CALIFORNIA ENERGY COMMISSION

Energy Research and Development Division

FINAL PROJECT REPORT

Paths to Sustainable Distributed Generation through 2050

Matching Local Waste Biomass Resources with Grid, Industrial, and Community Needs

Gavin Newsom, Governor

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PREFACE

The California Energy Commission's (CEC) Energy Research and Development Division supports energy research and development programs to spur innovation in energy efficiency, renewable energy and advanced clean generation, energy-related environmental protection, energy transmission and distribution and transportation.

In 2012, the Electric Program Investment Charge (EPIC) was established by the California Public Utilities Commission to fund public investments in research to create and advance new energy solutions, foster regional innovation and bring ideas from the lab to the marketplace. The CEC and the state's three largest investor-owned utilities—Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company—were selected to administer the EPIC funds and advance novel technologies, tools, and strategies that provide benefits to their electric ratepayers.

The CEC is committed to ensuring public participation in its research and development programs that promote greater reliability, lower costs, and increase safety for the California electric ratepayer and include:

- Providing societal benefits.
- Reducing greenhouse gas emission in the electricity sector at the lowest possible cost.
- Supporting California's loading order to meet energy needs first with energy efficiency and demand response, next with renewable energy (distributed generation and utility scale), and finally with clean, conventional electricity supply.
- Supporting low-emission vehicles and transportation.
- Providing economic development.
- Using ratepayer funds efficiently.

Paths to Sustainable Distributed Generation Through 2050: Matching Local Waste Biomass Resources With Grid, Industrial, and Community Needs is the final report for the Advancing Cleaner, Less Costly, More Reliable Distributed Generation to Enable Customer Solutions and Zero-Net Energy Communities project (Contract Number EPC-14-030) conducted by Lawrence Berkeley National Laboratory. The information from this project contributes to Energy Research and Development Division's EPIC Program.

For more information about the Energy Research and Development Division, please visit the CEC's research website (www.energy.ca.gov/research/) or contact the CEC at 916-327-1551.

ABSTRACT

This project identifies and evaluates current and future organic waste fuel types and matches these wastes with local grid, industrial, building power, and thermal energy needs. The team developed data on organic waste streams and thermal energy needs, and then constructed a techno-economic analysis model that can process the data and compute viable production of electricity, waste heat, biogas, and/or biomethane for a range of energy price points. Scenarios generated by the model include allocation of local organic waste streams to existing or new conversion infrastructure and are evaluated in a lifecycle assessment model to determine local and global environmental impacts. The project's web-based tool provides rapid evaluation of potential waste-to-energy sites, including retrofits and expansions of existing facilities or entirely new construction, on the basis of resource availability, potential for waste heat use, and economic and environmental metrics.

Keywords: biomass, biogas, biomethane, anaerobic digestion, gasification, distributed generation, district energy systems, agriculture, municipal solid waste, food waste

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Introduction

Significant changes to California's electricity sector are required to meet the state's Renewables Portfolio Standard (RPS) goal of 60 percent renewable electricity supply by 2030 and net carbon neutrality goal by 2045. These targets must be met in a way that ensures clean energy equity and a fair distribution of benefits achieved by clean energy policy. Renewable distributed generation, defined here as power plants with capacity at or below 20 megawatts (MW), is expected to play an important role in these pathways. Distributed generation can provide an array of benefits to ratepayers, including reduced transmission losses, improved grid reliability and resiliency, reduced need for transmission and distribution investments, and the opportunity to meet building and industrial power and thermal energy demand with renewable energy. Through detailed, rigorous analysis, this project provides the information needed to divert the state's non-forestry organic wastes from high-emission fates, such as landfills and open burning, to distributed generation. The project matches non-forest derived local organic waste fuel sources in California with local demand for distributed generation and waste heat applications to identify opportunities for efficient, cost-effective, and environmentally sustainable distributed biopower and waste-to-energy projects. Strategies to improve the economics of waste-to-energy distributed generation systems are critical for achieving California's goals for clean energy, waste diversion, and greenhouse gas emission reductions.

Project Purpose

According to the U.S. Department of Energy's *U.S. Billion-Ton Update*, California currently has the potential to produce nearly 10 million dry tons annually of sustainable, secondary biomass at under $50/ton. The state's waste biomass, which is often limited in its usefulness by the expense of collection and long-distance transportation to centralized processing and combustion facilities, can be an ideal match for smaller decentralized electricity generation of 20 megawatts or fewer. However, there is a disconnect between studies that develop waste biomass use strategies and studies focused on identifying opportunities for distributed generation, specifically for combined heat and power and for combined cooling, heat and power.

The research team developed scenarios through 2050 that identified the most promising opportunities for waste biomass-fired distributed generation, identified key technical and regulatory hurdles to waste biomass distributed generation, developed tools for matching available non-forestry waste biomass resources with energy production and supply opportunities, and suggested solutions for achieving cost parity with fossil fuels.

Project Process

The project used a unique combination of resource assessment and needs assessment to highlight "low-hanging fruit" distributed generation projects and approaches that would not otherwise be obvious. The analysis is divided into four major tasks: the waste biomass supply assessment; the distributed generation and thermal energy demand assessment; the densification of biomass (for example, pelletizing), logistics, and power generation review; and the cost and environmental assessment.

For the waste biomass supply assessment, an extensive review of organic waste production and time variation was conducted across agriculture, processors, and municipal sources. Existing waste biomass inventories and trends in waste generation were combined with newly collected data to provide a sub-annual (monthly) and sub-county (fine-resolution, varying by biomass type) inventory for 2014, 2020, and 2050.

For the distributed generation and thermal energy demand assessment, current and potential future building thermal energy needs were characterized and mapped by developing a building stock turnover model that used tax assessor parcel data for the state to estimate possible changes in total floorspace and energy end use intensities at the land-parcel level. Although there were numerous statewide analyses of heating and cooling consumption and demand in California, outputs from past analyses are not readily downscaled to smaller building resolutions. Outputs of the building stock turnover model supported identifying locations with heat energy consumption densities that could potentially warrant the construction or expansion of hot water and chilled water district energy system networks.

For the densification, logistics, and power generation review, the team reviewed existing and emerging waste organic processing, transportation, and conversion technologies to further understand the potential for single-type and mixed-type organic waste feedstock use and conversion by 2050.

For the cost and environmental assessment, the researchers developed a conversion facility sizing and siting tool as well as a coupled techno-economic analysis and lifecycle assessment framework to match the most promising technologies and technically available waste organic feedstocks at specific energy price points. The conversion facility cost model conducted a statewide analysis using a site-level cost and optimization model. For a given site, the model assessed the available feedstocks within a defined maximum distance and calculates the expected costs and revenues of building different types of facilities at different scales at the site. The model then chose the most profitable facility at that given site, compared it to all other sites in the model, and "built" the facility, removing its accepted feedstocks from the analysis. The process was repeated with the remaining feedstocks to determine the next facility built. Once no profitable facilities were possible, the model aggregated the total amount of biogas or biomethane produced, the total waste processed, and the types and sizes of facilities built. The team conducted analyses for different energy types (biogas, biomethane, or syngas) at various price levels. The result was a supply curve of energy products in the state, and data such as waste diversion and ideal facility types and locations, which were fed into a lifecycle assessment to quantify impacts such as net changes in greenhouse gas emissions.

While the waste conversion model quantified the amount of biomethane, biogas, and syngas that is economically feasible at various price points, the district energy cost model assessed the economics of district energy networks and associated energy generation and supply assets utilizing these energy products to generate and sell energy as electricity, heat, and cooling.

Additionally, the researchers constructed a web-based siting tool (biositing.jbei.org/California) to allow users to identify available waste organics and waste organic conversion infrastructure within a set distance of a given latitude and longitude in California.

The project team invited experts and stakeholders in different sectors to participate in this process as part of a technical advisory committee. The committee was split into two working groups, one focused on biomass availability and one on distributed generation/district energy systems. Later, the two groups were combined to offer feedback on the entire project when the two parallel analyses were combined. These committee members provided feedback and facilitated contact with additional stakeholders and experts.

Project Results

This project successfully developed and demonstrated a number of innovative modeling capabilities, including: (1) a building stock turnover model for projecting changes in building floorspace and thermal energy end use at the Tax Assessor land-parcel level; (2) a web-based biositing tool for evaluating the waste biomass resource and energy generation infrastructure at any location in California; (3) a waste conversion facility siting model for locating and sizing wet anaerobic digestion, dry anaerobic digestion, dairy digesters, and gasification waste-to-energy projects for a given energy price point; and (4) a coupled techno-economic and lifecycle analysis framework for evaluating economic and environmental impacts of different pathways that can process large datasets on highly heterogeneous waste organics and perform Monte-Carlo Simulations (stochastic simulations to capture the propagation of uncertainty in complex analyses).

The researchers quantified biomass residues from agriculture, industrial, and municipal sectors and categorized them into wastes suitable for gasification, dry anaerobic digestion, wet anaerobic digestion, or dairy manure anaerobic digestion. The 125 residue types included in the project analysis provided unique insights into the attractiveness and cost-effectiveness of processing available local biomass residue types. For example, orchard and vineyard residues are more valuable than crop residues, due to the higher estimated syngas yield, while field residues proved preferable to crop residues because of their much lower moisture content.

