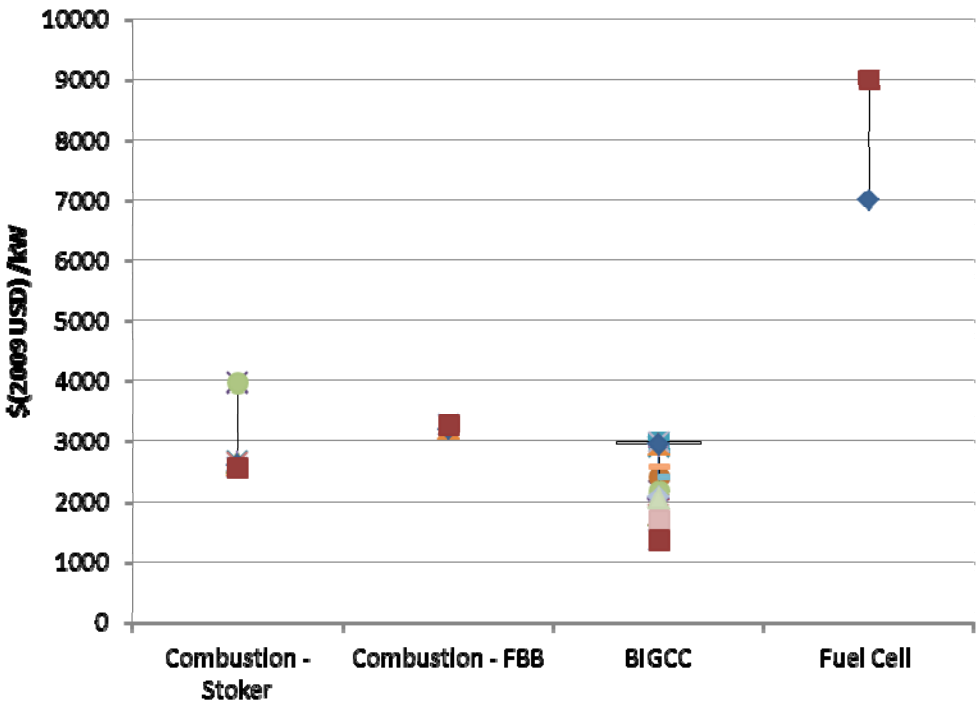
Figure 5: Thermochemical Conversion Pathways of Solid Fuel Biomass Feedstock[3]



[3] Source: Williams (2010).

Instant costs[4] of gasification and combustion pathways from literature are shown in figure 6.Based on literature data direct combustion with stoker boilers carries one of the higher instant costs, although uncertainties associated with this finding are high. This could mainly be attributed to lower efficiencies of feedstock conversion in a stoker boiler compared to projected costs for biomass integrated gasifier combined cycle systems (BIGCC), consistent with cost trends from the IEA (IEA Bioenergy, 2009). At larger scales, the gasifier costs are estimated mainly from smaller demonstration plants as further discussed in the section below. Similarly, no commercial biomass-based fuel cell system of substantial capacity equivalent to the upper ranges of existing combustion based systems has been demonstrated, so the costs reported are also estimates. In this way, both gasification and fuel cell technology suffer from large uncertainties associated with estimated instant costs not yet validated by full-scale commercial operation.

Figure 6: Instant Costs of Various Power Generation Pathways from Literature[5]



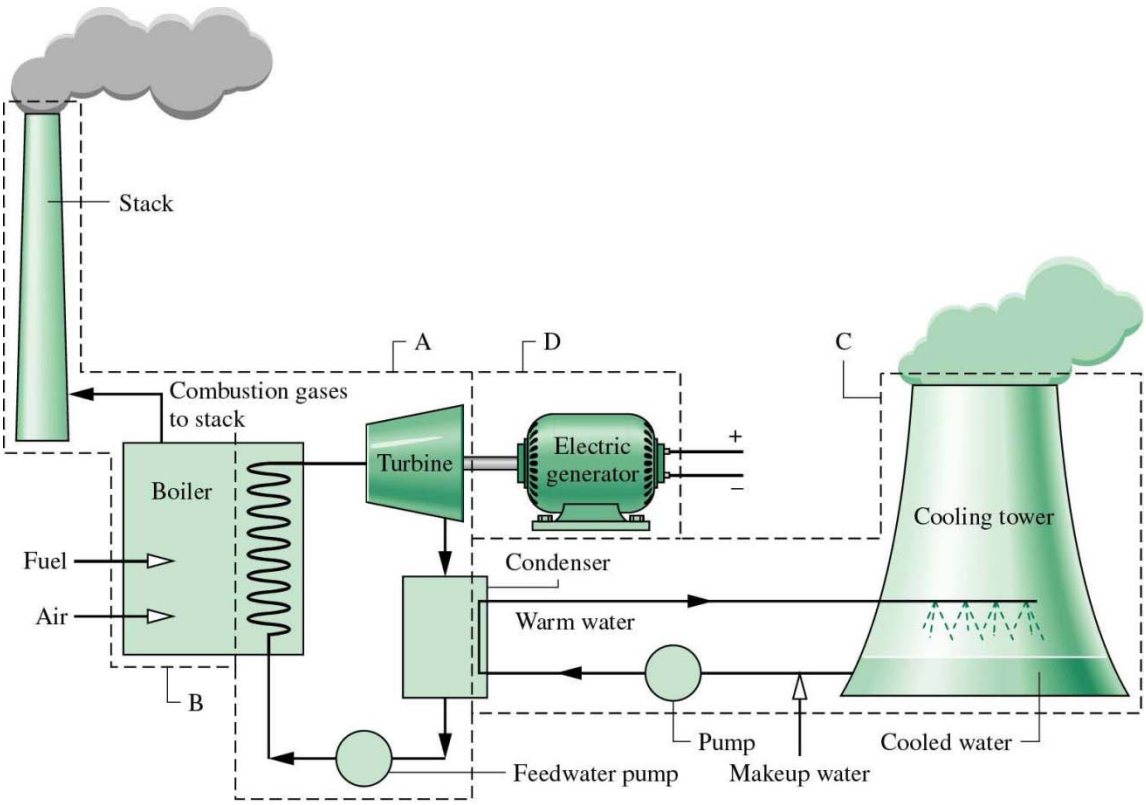
[4]Instant Cost, sometimes referred to as *overnight cost*, assumes that the plant can be built instantly (includes component, engineering, permitting, connection costs). Installed Cost accounts for the sales tax and the construction loan.

[5]Antonio C. Caputo, 2005; California Energy Commission, 2009; Craig & Mann, 1996; Los Angeles County Sanitation District, 2009; McDannel M. W., 2007; Rhodes, 2005; Rodrigues, 2003; Searcy, 2009; Weyerhaeuser Co, 2000; Williams R. L., 1996; Wiltsee, 2000.

2.3.1 Direct-Fired Biomass or Direct Combustion

Direct combustion of biomass for power generation involves the oxidation of biomass with excess air to produce heat. In current electricity generating applications, the Rankine cycle is used almost exclusively with feedstock combustion raising high pressure steam in a boiler (Figure 7). The steam is then expanded through a turbine connected to a generator for electricity generation. Modern facilities primarily use traveling-gate , fluidized bed, or suspension fired furnaces to convert the feedstock into hot combustion gas.

Figure 7: Diagram of Generic Rankine Cycle Solid-Fuel Combustion Plant[6]



System efficiency can be improved by increasing steam temperature and/or pressure, pre-heating combustion air and boiler feedwater (by heat exchange with boiler flue exhaust) improving air flow, optimizing boiler insulation, maintaining a low inlet air flow, or decreasing furnace exit gas temperature. Most facilities incorporate these efficiency measures but boiler-tube materials limit maximum steam temperature and pressure (tube life and strength limited by temperature and temperature dependent corrosion). Most energy losses are due to heat losses from the boiler or incomplete combustion(Cheng, 2010). Stoker boilers are simple and more flexible in fuel particle size, thus decreasing fuel preparation costs, but are being replaced by higher efficiency fluidized bed boilers (Cheng, 2010). Bubbling fluidized beds (BFB) and

[6] Western Virginia University (http://www.mae.wvu.edu/~smirnov/mae320/notes.html/)

circulating fluidized beds (CFB) are more flexible in fuel moisture content than stokers; however, they require a more stringent particle size and ash controls.