The web-based biositing tool developed by the project team (biositing.jbei.org/California) allows for rapid evaluation of potential waste-to-energy sites, including retrofits and expansions of existing facilities or entirely new construction, on the basis of resource availability and potential for waste heat use. Stakeholder feedback on the functionality of the tool was positive, indicating that the abilities to assess resources and filter feedstocks based on the desired facility type could help in assessing the viability of different locations. However, the team also received feedback that policy incentives are often a driving factor in selecting different sites, so future iterations should include various economic incentives that could make one location more attractive than another (for example, Opportunity Zones).

The researchers estimated the “break-even” point for cost per unit of supplied thermal energy for a district energy network option compared with assumed default building thermal energy sources for different regions in California. These costs inform the potential offset of fossil energy sources possible with the provision of thermal energy from biomass-fueled distributed generation and allow for the screening of locations based on thermal energy consumption densities. The team found that expansion of existing district energy systems is generally too costly or otherwise infeasible. New construction is likely to be most attractive for district energy systems that use organic waste. Of all the scenarios evaluated, district energy networks integrated into new construction using biomass gasification and fuel cell power generation proved most economical, and this was the only scenario that resulted in a positive net present value ($10 million), meaning the energy revenues assumed were higher than the costs of supplying energy to the buildings in the development site. Comparable projects using spark ignited engines were considerably less attractive (new present value of -$26 million or less). This reflects the fact that implementation costs for new systems are likely to be considerably cheaper than for retrofits, as installing systems in locations with little to no existing infrastructure does not present the same risks or obstacles as installing new pipe infrastructure in busy streets. The building stock turnover model developed in this project provided insight into which areas in California are expected to build substantial new construction.

The researchers computed environmental costs and benefits of potential waste-to-energy projects by performing an analysis of the energy and material inputs required to convert organic wastes to valuable forms of energy and to deliver that energy to end uses. Landfill emissions are the largest driver of greenhouse gas emissions, and strategies that reduce landfilling of organics generally achieve substantial emission reductions. Open burning of agricultural waste is the second largest emissions contributor in the scenarios evaluated in this report. In the Business as Usual scenario, management of non-forestry organic waste in California emits approximately 120 kilograms (kg) carbon dioxide equivalent (CO_2eq) per tonne (metric ton) of waste. Assigning a high value to biobased electricity generation can achieve net average system-wide emissions of -20 kg CO_2eq per tonne by 2050. Agricultural waste burning is the dominant contributor for other pollutants of interest, such as particulate matter and nitrogen oxides (NO_x), and avoiding this open burning is essential to reducing system-wide emissions.

The project's waste conversion facility siting model quantified the amount of biomethane, biogas, and syngas that is economically feasible at various price points, and feeds into a district energy cost model to assess the economics of district energy networks, and associated energy generation and supply assets using these energy products, to generate and sell energy in the form of electricity, heat, and cooling. The researchers identified feedstocks that are economically attractive for bioenergy with or without the additional revenue generated from a landfill tipping fee. The tools developed in this project are capable of quantifying biopower, biogas, and biomethane generation for a broad range of waste-to-energy deployment scenarios at the state and local scales. The results indicate that biogas generation from wet wastes increases dramatically as prices rise from $12 per thousand cubic feet (Mcf) of methane to $24 per Mcf, then rise more incrementally as the methane price reaches $36, $48, and $60 per Mcf. For syngas, the amount of low moisture waste attractive to gasify increases most dramatically in the transition from $45 per megawatt-hour of gas content to $72; further increases gain very little additional biomass utilization.

Specific advancements during this agreement include successfully developing and demonstrating a number of innovative modeling capabilities, including: (1) a building stock turnover model for projecting changes in building floorspace and thermal energy end use at the Tax Assessor land-parcel level; (2) a web-based biositing tool for evaluating the waste biomass resource and energy generation infrastructure at any location in California; (3) a waste conversion facility siting model for locating and sizing wet anaerobic digestion, dry anaerobic digestion, dairy digesters, and gasification waste-to-energy projects for a given energy price point; and (4) a coupled techno-economic and lifecycle analysis framework for evaluating economic and environmental impacts of waste-to-energy pathways that can process large datasets for different waste organics. To demonstrate the framework and analytical capabilities developed in this project, the team also conducted a case study for PepsiCo to evaluate the cost and environmental tradeoffs of on-site treatment for beverage manufacturing waste streams. The results indicate that on-site treatment with anaerobic digestion and energy generation offers clear greenhouse gas benefits in the case of a concentrated sugar stream.

Technology/Knowledge Transfer/Market Adoption

Over the course of this project, the team disseminated knowledge gained in this project to a wide range of stakeholders, including regulatory bodies in California such as CalRecycle and the California Air Resources Board, private companies, and experts outside of the state. The team also presented at the California Bioresources Economy Summit in 2019 and presented results to key experts at the California Energy Commission, California Air Resources Board, CalRecycle, the U.S. Environmental Protection Agency, and the Bioenergy Association of California. Additionally, the team demonstrated the biositing tool for groups spanning venture capitalists to industry stakeholders to researchers. Feedback on the interface and content proved valuable and allowed the team to further refine its functionality. The team also regularly presented to and received feedback from the technical advisory committee, which included the experts recognized in the acknowledgements section of this report.

Benefits to California

The project provides a new analytical framework to evaluate biomass distributed generation projects and reveals the market conditions necessary to divert organic waste from high-emission end uses such as open burning and landfilling. If policy-makers choose to incentivize the generation of renewable energy from organic waste at levels sufficient to catalyze new investment (as discussed above), the results of this project could spur the diversion of nearly 10 million tonnes of wet waste and 12 million tonnes of low moisture waste annually to higher-value applications. This framework can analyze the variations in benefits for locally-tailored distributed generation systems, waste biomass resources, and local demand for heat, cooling, and power. The tools developed in this analysis to evaluate the cost and environmental impacts of a potential waste-to-energy project can be generalized to a wide variety of waste-to-energy projects and provide both policy makers and industry stakeholders with the information needed to identify which projects offer the greatest benefits to Californians.

Conclusions

Despite California’s ambitious commitments to support clean energy, energy equity, and the mitigation of climate pollutants and poor air quality precursors, there remain areas, highlighted by this research, where existing policies and regulations governing waste organics and biomethane are conflicting or non-uniform. This project demonstrates the importance and viability of generating energy from the state’s available biomass residues, as well as the need for locally-tailored distributed bioenergy systems in California to overcome technical and economic hurdles and foster near-term diversion of waste organics from landfills and open burning practices.

Recognizing the potential for distributed generation to meet thermal energy needs both in the urban environment and for industrial sites could be incorporated into policy where appropriate.

For example, developers could be incentivized to consider incorporating biomass distributed generation district heating and cooling in new developments. Feasibility of various strategies for integrating district energy into new developments was discussed with technical advisory committee representatives from the International District Energy Association. Finally, providing the necessary tools to stakeholders that support these efforts, such as planning data and project evaluation criteria will be crucial.

It should be emphasized that the bioenergy conversion scenarios modelled do not maximize the energy production or waste conversion in a given scenario, and they do not represent the total economic potential of technologies such as anaerobic digestion and gasification to convert the state's waste organics to energy. Rather, this project aims to mimic the way California's waste conversion infrastructure is likely to be developed, with lower-cost, more profitable facilities being built first and procuring the most valuable wastes, and additional facilities being built based on remaining available feedstocks. The research team expects outside intervention would be necessary to distribute the most profitable organic waste types to use for biopowered distributed generation across multiple conversion facilities, to maximize the total quantity of waste that can be economically converted to energy. This is particularly significant from the perspective of meeting the state's ambitious organic waste diversion goals.

CHAPTER 1: Introduction

1.1 Overview

California's Senate Bill (SB) 100 California Renewables Portfolio Standard program establishes greenhouse gas emissions mandates for retail and public owned utilities to acquire at least 60 percent of their electricity by 2030 from renewable sources. Furthermore, California SB 1383 requires public utilities to reduce landfilling of organic waste by 75 percent from 2014 levels by 2025. Proper sizing and siting of waste-to-energy projects requires knowledge of the type, spatial distribution, and long-term availability of feedstocks. Chapter 2 presents a method for identifying and mapping volumes of gross and technical waste biomass supply from the agriculture, industrial, and municipal sectors of California. Results include subannual (monthly) and subcounty (fine-resolution, varying based on source) inventories of waste biomass supply in 2014, 2020, and 2050 as well as a characterization of key fuel-related properties of waste residue types, including moisture content (MC) and technical availability.