Devices (or prime movers)used for power generation from biomass combustion include steam turbines, steam piston engines, steam screw engines, steam turbines in combination with an organic Rankine cycles (ORC), external Brayton cycles (externally fired gas turbine), or Stirling engines. The steam screw engine and external Brayton cycle have not been proven for large combustion processes. Steam piston engines (which have relatively low efficiency) and steam turbines with ORC are used for smaller (less than 1.5 MWe) applications, along with current demonstrations of Stirling engines (Koppejan, 2008). Steam Rankine cycles are generally utilized in solid-fuel combustion facilities larger than ~ 5 MWe. Gas turbines are further described in section 2.5.2.

2.3.2 Biomass Gasification

Biomass-based integrated gasification combined cycle (IGCC or BIGCC) is attractive for biomass power production because it offers higher net efficiencies than Rankine steam cycles. Components of the gasification system include fuel receiving, sizing, preparation (and possibly drying), a gasifier, gas cleaning and conditioning(Craig & Mann, 1996). An integrated gasifier combined cycle utilizes a topping cycle with gas turbine-generator and bottoming cycle utilizing a heat-recovery steam-generator (HRSG) and steam turbine-generator—using what would have been waste heat to increase efficiency. Searcy (2009) indicates that where a biomass resource or plant capacity is fixed, BIGCC can produce power at a lower price than direct combustion when the feedstock price is relatively high (e.g. $270/MWh for a 4500 BDT/day processing cost). This conclusion is highly uncertain given the lack of commercial scale demonstration and reflects the value of high conversion efficiency with expensive feedstock.

Gas turbines for power generation up to about 100 MW are derived from aircraft propulsion turbines (so called aerodervitive turbinesincluding the LM 1600 (S&S), LM 2500 (GE), and PGT 25 (Nuovo) (Rodrigues, 2003). GE Energy markets a turbine for syngas from IGCC[7]. With steam injection, larger turbines can produce electricity at up to 40 percent efficiency (simple cycle, Williams,1996). Biomass gasification systems can enable utilization of gas turbines (also with combined steam cycle), which potentially can improve efficiencies compared to single cycle steam turbines (Electric Power Research Institute, 1995). Gas conditioning, including the removal of byproduct tar, alkali, and other contaminants thatcan be harmful to engines,is a significant issue for gasification systems (Maniatis, 2002).

2.3.2.1 BIGCC History

Though several coal fired IGCC systems exist such as Buggenum IGCC in the Netherlands producing 250 MWe (Negro, 2008), BIGCC systems are still develomental. The US DOE biomass power program supported development work on biomass integrated combined cycle systems in the 1990s. There were at least three projects undertaken in the US which had various degrees of success, though none operated in full IGCC mode (Paia, HI; Burlington, VT; Granite Falls, MN). The European Union, through the THERMIE energy program, supported

[7]http://www.ge-energy.com/products_and_services/products/gasification/syngas_turbine.jsp

commercial scale BIGCC demonstration systems. At this time, the only large scale demonstration that ran for any significant length of time was at Värnamo, Sweden between 1996 and 1999 (Williams, 2005).

2.3.2.2 Värnamo, Sweden

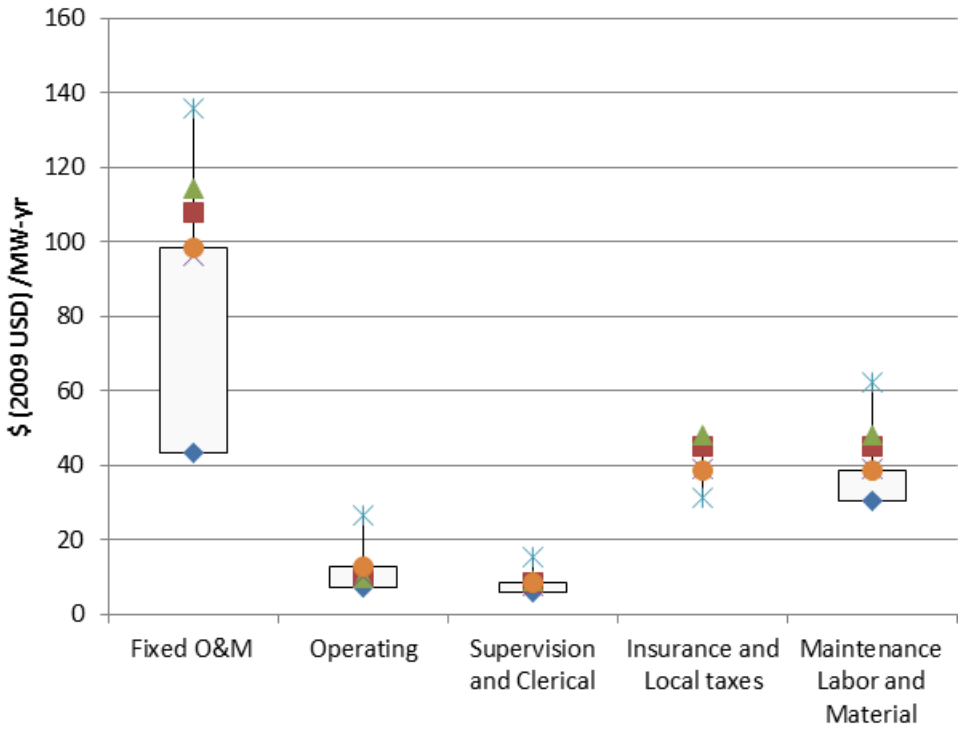
The BIGCC pilot system demonstratedat Värnamo, Sweden (Stahl et al., 2004)) was the world's first biomass-fueled IGCC plant that operated successfully for extended periods of time. This demonstration facility produced power and heat (6 MWe, 9MWth) and was developed by Sydkraft AB and Foster Wheeler International. The gasifier was a pressurized air-blown circulating fluid bed reactor that operated at pressures of 18-22 atmospheres. The facility used finely ground, dried wood and bark feedstock (10 to 20 percent moisture content) delivered to the power generation site from an adjacent preparation facility. Limited tests with pelletized straw and refuse-derived fuel (RDF) were also performed with some success (Stevens, 2001).

The gas cleaning system consisted of a cyclone separator followed by heat exchange to cool the gas to about 350ºC from ~ 900°C) thereby condensing alkali vapors on particulate matter (Stevens, 2001). The partially cooled gas was passed through a barrier filter (ceramic and/or sintered metal 'candle' filters). Tar and alkali content in the filtered gas were less than 5 $g/m^3$and 0.1 ppm (by weight) respectively (Stahl & Neergaard, 1998). The filtered gas was then fired in a gas turbine (European Gas Turbines, Ltd). The gas turbine generated about 4 MWeand the steam bottoming cycle produced 2 MWe additional (Engstrom, 1998).

The Värnamo gasification system has more operational experience than any other biomass fired gas turbine system. The gasifier was completed in 1993. In total, the gasifier operated for more than 7000 hours. The gas turbine was modified for use with low-energy gas in 1995, and test operations of the integrated biomass fueled power generation system began that year. By the end of 1999, the integrated facility had operated for a total of about 3500 hours, with most of those during 1998 and 1999. The facility was built as a near-commercial demonstration and was not intended to provide long-term power generation on a commercial basis. The demonstration of the technology was completed in 1999, and no further testing of the power generation system was planned (Stevens, 2001).