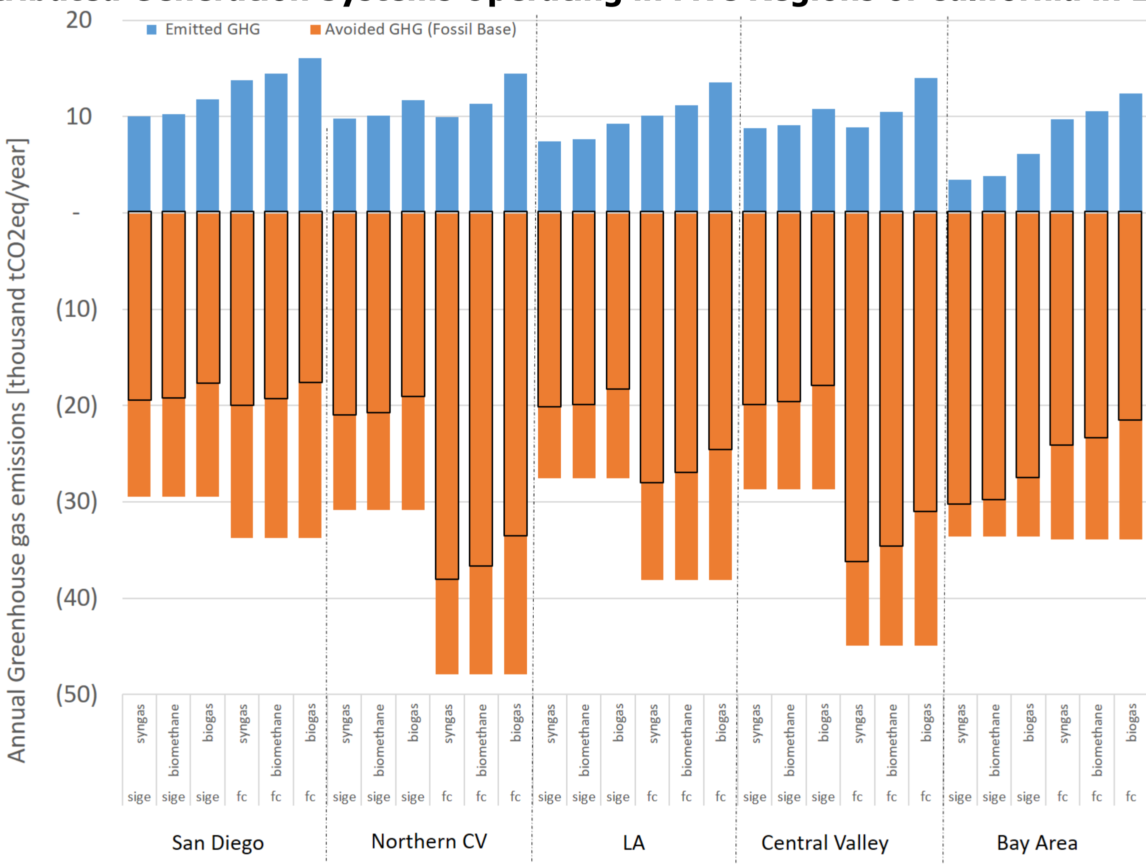
Characterizing the technical, market, and economic viability of distributed energy networks (DEN) that can use the products of waste-to-energy projects (electricity, waste heat, biogas, biomethane) requires highly resolved data on the quantity and distribution of current and future energy end uses. Chapter 3 presents a method to identify the scope and scale for supply of waste heat and waste heat-generated cooling to customers in domestic, commercial, and industrial process markets. Results include projections of thermal energy consumptions in buildings at the tax assessor land-parcel level for 2016, 2020, and 2050. The chapter identifies priority areas where new DEN may be economically viable using screens for thermal energy consumption density and mixed building type and floorspace. Additionally, the potential for expansion or replacement of existing DEN is determined.

Modeling the build-out of waste-to-energy projects requires a technical understanding of commercial and pre-commercial systems for biomass residue transportation, pretreatment, conversion, and power generation. Technology readiness and scalability, including performance limitations and costs, of densification, storage, logistics, conversion, and power generation technologies are reviewed by the project team to support a technical and economic analysis of scenarios for matching biomass residues with the state's power and waste heat needs. Chapter 4 presents an overview of key commercial and pre-commercial technologies relevant to waste biomass use in California. The chapter concludes with a brief discussion on operation decisions for matching biomass feedstocks with the two most mature technologies, anaerobic digestion (AD) and combustion, to give a sense of the challenge of matching feedstocks with conversion technologies and need for managers to have strong technical knowledge or consultants with technical knowledge to ensure efficient, reliable system operation.

Estimating the environmental costs and benefits of organic waste-to-energy systems requires an analysis of the energy and material inputs required to convert organic wastes to valuable forms of energy and to deliver that energy to end uses. Metrics such as carbon or water intensity per unit of energy can then be evaluated for the potential life cycle. The net costs and benefits can only be calculated if theses metrics can be compared with a baseline scenario for organic waste management. This requires knowledge regarding existing and likely future management practices, and their associated environmental impacts. In Chapter 5, techno-economic analysis (TEA) and lifecycle assessment (LCA) methods and results are presented for organic waste-to-energy scenarios. These scenarios are developed using data from the previous chapters and capture differences in potential feedstock, logistics, conversion/ generation technologies, emission controls and cooling systems. Illustrative results of the TEA and LCA capabilities developed by the project team are presented. Chapter 5 provides existing and potential policy and regulatory compliance and impact issues.

While the lifecycle analysis covers all lifecycle stages, it can also be used to explore emissions associated with specific infrastructure. For example, Figure 1 shows results for the operation of distributed generation systems in five regions of California, highlighting the impact operation and equipment selection decisions at the district energy network can make in net reductions in annual greenhouse gas emissions.

Figure 1: Annual Greenhouse Gas Emissions (CO_2eq) Associated with Biopowered Distributed Generation Systems Operating in Five Regions of California in 2050



Emitted emissions reflect direct emissions of carbon dioxide, methane, and nitrous oxide from the use of either syngas, biomethane, or biogas in CHP units, either spark ignition gas engine (SIGE) or fuel cell (FC), and emissions from grid electricity or natural gas fueled boilers purchased to meet annual energy demand. Avoided emissions reflect displaced emissions from the building's baseline use of grid electricity, natural gas fueled boilers, as well as offsets of grid electricity from the sales of electricity from biopowered CHP units. Hallow bars show the difference between the emitted and avoided GHG emissions.

Source: Lawrence Berkeley National Laboratory

The team evaluated model sensitivities and find limited data on emissions factors, particularly from direct syngas and biogas use in combined heat and power (CHP) systems to be a key source of uncertainty. Verification through measurements and monitoring at pilot facilities will play an important role in ensuring the coupling of diverse organic waste types, conversion technologies, and generation technologies perform as expected.

Stakeholders in waste-to-energy currently lack the ability for rapid evaluation of potential Waste-to-Energy sites, including retrofits/expansions of existing facilities or entirely new construction, on the basis of resource availability and potential for waste heat utilization. This requires high-level data for users who wish to survey the whole state for resource-rich regions of interest, as well as very refined data for users who have one or more specific sites in mind and plan to reach out to specific haulers or organic residue-producing locations/entities. Chapter 6 presents a web-based biositing tool that uses outputs of this project to provide this capability to stakeholders. Finally, a preliminary analysis of cost and GHG emissions from onsite wet AD processing is presented for two representative organic waste streams generated at a PepsiCo facility in California.

1.2 Background

1.2.1 Background for the Waste Biomass Supply Assessment

Biomass is defined by federal statute (7 USC 7624 303) as "any organic matter that is available on a renewable or recurring basis, including agricultural crops and trees, wood and wood wastes and residues, plants (including aquatic plants), grasses, residues, fibers, and animal wastes, municipal wastes and other waste materials" (California Biomass Collaborative 2005). Residues from agricultural and forestry activities and from municipalities are produced in all California counties, with current management strategies spanning the spectrum of waste and resource management practices. A resource assessment updated by the California's Biomass Collaborative (CBC) for the California Energy Commission, reported ~78 million bone dry tons (BDT) of residues (including forestry wastes) were produced in 2013, and estimated that ~35 million BDT were technically available for energy generation (After the Knutson and Miller reports, the next California assessment was published by the California Energy Commission in 1992 and updated in 1999 (Tiangco et al 1992; Blackburn et al 1999). In addition to the categories included in Knutson and Miller, municipal solid wastes, and food processing residues were evaluated. An assessment by EERG in 2000 also collected data on biosolids production at wastewater treatment facilities (Springsteen 2000). The CBC, funded by the California Energy Commission, began completing statewide, county level inventories of waste biomass in 2004 (updated 2005, 2006, 2008, 2012, 2015) and included biogas production at landfills and anaerobic digestion facilities (von Bernath et al 2004; Matteson and Jenkins 2007; Williams et al. 2006; Jenkins et al. 2009). A 2014 characterization analysis of municipal solid waste (MSW) (carried out by CalRecycle as part of a series (1999, 2004, 2008 and 2014)), and a 2012 survey of the food processing industry in California have substantially improved knowledge on landfilled and recycled MSW composition, and food processing residue production (Amón et al. 2012). CalRecycle now hosts a disposal reporting system database of reported solid waste disposal (CalRecycle 2018b). The CBC's inventory for 2013 added new information from the food processing survey. The report does not distinguish between residues used for alternative purposes, and residues "lost" to burning practices or those too difficult to collect, although it does distinguish between landfill and diverted waste streams for municipal solid wastes. The report compared the latest CBC statewide inventory to previous assessments, and found that, even when accounting for the effects of population growth and economic activity on residue production, the studies were not directly comparable because of differences in: (1) what biomass categories were included due to the study intent or data availability, and (2) because of differences in assumptions made regarding technical availability.

Figure 2) (Williams et al. 2015).

Upon review, it was determined that a sub-annual, and county or sub-county level analysis would require a more detailed characterization of the types of biomass that comprise larger waste biomass categories. The presentation of results at the annual time scale limits the ability to intersect supply with demand for energy, as power, heating, and cooling demand can vary seasonally and diurnally. Therefore, available data sources and models estimating waste biomass production are reviewed to disaggregate resource production to the sub-annual scale. Despite these limitations, the California Energy Commission study by Williams and colleagues represents the most comprehensive county-scale inventory of waste biomass potential in California, and thus is a valuable starting point for understanding how and why waste biomass production varies across the state (Williams et al. 2015).

1.2.2 Background for the Distributed Generation and Thermal Energy Demand Assessment

Distributed generation (DG) is the production of power and thermal energy close to locations of demand, and reduces dependency on large centralized power plants and transmission systems, captures cogeneration and waste heat potential, and provide opportunities for integrating renewable energy sources into the buildings and industrial energy sector. In California, the 2010 Clean Energy Jobs Plan requires 12 gigawatts (GW) of DG by 2020, and 6.5 GW of additional combined heat and power capacity by 2030. The California Energy Commission estimates there was more than 2 GW of DG potential in CA in 2007, and predicts that 20% of expected increases in power demand could be met by DG in 2020. Annual electricity consumption increased by 50% from 1980 to 2000, and by 16% from 2000 to 2014 (Brown and Koomey 2003; ECDMS 2014). Most of this growth occurred in the commercial sector, followed by the residential sector; industrial consumption decreased by 16%. Statewide, demand grew by around 2% per year from 1980 to 2000, with commercial and industrial sectors being more peak dominated than residential and agricultural sectors. Based on residential energy use intensity, Brown and Koomey estimated that 1 MW of capacity can serve 1200 California homes on average, or 600 homes at peak, although this varied by utility. The potential expansion of DG in California is therefore an important opportunity for integrating renewable energy sources and reducing strain on existing infrastructure.

Waste heat and renewable energy sources like waste biomass are cheap sources of fuel; however, the cost-effectiveness of DG also depends on characteristics of local energy demand. District energy systems (DES) can use DG to provide combined cooling heating and power (CCHP) to buildings through pipe networks, using water as the medium. Locations that have a steady demand for power and thermal energy from buildings allow DES systems to operate at high capacity factors. Ideally, these buildings will be located close together to reduce the required pipeline length, lowering energy losses and pumping costs. The demand for energy per unit area is broadly referred to as energy density, and can be calculated for thermal and electrical demand, as well as for specific end uses, such as space heating and cooling. Potential for DES could be expanded if thermal energy supply technologies such as absorption chillers could be integrated into district network systems to meet energy demand for end uses typically met with electricity. Technologies include absorption cooling and refrigeration, and desiccant dehumidification. This is especially important in mild climates, where space heating is limited (Medrano et al 2008). Identifying high potential locations for early adoption and pilot projects based on geospatial energy density is an important starting point for developers and planners. While a number of approaches exist for estimating energy characteristics of building stocks (as reviewed in Breunig et al. 2018), geospatial techniques for modeling future building stocks and the energy characteristics of future buildings are lacking.

1.2.3 Background for the Densification, Logistics, and Power Generation Review

Supply chains for bioenergy involve the production, collection, transportation, storage, and preprocessing of organic feedstocks from point of production to point of conversion. The value of organic feedstocks as fuels is tied to the preservation or enhancement of fuel qualities and the management of supply chain costs like transportation and preprocessing.

A number of conversion pathways from biomass feedstocks to heat and power are currently technically feasible. The biomass conversion processes included in this report are: (1) direct combustion, including fixed and fluidized bed-based systems; (2) gasification, including fixed and fluidized bed-based systems; (3) anaerobic digestion, including wet and dry systems. In addition to conversion technologies, the combined heat and power (CHP) technology options for gaseous fuels are reviewed. These include technologies such as internal combustion engines, gas turbines, fuel cells, and combined-cycle systems.

Analyses on the state of technologies for biomass pretreatment and transportation, biogas storage, treatment, and transportation, and CHP technologies are scattered throughout disciplines, making it difficult to visualize the decision that a stakeholder may face today or in 2050 regarding technology pathway selection. For example, literature on biomass conversion can provide a general sense of whether a type of waste biomass should be processed using thermo-chemical or biological technologies. However, existing literature does not provide a clear picture of what might affect performance, or what might make a type of biomass typically used in combustion an important co-digestion additive to anaerobic digestion (e.g. straw).

1.2.4 Background for the Cost and Environmental Impact Assessment

Solid organic W2E projects must comply with national Resource Conservation and Recovery Act (RCRA) regulations that lay out criteria for materials recovery, storage and collection, thermal processing, use as fuels, and landfilling. These project also must comply with regulations under the Clean Air Act and the Clean Water Act. At the state level, organic wastes are targeted in the AB 32 California Global Warming Solutions Act Scoping Plan, as the landfilling of organic wastes is a significant contributor of short-lived climate pollutants. Assembly bill 1826, is a mandatory commercial organics recycling bill that sets specific targets for the collection and processing of organic materials, which from the standpoint of this analysis, directly affects the availability and cost of acquiring these materials as fuels. In addition to these national and state regulations, municipalities have their own criteria for how organic wastes are managed, disposed of, or converted and used as products like compost or mulch. Regulations and permitting associated with biomethane pipeline injection are reviewed in this sub-Task. A recent analysis of barriers to biomethane was funded by the California Energy Commission and written by Brian Gannon of Biogas Energy.

Lifecycle Assessment (LCA) is an internationally standardized method to quantify material and energy flows to estimate environmental impacts of any product, process or service. It is a commonly used tool for assessing impacts of industries, like waste management, and can be applied to examine waste-to-energy systems. Net energy (NE) consumption and net greenhouse gas (GHG) emissions are particularly useful metrics quantified using LCA for potential pathways to distributed bioenergy scale-up in the content of the state's energy goals (Kauffman and Lee 2013).

1.3 Report Structure

Each of the four major tasks are presented in Chapters 2 through 5. The analysis is divided into four major Tasks: the waste biomass supply assessment (Chapter 2), the distributed generation and thermal energy demand assessment (Chapter 3), the densification, logistics, and power generation review (Chapter 4), and the cost and environmental assessment (Chapter 5). Results of Chapter 2 are readily available for study and download using a web-based biositing tool that the project team developed. This tool is discussed in Chapter 6, along with a demonstrative case study developed in collaboration with PepsiCo.

Table 1 provides a guide to the project scope and boundaries. The analysis is set in the State of California in the United States for the years 2014, 2020, and 2050. While not possible to be comprehensive, this type of study can shed substantial light on paths to sustainable and equitable distributed generation and bioenergy in California.

Table 1: Project Scope and Boundaries

Waste Types	Conversion Technologies	Energy Products	District Energy Networks	Metrics
• Municipal Solid Waste • Food & Fiber Processor Waste • Agriculture • Biosolids	• Wet AD • Dry AD • WWTF co-digestion • Dairy AD • Gasification • Combustion	• Electricity • Heat • Biogas • Biomethane	• New developments • Expansion of existing • Retrofitting of existing • Fuel switching	• GHG emissions (kg/t-yr) • Non-GHG air emissions (kg/t-yr) • Social cost of carbon ($) • Monetized Benefit of Abatement ($) • Cost ($)