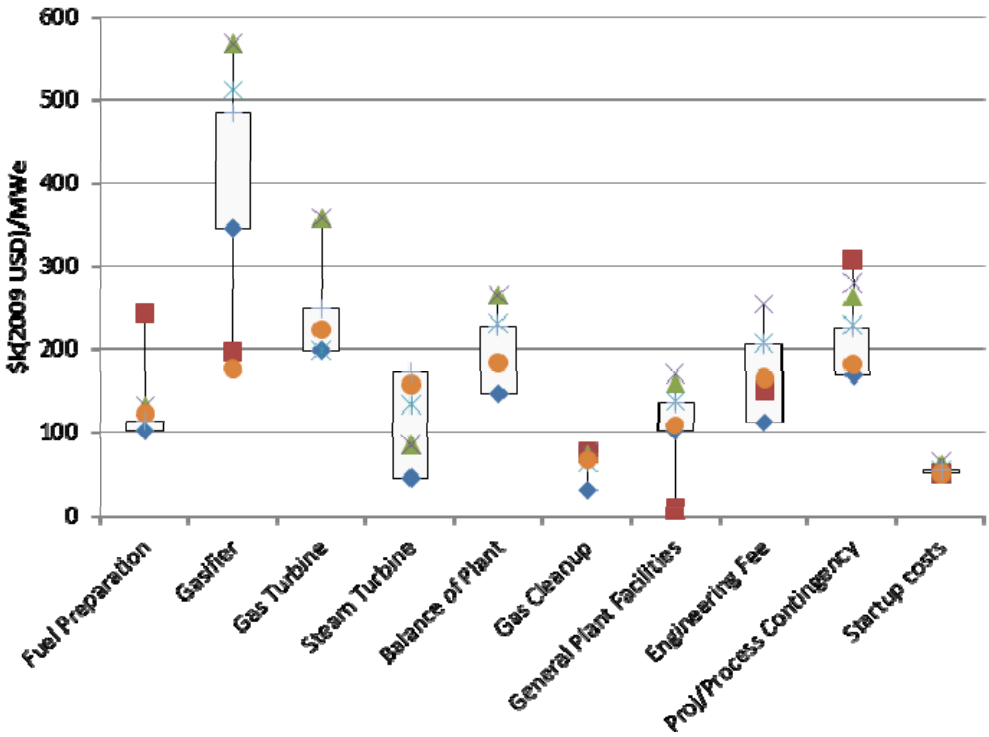
From costs reported in the literature, operations and maintenance costs (O&M) are a significant portion of the full system levelized cost of energy (COE) [Figures 8] The gasifier reactor constitutes a large share of the overall system cost [Figure 9].

Figure 8: O&M Cost Components for Gasifier Based Biomass Power Generation Facilities from Literature[8]



[8] Each symbol indicates a data point from literature. The box indicates the average values with high or low lines outside depicting outliers. Literature sources: Electric Power Research Institute, 1995; Weyerhaeuser Co, 2000; Wiltsee, 2000; Craig & Mann, 1996.

Figure 9: Gasifier System Component Costs from Literature[9]



2.3.3 Fuel Cells

Fuel cells for stationary applications have many potential advantages, but there is little data on commercial applications of fuel cells in the tens of megawatts scale. Haiming(2009) found for large biopower facilities that fuel cells were the most efficient pathway for energy generation when compared to indirectly heated BIGCC (section 2.5.2.), pressurized BIGCC, and Rankine systems. This study did not report associated costs for large capacity solid oxide fuel cells (SOFC) because they were too speculative. They concluded that the SOFC systems would be more costly than gas-turbine BIGCC systems analyzed at this large scale (more than 430 MWe).

Some pilot projects to quantify the potential have estimated a 47 percent efficiency of the system, or 73 percent in a CHP application fueled from biogas(McDannel, 2009).The project cost at the Los Angeles County Sanitation District was prohibitive for commercial applications at the time of installation ($1.9M for 250 kW, McDannel, 2007).NOx associated with the measured output of the fuel cell was 0.05ppm, less than any other of the biogas power generation options at the facility. Other emissions from the fuel cell were reported to be 1.2 ppm CO, 387 ppm CH4, and 0.30ppm TGNMO (Los Angeles County Sanitation District, 2009) – significantly lower

[9]Each symbol indicates a data point from literature. The box indicates the average values with high or low lines outside depicting outliers. Literature sources: Electric Power Research Institute, 1995; Weyerhaeuser Co, 2000; Wiltsee, 2000; Craig & Mann, 1996.

than their combustion based facilities. However, without a comparable set of data at 10-50 MWe there is not sufficient information to compare larger capacity fuel cells to more commercially available technology. (Cigolotti, 2009).

2.3.4 Pyrolysis

Pyrolysis systems are usually optimized for producing char, torrefied biomass or a liquid intermediate (bio-oil). They may be utilized in combination with combustion or gasification based systems for power generation but not likely by themselves except for the production of liquid fuels sold through commercial markets. Therefore, pyrolysis as a stand-alone option is not evaluated in this report.

2.4 Permitting

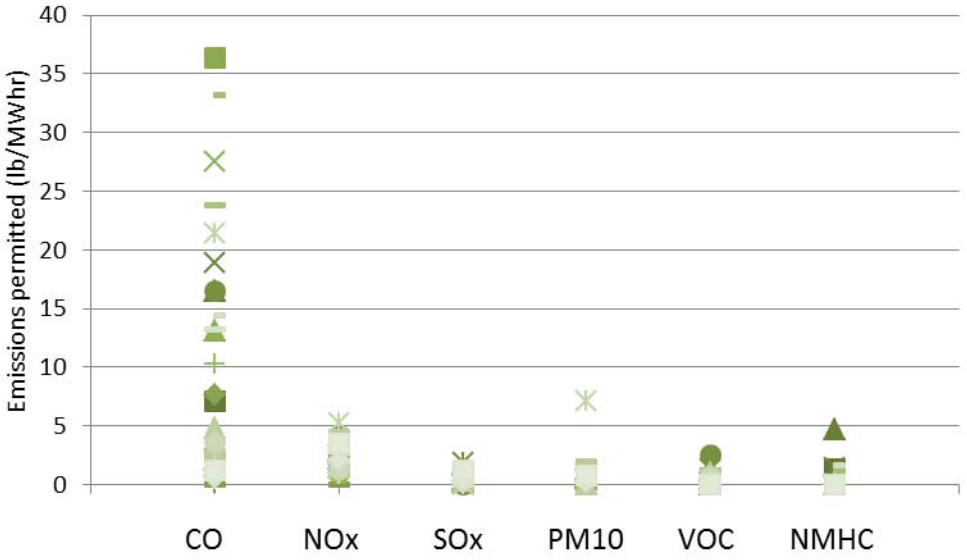
The permitting process for energy generation in California is complex and has been identified as one hurdle in establishing biomass and other energy and industrial facilities (Jenkins et al., 2006). Much of the complexity comes from air quality constraints that can be different across thirty-five separate air quality management districts, some of which are non-attainment for the National Ambient Air Quality Standards under the Federal Clean Air Act, and may require different emission controls and emission offsets. In addition to an air permit, there are also permits associated with water and solid waste discharge or disposal, land use, and building and fire safety.

The first step in the permitting process is to determine whether the facility will be a major or minor air pollution source and whether it will be built at site of an existing facility already having permits or a new unpermitted site. The permitting process for repowering in this discussion focuses on existing sites. Facilities are permitted based on local district rules and require an authority to construct, a permit to operate, and a Federal Title V air permit if a major source of air pollutants. A permit to operate must be renewed annually and typically can cost between $16,000 and $45,000 to procure.[10]

Most air permits regulate emissions of nitrogen oxides (NOx), particulate matter (PM), volatile organic compounds (VOC, or sometimes reactive organic gases, ROG or non-methane hydrocarbons, NMHC), carbon monoxide (CO), and hazardous air pollutants (HAPs) such as hydrogen chloride(HCl). Permit limits for 33 of the solid fuel biomass energy facilities in California shown as pounds of pollutant per megawatt-hour (lb/MWh) of net electricity vary widely depending on year of permitting and location (Figure 10). In many cases the operating emissions may be substantially below the permit limits, and variances are required for short term operation above the limits such as during maintenance.

[10]From Northern Sierra Air Quality Management District permits.

Figure 10: Permitted Emissions at California Solid Fuel Bioenergy Facilities[11]



Land use permitting includes siting, zoning conformance, conditional use permits, community acceptance, and the California Environmental Quality Act (CEQA). Siting, zoning, and community acceptance may be less of a concern for existing sites where a facility is already operating or has previously operated and continues to maintain permits. CEQA requires state and local agencies within California to follow a protocol of analysis and public disclosure of environmental impacts of proposed projects and adopt all feasible measures to mitigate those impacts (State of California, 2012).

[11] Each marker denotes one facility data point. Permits obtained through requests for public information from: Shasta, Tuolumne, Northern Sierra, South Coast, San Joaquin, North Coast Unified, Placer, Monterey Bay, and Yolo-Solano Air Quality Management Districts.

CHAPTER 3:
Methods of Analysis

Repowering existing biopower facilities leverages investments already made including permitting, feedstock sources, land acquisition, and equipment based on the extent to which the plant will undergo redesign.