Source: Lawrence Berkeley National Laboratory

CHAPTER 2: Waste Biomass Supply Inventory

2.1 Introduction

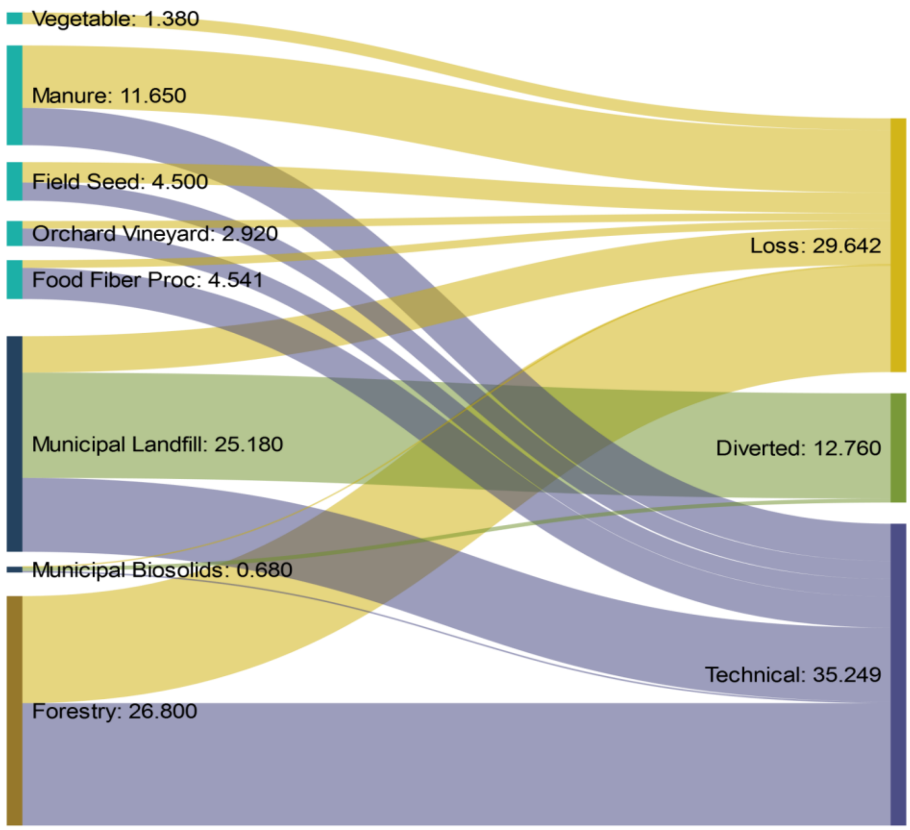
Proper sizing and siting of waste-to-energy projects requires knowledge of the type, spatial distribution, and long-term availability of feedstocks. In this Chapter, a methodology for identifying and mapping volumes of gross and technical waste biomass supply from the agriculture, industrial, and municipal sectors of California is presented. Results of this Task include sub-annual and sub-county inventories of waste biomass supply in 2014, 2020, and 2050 as well as a characterization of key fuel-related properties of waste residue types, including moisture content (MC) and technical availability.

2.1.1 Previous Inventories

Some of the earliest inventories of agricultural waste biomass in California were developed to help identify alternatives to widespread open-burning practices. Knutson and Miller estimated that 10.3 million tons of collectable crop residues, 7.8 million tons of forestry wastes, and 4.4 million tons of manure were generated in 1973 and disposed of through management practices like open burning and soil incorporation (Knutson et al. 1976). Field crops contributed 73% of crop residues, and 33% of total agricultural wastes. The authors collected acreage and production figures from county agriculture commissioner reports and used residue yield multipliers developed in University of California Cooperative extension studies conducted from 1959-1962, and using expert judgement. The authors caution that the values they give are gross production of residues, and should not represent the amount of residue that is economically or sustainably available. Production values are given by season and by county. Knutson and Miller published a second study in 1982 with updated acreage and production values for 1978 that focused on the use of agricultural biomass for energy production (Knutson and Miller 1982). They estimated that 9.1 million tons of crop residues, 7.3 million tons of forestry waste (only include unused mill waste), and 4.3 million tons of manure (from confined animals) were generated in 1978. Sugar beets and lettuce were new. The authors noted that as of 1978, new short-stature rice varieties that had lower residue yields were becoming popular in California, but didn’t update the rice residue yield factor. Residue yield factors for field, fruit and nut, and vegetable crops published in these two reports have been widely used in more recent assessments, including the latest statewide assessment by the CBC, published in 2015 (Williams et al. 2015).

After the Knutson and Miller reports, the next California assessment was published by the California Energy Commission in 1992 and updated in 1999 (Tiangco et al 1992; Blackburn et al 1999). In addition to the categories included in Knutson and Miller, municipal solid wastes, and food processing residues were evaluated. An assessment by EERG in 2000 also collected data on biosolids production at wastewater treatment facilities (Springsteen 2000). The CBC, funded by the California Energy Commission, began completing statewide, county level inventories of waste biomass in 2004 (updated 2005, 2006, 2008, 2012, 2015) and included biogas production at landfills and anaerobic digestion facilities (von Bernath et al 2004; Matteson and Jenkins 2007; Williams et al. 2006; Jenkins et al. 2009). A 2014 characterization analysis of municipal solid waste (MSW) (carried out by CalRecycle as part of a series (1999, 2004, 2008 and 2014)), and a 2012 survey of the food processing industry in California have substantially improved knowledge on landfilled and recycled MSW composition, and food processing residue production (Amón et al. 2012). CalRecycle now hosts a disposal reporting system database of reported solid waste disposal (CalRecycle 2018b). The CBC's inventory for 2013 added new information from the food processing survey. The report does not distinguish between residues used for alternative purposes, and residues "lost" to burning practices or those too difficult to collect, although it does distinguish between landfill and diverted waste streams for municipal solid wastes. The report compared the latest CBC statewide inventory to previous assessments, and found that, even when accounting for the effects of population growth and economic activity on residue production, the studies were not directly comparable because of differences in: (1) what biomass categories were included due to the study intent or data availability, and (2) because of differences in assumptions made regarding technical availability.

Figure 2: Statewide 2013 Annual Residue Production, Gross, Technical, with Losses Due to Either Unspecified Reasons or Diverted, in Million Bone Dry Tons Per Year



Source: Data from Williams et al. 2015; Image created using Sankeymatic.

2.1.2 Waste Biomass Properties for Matching Purposes

Chemical properties that are important when characterizing biomass as a fuel source for thermal conversion processes include: volatile content, fixed carbon, the ultimate analysis (carbon, hydrogen, oxygen composition), moisture content (MC), caloric value, ash and alkali metal content. Moisture content is the fraction of biomass that is water and estimates of moisture content for waste biomass types generated in California are published by Breunig and Colleagues in the supplementary information (Breunig et al. 2018).

The time at which MC is measured is important since the value changes with natural or forced drying. Unfortunately, biomass supply studies rarely clarify whether the MC they use is an intrinsic value, measured in a laboratory setting, or an extrinsic value, measured "at production" or "at harvest". Low moisture solids (LMS) (<55% MC) like nut shells are considered to be more suitable for thermal conversion processes than high moisture solids (HMS) like winery pomace. This is because it takes energy to evaporate water and that energy is lost in the resulting steam unless the steam is somehow captured. A higher heating value (HHV) is energy that is generated by burning a substance in the presence of air, including the latent heat of water produced during combustion, whereas lower heating value (LHV) excludes this latent heat.

The ash content is the mineral fraction of biomass, or the non-carbon solids (ash) that remain after a substance is combusted in air. This fraction is also found in the non-biodegradable solids remaining after anaerobic digestion. The ash content affects the performance and efficiency of energy generation and can lead to operational challenges due to the formation of slag. This is especially true if the alkali metal content of the biomass is high (Na, K, Mg, P). Agricultural residues that are contaminated with soil have higher silica ash contents. Rice hulls have a very high ash content compared to other crop residues. While an important property to consider, this project does not restrict high-ash feedstocks from utilization.

2.2 Feedstock Descriptions

2.2.1 Crop Waste

In this study field crops include seed, grains, rice, cotton, peanuts and dry beans. Hay and silage crops are assumed to generate no recoverable biomass. Row crops include vegetables, melons, berries, herbs, roots and tubers, edible beans, and sweet corn. Orchard and vineyard crops include tree fruits, nuts, grapes, and kiwis.

When crops are harvested, there are typically three categories of biomass that require management: marketable products, culls, and residues (Produce left in the field are referred to in this study as culls, and occur for a variety of reasons. Marketable produce can be left due to inefficient harvesting techniques, or if land goes unharvested. Produce can also be left intentionally if it is rejected for not meeting market standards (nutritional value, color, size, etc.). Finally, a period of natural shedding of fruit or "June Drop" occurs in orchards before the harvest season begins. While the culls from June Drops are small in size compared to fruits picked at harvest, the number of culls can be quite large.

Table 2). The above-ground fraction of the plant that remains once the marketable product is harvested is referred to as residue. Biomass shed voluntarily by the plant (e.g. leaves) or removed by farmers to improve the health and yield of the plant (e.g. trimmings; prunings) are also referred to as residue. Orchard residues can also include whole trees that are removed due to old age, pest or disease damage, or when orchard land is repurposed. According to Knutson and Miller, activities on pear, apple, and fig orchards yield higher biomass per acre (1.43-1.5 BDT/acre-y) than average, while activities on cherry, date, citrus, pistachio, and walnut orchards result in much lower yields (0.26 – 0.65 BDT/acre-y). Corn

(4.04 BDT/acre-y) and rice (3.01 BDT/acre-y) show much higher residue yields than most field and row crops (~0.86 BDT/acre-y).

Produce left in the field are referred to in this study as culls, and occur for a variety of reasons. Marketable produce can be left due to inefficient harvesting techniques, or if land goes unharvested. Produce can also be left intentionally if it is rejected for not meeting market standards (nutritional value, color, size, etc.). Finally, a period of natural shedding of fruit or "June Drop" occurs in orchards before the harvest season begins. While the culls from June Drops are small in size compared to fruits picked at harvest, the number of culls can be quite large.

Table 2: Biomass Types Pertaining to Crop Waste

Type and Subtype	Description
Residue: Orchard & Vineyard	Tree trimmings and prunings; whole trees; leaves
Residue: Field	Stover, stalks
Residue: Row	Vines, leaves, berry bush trimmings
Culls: Orchard & Vineyard	Fruits and nuts
Culls: Field	Potatoes, beets
Culls: Row	Vegetables, ground fruits

Source: Lawrence Berkeley National Laboratory

Previous waste biomass inventories have developed estimates of gross and technical crop residue supply in California, including a series developed by the CBC, summarized by Williams and colleagues (Williams et al. 2015). In the year 2013, crop residues were comprised of 2.9 million BDT orchard and vineyard residue (70% technically available), 4.5 million BDT field and seed crop residue (47% technically available), and 1.4 million BDT row crop residues (0% technically available) (Knutson et al. 1976; Knutson and Miller 1982). Culls are not included in the past inventories. Harvested acreage by crop type and by county are collected from the US Department of Agriculture National Agricultural Statistics Service (NASS), and multiply by residue yield factors from Knutson and Miller. Technical potentials for crop residues are assumed based on rules of thumb and expert judgement in the CBC inventories. A potential of 70% is assumed for all orchard and vineyard residues in the 2013 inventory (Williams et al. 2015). Silage and hay crops are excluded because they are assumed to yield no harvestable residues. Technical availability is assumed to be 50% for all crops except for high moisture leaf and vine residues from potatoes, sweet potatoes, and sugar beets, in which case availability is set at 5%. These factors are determined based on expert judgement that a significant fraction of the organic matter must remain on the field for soil management.

Technical availability of vegetable residues is zero, down from the 5% potential used in previous CBC reports, to account for the likelihood that residues will be used for soil management and for animal feed.

The method used to estimate annual and monthly crop production and culls for 2014, the most recently published harvest year in the NASS database, is described in detail by Breunig and colleagues (Breunig et al. 2017). A "cull multiplier" is developed for each type of crop. In-field losses of grains and oilseeds are not included in this study, as losses are assumed to be too costly to recover. The cull multiplier assumes that total available harvest is equal to the sum of reported production and cull production. This method provides an estimate of the wet-mass and county-scale location of culls throughout the state. Cull multipliers are varied by ±40% to capture ranges in literature summarized by Breunig and colleagues. Culls are converted to BDT by accounting for moisture content. Moisture content for food crops are assumed for culls of the same crop type.

Annual cull production is disaggregated to monthly production using regional and seasonal conversion factors. Counties are grouped by agricultural region as shown in Table in Appendix A. Seasonal conversion factors represent the fraction of annual production generated in each month. Total production is distributed over the days in the harvesting period assuming that 80% of production occurs during the peak harvesting period, unless otherwise specified. Details on seasonal conversion factors can be found in the supporting information of the article by Breunig and colleagues (Breunig et al. 2017; Breunig et al. 2018a).

Harvested crop acreage is converted to residue production using residue yields as was done in the CBC 2013 inventory. Residue yields factors and MC are collected and reviewed from the University of California Agriculture and Natural Resources online catalogue, biomass property databases, and Knutson and Miller (Table 3, Table 4, and Table 5).

Tomatoes, potatoes, unspecified orchard, and grapes generate the most BDT of culls out of all vegetables and fruits. Almonds, grapes, and rice generate the most BDT of residues out of all crops. Generally, row crops produce more culls than residues and orchards generate more residues than culls.

Table 3: Orchard and Vineyard Residue Yields (Prunings) and Moisture Content

Produce Type	Residue Yield (wet-tons/ acre-y)	MC (% wet basis)	Residue Yield (dry-tons/acre-y)	Yield Reference
Apples	1.9	40%	1.2	Voivontas et al. 2001
Apricots	2.5	40%	1.5	Voivontas et al. 2001
Avocados	1.5	40%	0.9	Knutson and Miller 1982; Knutson et al. 1976
Cherries	2.1	40%	1.2	Voivontas et al. 2001
Dates	0.6	43%	0.3	Knutson and Miller 1982; Knutson et al. 1976
Figs	2.2	43%	1.3	Knutson and Miller 1982; Knutson et al. 1976
Grapes	2.0	45%	1.1	Voivontas et al. 2001
Kiwifruit	2.0	45%	1.1	Voivontas et al. 2001
Nectarines	1.6	43%	0.9	Knutson and Miller 1982; Knutson et al. 1976
Olives	1.1	43%	0.7	Voivontas et al. 2001
Peaches	2.3	43%	1.3	Voivontas et al. 2001
Pears	2.3	40%	1.4	Knutson and Miller 1982; Knutson et al. 1976
Persimmons	1.6	43%	0.9	Knutson and Miller 1982; Knutson et al. 1976
Plums & Prunes	1.5	43%	0.9	Knutson and Miller 1982; Knutson et al. 1976
Pomegranates	1.6	43%	0.9	Knutson and Miller 1982; Knutson et al. 1976
All Citrus	2.5	40%	1.5	Voivontas et al. 2001
Almonds	2.5	40%	1.5	Voivontas et al. 2001
Pecans	1.6	40%	1.0	Knutson and Miller 1982; Knutson et al. 1976
Pistachios	1.0	43%	0.6	Knutson and Miller 1982; Knutson et al. 1976
Walnuts	1.0	43%	0.6	Knutson and Miller 1982; Knutson et al. 1976
Fruits & Nuts unsp.	1.6	50%	0.8	Knutson and Miller 1982; Knutson et al. 1976

Source: Lawrence Berkeley National Laboratory

Table 4: Row Crop Residue Yields and Moisture Content

Produce Type	Representative Residue Type	Residue Yield (wet-tons/ acre-y)	MC (% wet basis)	Residue Yield (dry-tons/ acre-y)
Artichokes	tops	1.7	73%	0.5
Asparagus		2.2	80%	0.4
Green Lima Beans	vines and leaves	1.0	80%	0.2
Berries	prunings and leaves	1.3	40%	0.8
Broccoli		1.0	80%	0.2
Cabbage		1.0	80%	0.2
Cantaloupe Melons	vines and leaves	1.2	80%	0.2
Carrots	tops	1.0	84%	0.2
Cauliflower		1.0	80%	0.2
Celery		1.0	80%	0.2
Cucumbers	vines and leaves	1.7	80%	0.3
Garlic		1.0	73%	0.3
Combined Melons	vines and leaves	1.2	80%	0.2
Lettuce and Romaine		1.0	80%	0.2
Dry Onions		1.0	73%	0.3
Green Onions		1.0	73%	0.3
Hot Peppers	stems & leaf meal	1.0	80%	0.2
Sweet Peppers	stems & leaf meal	1.0	80%	0.2
Spices & herbs		1.1	80%	0.2
Spinach		1.0	80%	0.2
Squash	vines and leaves	1.2	80%	0.2
Sweet Corn	stover	4.7	20%	3.8
Tomatoes	vines and leaves	1.3	80%	0.3
Unspecified vegetables		1.4	80%	0.3
Potatoes	vines and leaves	1.2	80%	0.2
Sweetpotatoes	vines and leaves	1.2	80%	0.2
Sugar Beets	top silage	2.4	75%	0.6

Source: Lawrence Berkeley National Laboratory

Table 5: Field Crop Residue Yields and Moisture Content

Produce Type	Representative Residue Type	Residue Yield (wet-tons/ acre-y)	MC (% wet basis)	Residue Yield (dry-tons/ acre-y)	Yield Reference
Corn	stover	2.9	20%	2.3	Voivontas et al. 2001
Sorghum	stover	2.2	20%	1.8	Knutson and Miller 1982; Knutson et al. 1976
Wheat	straw & stubble	1.2	14%	1.0	Voivontas et al. 2001
Barley	straw & stubble	0.9	15%	0.7	Voivontas et al. 2001
Oats	straw & stubble	0.5	15%	0.4	Voivontas et al. 2001
Rice	straw	1.8	14%	1.6	Voivontas et al. 2001
Safflower	straw & stubble	0.9	14%	0.8	Knutson and Miller 1982; Knutson et al. 1976
Sunflower	straw & stubble	0.9	14%	0.8	Knutson and Miller 1982; Knutson et al. 1976
Cotton	straw & stubble	1.5	14%	1.3	Knutson and Miller 1982; Knutson et al. 1976
Beans	vines and leaves	1.0	80%	0.2	Knutson and Miller 1982; Knutson et al. 1976
Lima Beans	vines and leaves	1.0	80%	0.2	Knutson and Miller 1982; Knutson et al. 1976
Cowpeas & South. Peas	vines and leaves	1.0	80%	0.2	Knutson and Miller 1982; Knutson et al. 1976
Soybeans	stover	1.0	20%	0.8	approx.
Rye	straw & stubble	0.5	14%	0.4	Voivontas et al. 2001
Triticale	straw & stubble	1.2	14%	1.0	approx..
Alfalfa	stems & leaf meal	1.0	11%	0.9	Knutson and Miller 1982; Knutson et al. 1976

Produce Type	Represen-tative Residue Type	Residue Yield (wet-tons/ acre-y)	MC (% wet basis)	Residue Yield (dry-tons/ acre-y)	Yield Reference
Bermuda Grass Seed	grass	1.0	60%	0.4	Knutson and Miller 1982; Knutson et al. 1976
Unsp. Field & Seed	stubble	1.0	14%	0.86	Knutson and Miller 1982; Knutson et al. 1976

Source: Lawrence Berkeley National Laboratory

2.2.2 Livestock Waste

Livestock wastes include manure and used bedding materials from livestock including swine, cows, goats, sheep, poultry, horses, and donkeys. Previous waste biomass inventories have developed estimates of gross and technical manure supply in California. The 2013 CBC inventory estimates livestock in California at 66 million poultry, 1.8 million dairy cows, 0.6 million beef cows, and 29 million cows in rotation (replacements, etc.) (Williams et al. 2015). Manure production is estimated to be 10.9 million BDT/y from cattle and 0.7 million BDT/y from poultry. Manure production is calculated by applying average production rates for representative animal types from the ASAE Manure Production Characteristics report. Total solids production from dairy cows is approximated using a weight average of dry and lactating cow production rates, assuming 15% of dairy herds are dry at any given time. This weighted average accounts for the annual calving cycling in dairy cows, where cows are dry the last two months of gestation (thus ~15% of the year). Estimates of manure supply are estimated at the county level for cows and poultry, and at the state level for swine. Wastes from sheep, lambs, and horses have not been included in previous inventories due to low quality/unavailable data. Technical availability factors are conservatively estimated based on whether the livestock type is typically confined or not.