Utilizing the same feedstock, emission levels, conversion efficiencies, and levelized cost of energy based on different technologies were evaluated. Principal revenue sources within the evaluation include:

1. Electrical energy
2. Co-products including heat, ash, char
    a. ash can be utilized for road construction or landscaping materials, as components of cement or for lightweight aggregates
3. Carbon credits or REC's
4. Tipping fees where applicable
5. Dispatchable capacity
6. Subsidies

In addition the following costs have been incorporated into the economic model:

1. Feedstock
2. Capital
3. Operation and Maintenance
4. Penalties associated with excess emissions

Constraints limiting available technology include:

1. Feedstock availability and facility scale
2. Emissions
3. Feedstock quality

The outcome of the method to evaluate the repowering potential focuses on profit as influenced by sensitivities to feedstock costs, carbon credits, electricity generation capacity, and emissions, where the profit is defined by the difference between levelized revenues and costs determined for the generation facility.

3.1 Economic Analysis

An economic model was developed to evaluate the levelized cost of energy required for repowering biopower facilities using several technology types (i.e., gasification and combustion with different prime movers and/or heat recovery). [12]

The economic model was specifically developed to evaluate the differences in the levelized cost of electricity based on differences in equipment cost, efficiencies, CHP (cogeneration) capabilities and carbon credit accounting. Additionally, it allows for different depreciation schedules including MACRS 5 year, 10 year, and 20 year, 20 year straight line depreciation. Details and description of the economic model are in the appendix.

3.2 Additional cost factors associated with bioenergy

3.2.1 Feedstock Costs

Solid fuel biomass currently used in California includes various agricultural residues (mainly orchard and vineyard prunings or whole tree removals), food processing residues (fruit and olive pits, some nut shells, rice hulls), clean urban wood and forest product residues and forest thinnings. At this time, no purpose-grown energy crops are used in California for electricity generation, although corn is used in ethanol production.
This report considers only the utilization of biomass residues and omits dedicated biomass crops from analysis.

3.2.2 Capacity Factor

Capacity factors (otherwise known as utilization rates) have a strong influence on overall cost and instant costs. The capacity factor defines the average power generated by the facility relative to its rated design power capacity, generally measured on an annual basis as the ratio of actual energy generation to the design energy generation. Capacity factors for biomass power facilities are reported to range from 19 to 106 percent, the former value quite low from a design perspective and the latter indicating an actual performance superior to the design basis. The range in capacity factor is based mainly on fuel availability and maintenance requirements, and allows for a large fluctuation in reported costs(Wiltsee, 2000).

3.2.3 Tax Credits

Certain technologies are eligible for renewable energy production tax credits and renewable energy production incentives through the Federal Energy Policy Act (EPAct) until 2013. These include a tax credit of $10.20 (2011 USD)/MWh and $21.50 (2011 USD)/MWh for open and closed loop biomass respectively. This is available to merchant vendors for a period of 10 years(Klein J. , 2009).

Conceivable economic incentives and subsidies include feed-in-tariffs, more favorable pricing under power purchase agreements (PPA), and research and development grants among other

[12] Here, repowering costs are assumed to be lower than complete new-build due to ability to continue to use some existing plant, permits, etc. The LCOE calculations are therefore incremental compared to complete LCOE for new facilities.

strategies to assist the development of the biomass industry(California Energy Commission, 2011). Feed in tariffs were recently expanded up to 20MW for individual facilities through a Renewable Auction Mechanism, beyond the 1.5MW previously allowed. The policy is an avenue for investor owned utilities (IOUs) to purchase Renewable Energy Credits from biopower producers under auction reflecting fair prices to the consumer and identifies the additional value provided by biomass facilities to provide baseload power.

3.2.4 Carbon Accounting

The concept of biomass as a carbon neutral (or even carbon net negative) feedstock has recently been debated. The carbon footprint (or degree of carbon neutrality) of biomass feedstock depends on the source of the biomass and how it was otherwise managed or used (e.g. burned or left to decompose above ground or in a landfill, or from old-growth trees or cultivated for energy purposes).Depending on assessed carbon footprint and future development of markets for carbon emissions reductions, some economic benefit could accrue to a bionenergy project.

CHAPTER 4:
Conversion Pathways

Electrical generation from solid fuel biomass feedstock at a power plant of greater than $10MW_e$ predominantly comes from two conversion technologies: direct combustion or gasification(Koppejan, 2008). In the following sections, pathways for both conversion technologies are broken into six scenarios (base case (boiler replaced with new boiler, base case + heat recovery, gasifier with single-cycle gas turbine, IGCC, integrated gasifier and fuel cell (IGFC), integrated gasifier and fuel cell combined with steam bottoming cycle (IGFCCC). The environmental and economic methods outlined in the previous sections are used to evaluate the performance of each scenario. Scenarios are compared against a reference case consisting of a conventional direct combustion-steam Rankine cycle power plant.

The main components of a biomass combustion plant are (Koppejan, 2008):

- Feedstock (fuel) storage
- Fuel feeding and handling
- Furnace
- Boiler or HRSG (combined cycle)
- Ash handling and pre treatment
- Flue gas cleaning system
- Stack
- Monitoring, control and visualization equipment
- Electric and hydraulic utilities
- Prime mover (e.g. steam turbine)

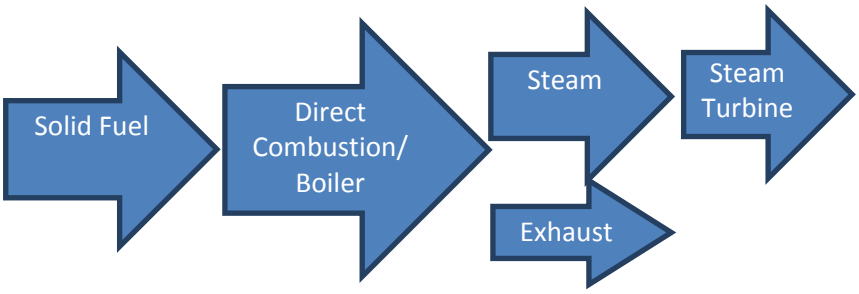
Similarly, gasification plants include:

- Feedstock (fuel) storage
- Fuel feeding and handling
- Gasifier
- HRSG (combined cycle)
- Ash handling and pre treatment
- Flue gas cleaning system
- Stack
- Control and visualization equipment
- Electric and hydraulic utilities
- Prime mover(s) (e.g. gas turbine, reciprocating engine, steam turbine)

For simplification, the following systems will be assumed to have the same feedstock, fuel storage, feeding and handling, stack, control and visualization equipment, and electric and hydraulic installations. Therefore, the evaluation of each system will be based on varying the

furnace, boiler, HRSG, ash handling and pretreatment, flue gas cleaning system (as the ash content and flue gas varies with combustion or gasification technologies), gasifier, and prime movers.

4.1 Direct Combustion with Steam Turbine (base case)



Also known as the Rankine cycle power plant, the direct combustion steam turbine process is the pathway employed for the vast majority of solid fuel biopower production in California and will therefore be considered the base or reference case for comparison. There are several small gasification-based power systems in various stages of demonstration and/or commissioning at present, but not sufficiently developed yet to serve in a reference capacity. Table 3 lists the capital cost assumptions made for the base case facility involving upgrading of the boiler and steam turbine, along with the levelized cost of energy using further assumptions as follows, which remain constant throughout the following ten scenarios: $35/BDT feedstock cost, 50 MWe nameplate capacity, 45 MWe net electrical capacity, 25 MJ/kg HHV content of feedstock, 25 percent moisture content, feedstock composition per table 3, 20 percent net efficiency (higher heating value basis), capacity factor of 90 percent,40 percent combined state and federal tax rate, 90 percent debt ratio, 5 percent interest on debt, 15 percent minimum attractive rate of return on equity (MARR), 20 year economic lifetime, and 20 year MACRS depreciation. As part of the advantage of repowering existing facilities, no new costs are assumed for interconnection with the utility.