A literature review is conducted to identify ranges in manure yields and how manure yields vary by animal size (Table 60, Appendix B) (Lorimor et al 2004; ASAE 2005; Lawrence et al. 2003; USDA 2008). Data on manure production is collected for sheep and lambs, and equine livestock. Yields assumed by Williams and colleagues for cows, swine, and poultry are multiplied with livestock populations reported in the 2016 survey and the 2012 Census at the county level to estimate manure production.

Scheduling tools for livestock are made available by a number of agriculture extensions, including one at the University of California, Davis. These tools provide example calendars for herd composition, which can help to estimate how manure production may vary from month to month. Table 69 in Appendix B provides an example for beef cattle on rangeland and shows how manure increases by 70% between September and March before declining due to culling and sales. Experts in animal science are being sought to provide feedback on seasonality of manure production, as available calendars are for livestock on rangeland, and not in feedlots where manure is likely to be collected.

Waste from the poultry industry is comprised of bedding materials (straw, sawdust, wood shavings, shredded paper, and peanut and rice hulls), waste feed, manure, broken eggs and feathers, dead birds, and wastewater and solids from slaughter houses. In this study, poultry litter refers to bedding materials and manure. Bedding yields per animal are listed in Table 68 in Appendix B, and reflect the assumptions that each bird is provided one square foot space (to meet the California mandate for humane conditions), and that one inch of bedding is applied and removed weekly. The yield will vary depending on the density of bedding and frequency of removal. Initial bedding estimates are calculated assuming loose non-legume hay is used for 90% of chickens. Manure and bedding are usually combined during collection.

2.2.3 Food and Fiber Processor Waste

The food processing industry includes companies involved in canning-, freezing-, dehydrating-, and prepping-fresh fruit and vegetables, nut processing, alcohol production, non-alcoholic beverage production, bakeries, meat processing, dairy production, sugar refining, and fiber production. Residues from food processors include low (MC under 55%) and high moisture solid wastes and high strength wastewater (Amón et al. 2012; Matteson and Jenkins et al 2007). Wastewater is typically discharged to wastewater treatment facilities, or the biosolids from the wastewater are applied to land or sent to landfills. Biochemical oxygen demand (BOD), commonly given in kg/m^3, is a measure of the amount of dissolved oxygen needed to breakdown organic matter over a given time, and is used to estimate the amount of methane that can be generated from treating the wastewater. Food processing facilities commonly enter long-term agreements with nearby wastewater utilities to lower the financial risk involved in building excess treatment capacity to meet facility's wastewater discharge. It is possible that these agreements will make it difficult for competing bioenergy facilities to acquire the wastewater and biosolids.

Previous waste biomass inventories have developed estimates of gross and technical food and fiber processing residues in California, however the survey-based industry assessment by Amon et al. greatly improved the scope and quality of data on residue production (Amon et al. 2012). The survey data is collected from a 2007 survey of companies in the food processing industry conducted by Dun and Bradstreet, from the Regional Water Quality Control Board (RWQCB) offices, and through personal communication with company representatives and public works agencies. Amon et al. estimates that 26.3 billion gallons of wastewater (174,000 dry tons BOD_5) and 3.4 million dry tons of solid residues are generated annually in California. The CBC 2013 inventory reports gross food processing residues to be 4.4 million BDT/y (80% technical), and gross cotton gin waste to be 0.2 million BDT/y (80% technical).

In the 2013 inventory published by the CBC, residue-to-product multipliers are used to estimate residue production from almonds, walnuts, wine, and rice processing. Fruit and olive pits are excluded due to low quality data. Gross meat processing residues are estimated at 315,860 BDT for 2013, but are not disaggregated to counties. This differs from the 2008 CBC report, which collects county level data from a 2003 phone survey of meat processors, and estimates 79,490 BDT of gross production for 2007. Regarding availability of residues for bioenergy, the CBC assumes 67% of residues from food processors are technically available for bioenergy. If the technical potential of almond hulls is reduced to zero, given strong demand for hulls as an animal feed, then technical potential of food processing residues would be only 36%.

A majority of high moisture solids (HMS) are sent to certified disposal facilities where they are converted into compost, animal feed, or biogas through anaerobic digestion or applied to land to increase soil organic matter. Some HMS is used to create high-value products like protein-rich nutritional supplements. Low moisture solids (LMS), like nut shells and hulls are converted into animal feed and bedding, combusted for energy, or used to create high-value products, as in the case of fruit pits. Amon et al. notes that dairy farms and animal feed operations will be affected if large quantities of food processing residues are diverted to bioenergy production. While the authors did not assess residue availability for bioenergy over a range of prices, they estimate that very little of the residues and wastewater are economically available, and that only fruit and vegetable, and winery wastes have a high potential of being potentially available.

Cotton fiber, or lint, is typically harvested in the fall and sold to cotton gins for processing while cotton seed is sold for animal food production, and for cooking oil production. The husk is removed during the ginning process and sometimes sold as an additive for animal feed. Cotton grown in California is largely American Pima, or ELS cotton, which is used in high-end products and has a higher value than upland cotton grown in the rest of the nation. Williams and colleagues acquires fiber production data from the 2013 NASS California crop report and uses a cotton gin waste residue yield multiplier of 0.83 trash:lint to estimate residue production (Williams et al. 2015). The 2008 CBC report uses an acreage residue yield factor of 0.19 tons/acre-y, which is derived by assuming 150 pounds of trash are produced for every 480 pound cotton bale. A technical availability factor of 80% is assumed in both the 2008 and 2015 CBC reports. Gross production of cotton trash is estimated at 187,190 BDT for 2013 and 128,220 BDT for 2007.

In addition to the categories included in previous assessments, the following new categories are included in this analysis: stone fruit and olive pits, grain chaff, brewery waste, distillery waste, bakery and tortilla waste, nut shells (other than almond and walnut). Meat processing residues are separated into poultry and non-poultry residues. Dairy (whey and lactose) and sugar refining residues are reviewed, but not modeled as these residues are currently treated more like resource than wastes.

The amount of California-grown production of nuts, rice, and cotton that is processed in California in 2014 is estimated using the 2014 NASS California crop report and processing fractions found in literature (Appendix B). Annual production of nut processing waste is estimated by applying shell or hull weight fractions to the fraction of production that is shelled or processed. A different approach is used to estimate almond waste, as production is reported as "shelled" in the NASS data. The wet weight hull and shell fractions listed in Table 7 converted to much higher residue yields than those used in by the CBC. To be conservative, CBC yield values for almond hulls and shells are assumed. A dry weight trash to lint ratio of 0.83 is applied after adjusting for moisture content; this method assumes that the reported production amounts in NASS are not dry-weight, which differs from the CBC 2015, which applies dry weight residue yields directly to production amounts. Olive and stone fruit pit production is assessed using the method presented by Breunig and colleagues (Breunig et al. 2017).

Fruit and vegetable processors, meat processors, bread and tortilla manufacturers, and beverage manufacturers use imports as well as California grown produce, and are modeled using industrial survey data from Amon et al. Values are adjusted to 2013 by accounting for industrial growth between 2009 and 2013 and disaggregating state production to the county level using 2013 employment data.