Table 3: Capital Cost Assumptions and LCOE for Base Case Scenario (repowered by replacing boiler and other components with new, but similar equipment)

Incremental Capital Cost	**[$]**	**[$/MWe-net]**
Boiler/Combustor and Feedstock Handling System Capital Cost ($)	33,000,000	733,333
Gas Cleaning System Capital Cost ($)	20,000,000	444,444
Power Generation/Interconnect System Capital Cost ($)	7,575,000	168,333
Emission Control System Capital Cost ($)	3,650,000	81,111
Heat Recovery System Capital Cost ($)	0	0
Total Facility Capital Cost ($)	64,225,000	1,427,222

LCOE (Current,)	0.055	$/kWh
LCOE (Constant,)	0.048	$/kWh

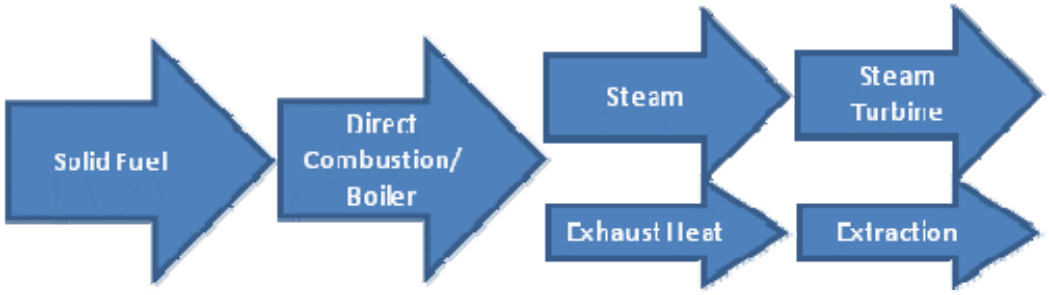
Effects of varying parameters including tax credits and depreciation schedules in constant $/kWh are shown in table 4.

Table 4: Sensitivity of Incremental LCOE for Base Case Repowering

	$/kWh
With carbon credit of $50/tC	0.049
With carbon credit of $10/tC	0.059
With REC of $21.5 per MWh	0.049
Using MACRS 5 year	0.055
Using MACRS 10 year	0.058
Using 20 year straight line	0.062
Using no depreciation	0.067

The average efficiency of a simple cycle steam turbine direct combustion system is assumed to be 20 percent[13]. Newer units tend to operate at higher efficiencies ranging up to about 27 percent. Options to increase the efficiency of the system include boiler upgrades and/or associated steam turbine upgrades, or new steam turbines. Thermal efficiencies of the Rankine cycle increase with pressure and temperature, as with advanced turbines. However, elevated pressure and temperature design conditions are associated with higher capital and maintenance costs. Upgrading steam turbines through rebuilds are rare and would involve replacing turbine blades(Sandborn, 2012). A more common method for increasing simple cycle efficiency is to add extraction capabilities for a co-generation system (section 4.2) or replacing the turbine altogether with a higher efficiency design. Turbine replacement may also require replacing the boiler to ensure high quality steam availability.

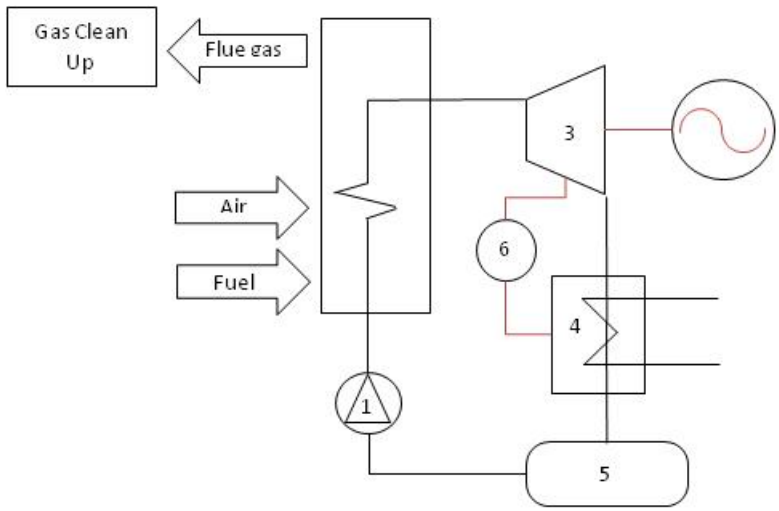
4.2 Direct Combustion with Cogeneration



[13]Jenkins, 1994; Cheng, 2010.

A simple cycle steam turbine direct combustion facility generates electricity only. In a cogeneration plant, some of the steam is extracted at an intermediate pressure and temperature for heat utilization, or heat from the process is otherwise extracted and used for other purposes. Cogeneration plants may require higher temperatures and pressures in the condenser, with a consequent reduction in the efficiency of the electricity generation while the overall system efficiency accounting for the heat utilization increases to up to 80 percent or more (Koppejan, 2008).

Figure 11: Cogeneration with Extraction of Medium Pressure Steam for Heat Utilization



1. Boiler feedwater pump
2. Boiler
3. Steam turbine (prime mover)
4. Condenser
5. Reservoir
6. Extraction of intermediate pressure steam

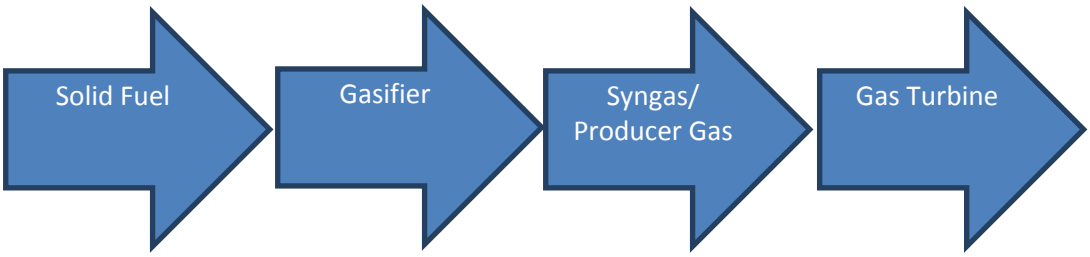
Adding the heat recovery system– in this case the extraction of intermediate pressure steam for heat recovery—to the previous simple cycle case is assumed to add $5.5 million in capital cost. With a modest heat recovery rate of 30 percent, net system efficiency increases to 43 percent (CHP) and assigning a value to heat of $10/MWh or $2.78/GJ (as an avoided cost), the levelized cost of electricity is reduced to $0.038/kWh (constant $).

Table 5: Capital Cost Assumptions and LCOE for Repowering with CHP System

Incremental Capital Cost	($)	($/MWe-net)
Boiler/Combustor and Feedstock Handling System Capital Cost ($)	33,000,000	733,333
Gas Cleaning System Capital Cost ($)	20,000,000	444,444
Power Generation ($)	7,575,000	168,333
Emission Control System Capital Cost ($)	3,650,000	81,111
Heat Recovery System Capital Cost ($)	5,500,000	122,222
Total Facility Capital Cost ($)	69,725,000	1,549,444

LCOE (Current)	0.044	$/kWh
LCOE (Constant)	0.038	$/kWh

4.3 Gasifier/Gas Turbine



Another option, though more capital intensive, is to replace the entire boiler system and steam turbine with a gasifier and gas turbine. The gasifier converts the feedstock to producer- or syngas, which is then fed to a gas turbine[14] as the prime mover. Particulate matter removal and syngas cleanup are extensive in gasifier/gas turbine systems. Using an average of capital costs from literature, the assumptions above, and the same feedstock composition, the LCOE for a gasification with simple-cycle gas turbine unit with the same nameplate capacity is $0.051/kWh. Assuming a net thermal efficiency of 21 percent (65 percent cold gas efficiency for the gasifier and 32 percent gas turbine efficiency)there is a slight feedstock reduction of 1200 kg/hr, compared to the reference case.

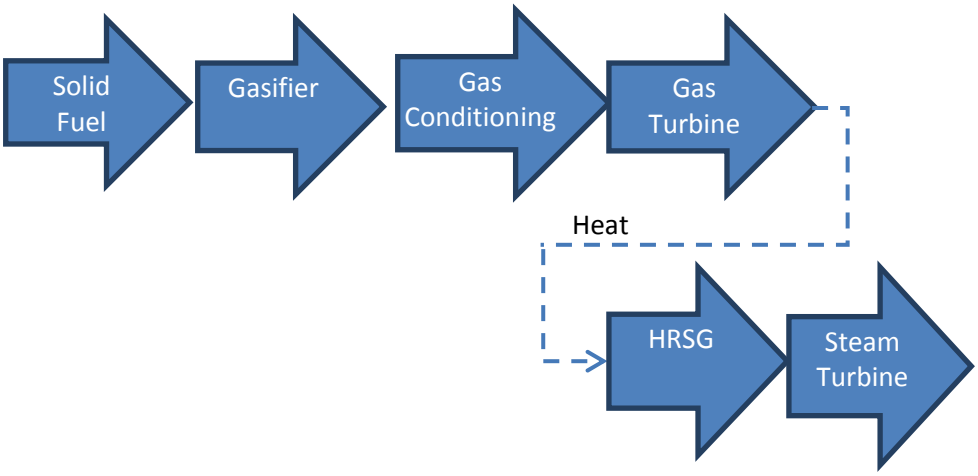
[14] http://www.ge-energy.com/products_and_services/products/gasification/syngas_turbine.jsp

Table 6: Capital Cost Assumptions and LCOE for REPOWering with Gasifier/GT System

Incremental Capital Cost	($)	($/MWe-net)
Gasifier and Feedstock Handling System Capital Cost ($)	37,525,000	833,889
Gas Cleaning System Capital Cost ($)	4,145,000	92,111
Power Generation/Interconnect System Capital Cost ($)	19,920,000	442,667
Emission Control System Capital Cost ($)	14,800,000	328,889
Heat Recovery System Capital Cost ($)	0	0
Total Facility Capital Cost ($)	76,390,000	1,697,556

LCOE (Current)	0.059	$/kWh
LCOE (Constant)	0.051	$/kWh

4.4 Integrated Gasifier Combined Cycle (IGCC with Gas Turbine)



To increase the efficiency of the gasification facility (and with further capital expense) the simple cycle gasification/gas turbine facility could have a bottoming cycle added to it – creating what is known as a combined cycle. The bottoming cycle utilizes the exhaust gas from the turbine in a heat recovery steam generator (HRSG) which can then be paired with another prime mover, typically a steam turbine. In this pathway, the superheated steam from the HRSG is fed to a steam turbine which generates additional electricity. Also known as biomass integrated gasification combined cycle or BIGCC, this advanced power generation option has only been demonstrated in Värnamo (section 2.3.2) and cost assumptions are averages from the literature. Adding the bottoming cycle decreases the LCOE to $0.041/kWh because of increased overall efficiency. Feedstock requirement is 12,400 kg/h less than the base case.

Figure 12: Schematic of Generic High Pressure Air Blown BIGCC System (USDOE 1997)

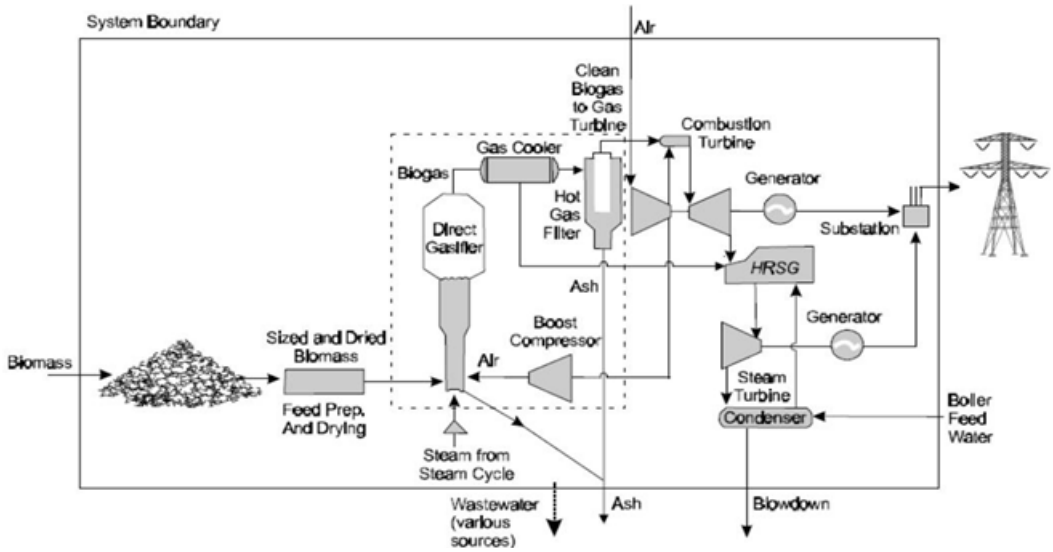
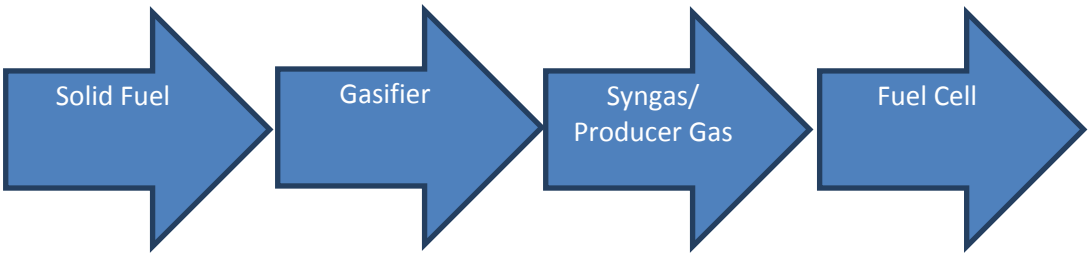


Table 7: Capital Cost Assumptions and LCOE for Repowering with IGCC System

Incremental Capital Cost	($)	($/MWe-net)
Gasifier and Feedstock Handling System Capital Cost ($)	37,525,000	833,889
Gas Cleaning System Capital Cost ($)	4,145,000	92,111
Power Generation/Interconnect System Capital Cost ($)	19,920,000	442,667
Emission Control System Capital Cost ($)	14,800,000	328,889
Heat Recovery System Capital Cost ($)	4,674,000	103,867
Total Facility Capital Cost ($)	81,064,000	1,801,422

LCOE (Current)	0.047	$/kWh
LCOE (Constant)	0.041	$/kWh

4.5 Integrated Gasifier Fuel Cell (IGFC)



One potential high efficiency pathway for solid fuel biomass is for the hydrogen rich syngas to be fed to a high temperature fuel cell (section 2.3.3). To increase the hydrogen content the amount of steam fed to the gasifier would have to be increased or further reforming of the gas would be needed.

Recently, the largest fuel cell installation was announced in South Korea and comprises four 2.8 MW DFC3000 Direct FuelCell® (DFC®) power plants for an overall capacity of 11.2 MW with a feedstock of imported natural gas. Although costs were not identified with this announcement, the system is stated to be 90 percent efficient in CHP mode and 47 percent efficient in electricity generation alone[15]. Although fed from natural gas, utility scale fuel cell systems will increase the understanding of fuel cell capabilities and associated economics for grid power as they are demonstrated. Doherty et al. (2010) modeled a solid oxide fuel cell fed by biomass syngas and found net electrical efficiency (biomass-to-electricity) of 33 percent and 74 percent for CHP. These efficiencies are lower because of energy used to produce the syngas and a lower conversion efficiency of the syngas compared to natural gas.

Costs for fuel cells from section 2.3.3 were used to estimate the cost of the fuel cell as the prime mover. Assuming emission controls and no HRSG the LCOE becomes $0.064/kWh.

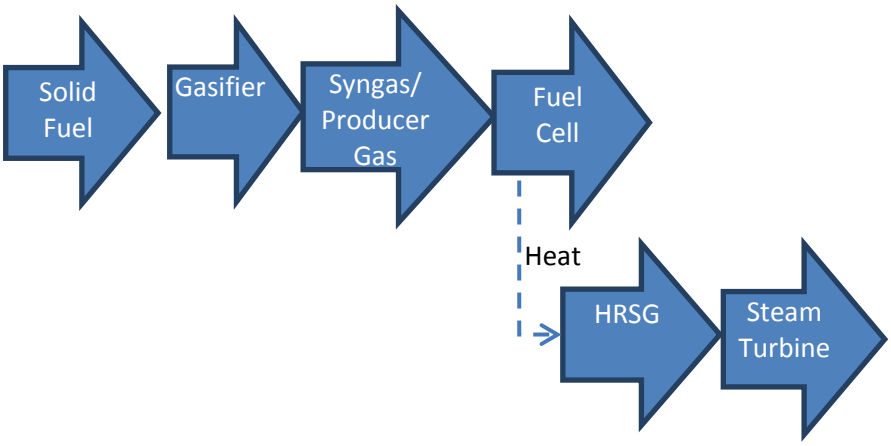
[15]http://fcel.client.shareholder.com/releasedetail.cfm?ReleaseID=623842

Table 8: Capital Cost Assumptions and LCOE for Repowering with IGFC system

Incremental Capital Cost	($)	($/MWe-net)
Gasifier and Feedstock Handling System Capital Cost ($)	37,525,000	833,889
Gas Cleaning System Capital Cost ($)	18,945,000	421,000
Power Generation/Interconnect System Capital Cost ($)	80,000,000	1,777,778
Emission Control System Capital Cost ($)	0	0
Heat Recovery System Capital Cost ($)	0	0
Total Facility Capital Cost ($)	136,470,000	3,032,667

LCOE (Current)	0.074	$/kWh
LCOE (Constant)	0.064	$/kWh

4.6 Gasifier/fuel cell/CC



Adding a bottoming cycle to the gasifier/fuel cell pathway has never been demonstrated; however, besides electricity and excess hydrogen, a product of the electrochemical process within the fuel cell is heat, especially if using a solid oxide fuel cell. The heat could be used to generate steam to turn a steam turbine or with an ORC at lower exhaust temperatures.

Although CHP efficiencies of fuel cell systems approach 90 percent (section 4.5), the CHP efficiency of the biomass gasifier to fuel cell/combined cycle system is assumed to be 52 percent (33 percent electricity with 19 percent additional from heat) resulting in a LCOE decreased slightly from $0.064/kWh to $0.060/kWh from the previous case. This can be attributed to the high capital cost of the fuel cell serving as the primary factor in the economics of the system with the addition of a heat recovery system contributing a relatively small amount of the overall capital cost.

Table 9: Capital Cost Assumptions and LCOE for Repowering with IGFCCC system

Incremental Capital Cost	($)	($/MWe-net)
Gasifier and Feedstock Handling System Capital Cost ($)	37,525,000	833,889
Gas Cleaning System Capital Cost ($)	18,945,000	421,000
Power Generation/Interconnect System Capital Cost ($)	80,000,000	1,777,778
Emission Control System Capital Cost ($)	0	0
Heat Recovery System Capital Cost ($)	4,674,000	103,867
Total Facility Capital Cost ($)	141,144,000	3,136,533

LCOE (Current)	0.069	$/kWh
LCOE (Constant)	0.060	$/kWh

4.7 Cost Summary

The capital cost assumptions for each scenario and the estimated LCOE results are summarized in Table 10. The scenario with the lowest capital cost (base case at $1427/kW) has a midrange electricity generation cost (LCOE, Constant $0.048/kWh). The lowest LCOE is the base case with CHP at $0.038/kWh where heat sales more than compensate for the additional capital cost of the CHP equipment.

Table 10: Summary of Capital Cost and LCOE for repowering Scenarios

	Capital Cost, Installed ($/kW net)	LCOE (Current, $/kWh)	LCOE (Constant, $/kWh)
Base Case	1427	0.055	0.048
Base Case + CHP	1549	0.044	0.038
Gasifier w/ GT	1698	0.059	0.051
BIGCC	1801	0.047	0.041
IGFC	3033	0.074	0.064
IGFCCC	3137	0.069	0.060

The highest LCOE scenarios are those associated with gasifier-to-fuel cells ($0.64 and $0.60/kWh) where capital cost increment is more than the associated efficiency improvement. These results are preliminary pending scrutiny of the literature and capital cost assumptions for the scenarios. For instance, conservative assumptions on system efficiencies (both for electricity and CHP) for the combustion pathways were used. Assessing the sensitivity of costs to efficiencies in the combustion scenarios as well as the others may change the rank ordering of these scenarios, at least by the criterion of LCOE. A quantitative discussion of emissions for

each scenario (and comparisons to business as usual – not repowering) would help inform scenario outcomes and offer insight for potential health and air-shed improvements. For scenarios with emissions reductions, the economic potential from selling emissions reductions on offset markets needs analyzing for impacts on LCOE.

CHAPTER 5: Conclusions

The analysis of repowering scenarios outlined here suggests economic opportunities exist for the biomass power industry in addressing refurbishment or replacement needs for generating equipment or for installing new systems. However, a number of uncertainties surround this issue, especially as large scale demonstrations are mostly lacking of alternative and potentially higher efficiency power systems and specific performance and cost information are still to be developed. Implementing CHP where possible in facilities currently generating electricity only has some clear advantages in levelized cost of electricity (LCOE) if heat is consistently valued with that from purchased natural gas. Integrated gasification combined cycles (IGCC) may also realize cost advantages in comparison with Rankine cycle combustion power plants, but the difference in estimated LCOE ($0.041 vs. 0.048/kWh) is in a range where substantial new information on commercial scale cost and performance is required to gain substantial confidence in the potential benefits associated with this type of repowering. Integrated fuel cell systems may also offer substantial efficiency advantages, but estimated capital costs result in LCOE above both the reference Rankine cycle and IGCC systems. Reductions in emissions would also allow for capacity expansions at existing sites, and related investigation constitutes a further element of continued research needed to more fully assess individual site as well as industry-wide potentials for economic and other performance benefits that might accrue through repowering.

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APPENDIX A

All shaded boxes can be changed to alter the outcome and compare sensitivities.

Table A-1: Model shown for the Generic Gasifier

Capital Cost	($)	($/MWe-net)
Gasifier and Feedstock Handling System Capital Cost ($)	33,000,000	733,333
Gas Cleaning System Capital Cost ($)	20,000,000	444,444
Power Generation/Interconnect System Capital Cost ($)	9,000,000	200,000
Emission Control System Capital Cost ($)	32,000,000	3,555,556
Heat Recovery System Capital Cost ($)	6,000,000	133,333
Total Facility Capital Cost ($)	100,000,000	2,222,222

Total Facility =∑Gasifier(or boiler):HRSG Capitol Cost

Table A-2: Electrical and Fuel

Electrical and Fuel--base year	
Gross Electrical Capacity (MWe)	50
Net Electrical Capacity (MWe)	45
Efficiency (%)	**90**
Capacity Factor (%)	90
Annual Hours	7,884
Annual Net Electricity Generation (MWh)	354,780
HHV Efficiency of Gasification/Combustion System--Biomass to Clean Gas (%)	65.0
Net HHV Efficiency of Power Generation (%)	40.0
Overall Net System Efficiency (%)	26.0
Clean Gas Composition (% by volume, dry) - from emissions model	
CO	24.2
H_2	28.0
Hydrocarbons (as CH_4)	0.0
CO_2	5.4
O_2	0.0
N_2	38.2
Clean Gas Molecular Mass (kg/kmol)	19.77
Clean Gas Density 298K, 1 atm (kg/Nm^3)	0.809
Clean Gas Higher Heating Value (MJ/kg)	42
Clean Gas Lower Heating Value (MJ/kg)	36
Total Fuel Power Input (MW)	113
Gas Flow Rate (kg/h)	9,596
Annual Clean Gas Consumption (kg/y)	75,656,451
HHV of Biomass Feedstock (MJ/kg)	25
Moisture Content of Biomass Feedstock (% wet basis)	15.0
Biomass Feed Rate (kg/h)--dry basis	24,923
Annual Biomass Consumption (kg/y)--dry basis	196,493,538
Annual Biomass Consumption (kg/y)--wet basis	231,168,869
Ash Content of Biomass (% dry matter)	5
Carbon Concentration of Char (% dry basis)	30
Char Production Rate (kg/h)--dry	1,780

Annual Char Production (kg/y)--dry	14,035

Given:

Table A-3

Mc	12.01115	[kg/mole]
MH	1.00797	
MS	32.064	
MO2	31.9988	
MCO	28.01055	
MCO2	44.00995	
MH2O	18.01534	
MH2	2.01594	
MSO2	64.0628	
MN2	28.0134	
	HHV [MJ/kg]	LHV [MJ/kg]
CO	10.1	10.1
H2	142	120
CH4	55.5	50

Efficiency = $\frac{GrossElectricalCapacity}{NetElectricalCapacity}$

Annual Hours = $\frac{CapacityFactor}{100}$ x 8760

Annual Net Electricity Generation = Annual Hours x Net Electrical Capacity

Overall Net System Efficiency = $\frac{HHVEfficiencyofbiomasstocleangasxNetHHVEfficiencyofPowerGeneration}{100}$

Clean Gas Molecular Mass = $\frac{(COxMCO)+(H2xMH2)+(CH4xMCH4)+(O2xMO2)+(N2xMN2)}{100}$

Where

CO, H_2, SO_2, Hydrocarbons (as CH_4), CO_2, O_2, and N_2 are the clean gas composition as a percentage by mass, dry, from the emissions model in section 3.1.

Clean Gas Density at 298K, 1atm (conversion factors) = Clean Gas Molecular Mass x $\frac{298 x 1.01325}{8314}$

Clean gas higher heating value = $\sum X_i \times HHV_i$ for the clean gas composition

HHV_i = higher heating value for each component of the clean gas composition

Clean gas lower heating value = $\sum X_i \times LHV_i$ for the clean gas composition

LHV_i = lower heating value for each component of the clean gas composition

Total fuel power input = $\frac{NetHHVsystemefficiency}{Netelectricalcapacity/100}$

Gas flow rate = $\frac{Totalfuelpowerinpux\ 3600}{Cleangashigherheatingvalue}$

And

Annual clean gas composition = gas flow rate x annual hours

Additionally, to calculate the tones of tCO2e/yr

$$=\left[\left(\frac{Cleangasmolecularmass}{MCO_2}\right)\times\left(\frac{CO_2(fromemissionsmodel)}{100}\right)\times gasflowrate\right]\times annualhours\times 0.001$$

Biomass feed rate = $\frac{totalfuelpoweroutput}{HHVefficiencyofgasification/100}\times HHVofbiomassfeedstock\times 3600$

Annual biomass consumption (dry basis) = biomass feed rate x annual hours

Annual biomass consumption (wet basis) = $\frac{annualbiomassconsumption\ (drybasis)}{1-moisturecontentofbiomassfeedstock}$x 100

Char production rate =$\frac{ashcontentofbiomass}{100}\times\left(\frac{biomassfeedrate}{1-carboncontentratioofchar/100}\right)$

Annual char production = char production rate x $\frac{annualhours}{1000}$

Next, if dealing with co-generation, the heat rate is calculated

Table A-4

Heat--base year	
Total heat production rate (MWth)	63
Aggregate fraction of heat recovered (%)	20
Recovered heat (MWth)	13
Annual heat sales (MWhth/y)	98,550
Aggregate sales price for heat ($/MWh)	10.0000
Total income from heat sales ($/y)	985,500
Heat income per unit net electrical energy ($/MWh-net)	2.7778
Overall CHP Efficiency--Gross (%)	55.6
Overall CHP Efficiency--Net (%)	51.1

Where

Total heat production rate = total fuel power input - gross electrical capacity

Recovered heat = $\frac{totalheatproductionratexaggregatefractionofheatrecovered}{100}$

Annual heat (sales) = recovered heat x annual hours

And

Total income for heat sales (or heat charges avoided) = annual heat sales x aggregate sales price for heat

Heat income per unit net electrical energy = $\frac{totalincomeforheatsales}{annualnetelectricitygeneration}$

Overall CHP efficiency (gross) = $\frac{grosselectricalcapacity \times annualhours + annualheatsales}{totalfuelpowerinput \times annualhours} \times 100$

Overall CHP efficiency (net) = $\frac{annualnetelectricitygenerations + annualheatsales}{totalfuelpowerinput \times annualhours} \times 100$

Taking the given capital cost above the expenses are calculated as

Table A-5: Title Needed

Expenses--base year	
Delivered feedstock cost ($/kg)	0.04
Annual feedstock cost ($)	6,877,274
Operating expenses rate (% of capital investment)	4
Operating expenses ($)	4,000,000
Total annual expenses including feedstock	10,877,274

Where delivered feedstock cost is calculated as

Feedstock cost ($/kg) = $\frac{feedstockcostperBDT}{0.001}$

Annual feedstock cost = feedstock cost x annual biomass consumption (dry basis)

Operating expenses = $\frac{totalfacilitycost \times operatingexpensesrate}{100}$

Total annual expenses =annual feedstock cost + operating expenses

Table A-6: Title Needed

Other Revenues or Cost Savings	($/year)
Electrical energy	0
Incentive payments	0
Capacity	0
Total income for heat sales [$/yr]	985,500
Char cost [$/kg]	5
Residues	70,176
Total	1,055,676

Residues = Char cost x annual char production

Total = $\sum Electricalenergy: Residues$

Table A-7

Taxes and Tax credit	
Federal Tax Rate (%)	34.00
State Tax Rate (%)	9.30
Production Tax Credit ($/MWe)	0.000
Carbon Reduction Credit ($)	743621.966
Negative taxes allowed to offset taxes elsewhere? (Yes or No)	Yes
Combined Tax Rate (%)	40.14

Table A-8

Carbon credit	
5	$/tCO2e
148,724	tCO2e/yr

Carbon credit = $/tCO2e x tCO2e/yr

Combined tax rate =State tax rate + Federal tax rate x $\frac{(1-statetaxrate)}{100}$

Assume escalation on all payments/credit/sales as 2.10 %/yr

Table A-9

Financing	Value
Debt ratio (%)	90.00
Interest rate on debt (IRD) (%/y)	5.00
One year debt reserve required? (Yes or No)	Yes
Minimum attractive rate of return on equity (MARR) (%/year)	15
Economic Life (y)	20
Amount of capital financing ($)	100,000,000
Equity ratio (%)	10.00
Weighted Cost of Money (Current, %)	6.00
Weighted Capital Recovery Factor (Current, Overall)	0.0872
Real Cost of Money (Constant, %)	3.82
Weighted Capital Recovery Factor (Constant, Overall)	0.0724
Debt recovery:	
Total debt principal ($)	90,000,000
Capital Recovery Factor (Debt)	0.0802
Annual debt repayment ($/year)	7,221,833
Total debt repayment (principal plus interest) ($)	144,436,657
Equity recovery:	
Total Equity Principal ($)	10,000,000
Capital Recovery Factor (equity MARR)	0.1598
Annual equity repayment at MARR ($/year)	1,597,615
Total equity repayment (principal plus interest) ($)	31,952,294
Real Cost of Equity (Constant, %)	12.63
Capital Recovery Factor (equity, Constant)	0.1392
Total Debt + Equity Recovery:	
Annual total capital recovery ($/year)	8,819,448
Total capital recovery ($)	176,388,951

Where:

Equity ratio = 100 – debt ratio

Weighted cost of money (WCM) = $\frac{Debtratio}{100} \times Interestrateondebt + \frac{equityratio}{100} \times MARR$

Weighted capital recovery = $\frac{\frac{WCM}{100} \times \left[\frac{(1+WCM)}{100}\right]^{economiclife}}{\left(1+\frac{WCM}{100}\right)^{economiclife} - 1}$

Note: economic life must be 30 years or less

Real cost of money (RCM) = $\frac{1+\frac{WCM}{100}}{\left(1+\frac{Generalinflation}{100}\right)} - 1 \times 100$

Weighted capital recovery factor $\frac{\frac{RCM}{100} \times \left[\frac{(1+RCM)}{100}\right]^{economiclife}}{\left(1+\frac{RCM}{100}\right)^{economiclife} - 1}$

Total debt principle = amount of capital financed x $\frac{debtratio}{100}$

Capital recovery factor (debt) = $\frac{\frac{IRD}{100} \times \left(1+\frac{IRD}{100}\right)^{economic\,life}}{\left(1+\frac{IRD}{100}\right)^{economic\,life}-1}$

Annual debt repayment = total debt principal x capital recovery factor

Total debt repayment = annual debt repayment x economic life

Total equity principal = $\frac{amount\,of\,capital\,financing \times equity\,ratio}{100}$

Capital recovery factor (equity) = $\frac{\frac{MARR}{100} \times \left(1+\frac{MARR}{100}\right)^{economic\,life}}{\left(1+\frac{MARR}{100}\right)^{economic\,life}-1}$ 1

Annual equity repayment = total equity principal x capital recovery factor (equity)

Total equity repayment = annual equity repayment x economic lifetime

Real cost of equity (RCE) = $\left[\frac{1+\frac{MARR}{100}}{1+\frac{inflation\,rate}{100}}-1\right] \times 100$

Capital recovery factor (equity, constant) = $\frac{\frac{RCE}{100} \times \left[\frac{(1+RCE)}{100}\right]^{economic\,life}}{\left(1+\frac{RCE}{100}\right)^{economic\,life}-1}$

Annual total capital recover = annual debt repayment + annual equity repayment

Total capital recovery = total debt repayment + total equity repayment

The depreciation can be chosen from the options listed above and affects the taxes in the annual cash flow calculations shown in Appendix 1.

The levelized energy revenue requirements are calculated as total present worth x MARR. The levelized cost of energy is then the revenue requirements divided by the annual net electricity generation and can be in current or constant dollars.

Depreciation Schedule of Economic Model

The following shows the depreciation schedules for the five options. This particular model run uses the 50 MWe(45 MWe net) plant with a 20 year lifetime referenced in section 3.2, and the MACRS 20 year depreciation schedule.

Table A-10

[redacted]

[redacted]

Table A-11a: Annual Cash Flow

[redacted]

Table A-11b: cont.Annual Cash Flow

[redacted]