Table 6: Key Terms and Descriptions Pertaining to Food and Fiber Processing Residues

Type	Sub-Type	
Food Preserving	Canning	culls, trimmings, pits, stems, skins, and seeds; wastewater
Food Preserving	Dehydrators	
Food Preserving	Fresh/Frozen	
Meat	Poultry	feather meal and bones, meat scraps, fats, blood, wastewater
Meat	Non-Poultry	
Beverage	Non-alcoholic	culls, trimmings, pits, stems, skins, and seeds; corn syrup; sucrose; wastewater
Beverage	alcoholic - winery	pomace, wastewater
Beverage	alcoholic - brewery and distillery	spent grains, wastewater
Fiber	cotton	cotton gin trash (husk, twigs)
Nut processors	almond	shells and hulls
Nut processors	walnut	
Nut processors	other nut	
Stone fruit and olive processors	stone fruit pitters olive pitters	pomace, pits, wastewater
Stone fruit and olive processors	olive oil mills	

Source: Lawrence Berkeley National Laboratory

Table 7: Moisture Content and Residue Yields for Nut, Rice, and Cotton Processors

Produce (in Shell)	MC	Shell (wet-wt)	Hull (wet-wt)	% Processed	Trash:Lint (dry-wt)	Reference
Almonds	6%	33%	53%	70%		Cantwell 2014; Godini 1984; Ag. Marketing Resource Center 2015; FAO 1994
Chestnuts	49%	80%		0%		
Pecans	5%	40%		80%		Cantwell 2014; FAO 1994
Macadamia	10%	60%		100%		CRFG 1997
Walnuts, Black	5%	53%		0%		Cantwell 2014; FAO 1994
Walnuts, English	5%	53%		70%		Cantwell 2014; FAO 1994
Rough Rice	14%		18% (dry)	100%		Williams et al 2015
Cotton Lint	8%			100%	83%	Williams et al 2015, Valco et al 2004

Source: Lawrence Berkeley National Laboratory

2.2.4 Organic Fraction of Municipal Solid Waste and FOG

Organic materials in municipal solid waste include food, green waste, lumber, paper and cardboard, and other organics (textiles; remainder and composite organics) (Table 22). State and county inventories of organic fractions of MSW have been estimated in previous waste biomass assessments for California, however results of past studies are difficult to compare due to differences in the organic fractions included, and the addition of improved disposal characterization data over time (Williams et al, 2015). The California Department of Resources Recycling and Recovery (CalRecycle) tracks disposal (landfilling) and disposal related activities including alternative daily cover (ADC), alternative intermediate cover (AIC), other beneficial reuse at landfills, transformation (e.g. to energy), waste tire-derived fuel in the disposal reporting service (DRS) database at the quarter (3 months) and jurisdiction levels. The database does not characterize organic waste fractions in disposed waste. In 2014, CalRecycle completed the first disposal and recycled waste characterization study in 6 years. Subsequent analysis of CalRecyle's characterization study evaluated the quantity, composition, and recyclability of commercial, residential, and self-haul waste streams and the end state of those materials (CalRecycle 2014, CalRecycle 2015a).

The older CalRecycle waste characterization study is used in the CBC 2013 inventory to disaggregated disposed MSW into organic fractions. The inventory estimates of the 13.1 million BDT MSW biomass disposed, there were: 4.7 million BDT/y cardboard and paper, 3.9 million BDT/y lumber, 0.5 million BDT/y leaves and grass, 1.4 million BDT/y prunings, 0.1 million BDT/y branches and stumps, 1.4 million BDT/y food waste, and 1.2 million BDT/y other biomass (including biosolids). The CBC assumes a 67% technical availability factor for biomass recovery from disposed MSW, which is higher than the 50% factor used in past CBC biomass inventories. The inventory does not include diverted organic fractions, assuming that all diverted materials (12.3 million BDT/y) go to recycling markets.

Following the 2014 waste characterization study, CalRecycle determined that 31 million tons of municipal solid waste (MSW), or half of MSW generated in California, ended up at landfills or burned at incineration or "transformation" facilities and that organic materials made up 40% of disposed waste.

Public works agencies and water treatment utilities have conducted a number of locally-focused assessments of urban food processing and food waste collection, several of which are discussed in Amon et al., including reports by the Humboldt Waste Management Authority (HWMA) and the Central Marin Sanitation Agency (CMSA). The Sacramento Municipal Utility District (SMUD) and researchers at UC Davis also completed a resource assessment to evaluate local food Waste-to-energy investments. They estimated that 4.7 MW of electricity could be generated from the wastewater and solid residues that are generated within 50 miles of Sacramento (UC Davis 2005).

A portion of food waste in MSW is comprised of fats, oils, and grease (FOG) from food preparation occurring in the home and in food service locations like restaurants. FOG that are produced during meat processing are typically directed to rendering facilities for animal feed and consumer products, and are not included in this analysis.

Table 8: Key Terms and Descriptions Pertaining to Organics in MSW and FOG

Type	Sub-Type
Lumber	Construction and demolition lumber, other lumber
Food	Food (not Fats, Oils, Greases)
Green	Leaves and Grass; Prunings and Trimmings; Branches and Stumps; Manure
Paper	Paper Bags; Newspaper; White Ledger Paper; Other Office Paper; Other Office Paper; Magazines and Catalogs; Phone Books and Directories; Other Misc Paper; Remainder/Composite Paper
Cardboard	Uncoated Corrugated Cardboard
Other organics	Textiles; Remainder/Composite Organic
FOG	Animal fats, margarine, shortening, cooking and salad oils, other oils

Source: Lawrence Berkeley National Laboratory

Methods for estimating FOG production at the county level are discussed by Breunig and colleages (Breunig et al 2017). Consumption rates of FOG per capita per day are collected for: animal fats, margarine, salad and cooking oils, shortening, and other oils from the ERS 2013 database and used to approximate FOG purchases. The fraction of purchased FOG that is disposed is then approximated using consumer-level loss factors of fats and oils published by the USDA National Nutrient Database. Factors for each category of FOG are then multiplied by county population data from the US Census Bureau to estimate waste FOG supply.

Comparing the county level production of FOG to the county level production of food waste in MSW revealed that between 1% and 4% of total food waste in MSW is expected to be FOG. This is lower than previous estimates of the fraction of FOG making up food waste: 10% assumed by Greg Kester of CASA.

Wet tons of MSW disposal is converted to fractions of biomass assuming the 2014 composition of MSW and using moisture contents listed in Table 9.

Table 9: Assumed Characteristics of Organic MSW Fractions

Sub-Type	Moisture Content	Green Waste Composition
Paper/cardboard	10%	
Food	78%	
Leaves and grass	60%	41%
Other organics	4%	
C&D lumber	15%	
Prunings, trimmings, green ADC	40%	34%
Branches and stumps	40%	18%
Manure	86%	7%

Source: Lawrence Berkeley National Laboratory

2.2.5 Landfill Gas

Williams and colleagues estimate net recoverable landfill methane to be between 71 and 53 billion ft^3/y. They estimate 75% of the gas is technically recoverable. Historical waste-in-place (WIP), and biogas yields are estimated from CalRecycle disposal rates, statewide population and USEPA AP42 recommendations. A model similar to the LandGEM model developed by the US EPA is used to estimate gas from WIP data. This analysis uses county-level methane generation values from the inventory published by Williams and colleagues as a starting point, however future work should include a review of new models that capture variations in biogas composition and yields over time.

This analysis does not model changes in landfill gas capture, and focuses on the evaluation of biogas and biomethane production from organic wastes diverted from landfills.

2.2.6 Municipal Wastewater Treatment-Derived Biogas and Biosolids

The CBC 2013 inventory estimates that annual methane production from sewage treatment at wastewater treatment facilities (WWTF) is 7.3 billion ft^3; it is assumed that 95% of the methane is technically recoverable. Flow rates at WWTF with AD facilities are multiplied by a biogas yield of 1.15 ft^3/100-gallons wastewater to estimate biogas potential. It is assumed that 65% of the biogas is methane.

Several estimates of existing excess capacity for biomass digestion at WWTF are reviewed in Breunig et al. For example, the Waste-to-Biogas tool developed by the EPA estimates potential excess capacity at California WWTF and the potential methane generation from processing additions of FOG. They estimate that 30.3 million ft^3/d (11 billion ft^3/y) of additional methane could be generated.

CalRecycle estimates that 723,000 BDT of biosolids were generated in 2013, based on an analysis from the California Association of Sanitation Agencies (Kester 2016). Most biosolids (56%) are used as soil amendments and fertilizer, while 13% is landfilled, and 19% is used as ADC. The remaining fractions are surface disposed, incinerated, used as fuel, or deep well injected. Gross biosolids disposal and diversion are reported in the 2013 inventory by Williams et al as being: 220,000 BDT/y landfilled, and 460,000 BDT/y diverted. However, the methodology and data sources used to determine biosolids are unclear. Only eleven counties are reported as generating biosolids, but WWTF with AD capacity is distributed among a majority of counties. The CBC estimates that 80% of diverted biosolids and 67% of landfilled biosolids are technically available for bioenergy.

Three wastewater treatment facility databases are critically reviewed in Breunig et al. Data on design flow capacities and average dry weather flow capacities are cross-references and cleaned, and facility capacities are aggregated to the county level. Using the CBC's assumptions on methane production at WWTF, ~9.5 billion ft^3 methane/y is generated if design flow capacities are converted, and 6.9 billion ft^3 methane/y if average flow capacities are converted.

A biosolids generation factor (BFG) of 206 bone dry tons per million gallons per day [MGD] is assumed in this analysis (187 BDT/MGD). This unit allows the capacity at wastewater treatment facilities to be used to estimate annual biosolids generation. It is adapted from a detailed analysis of biosolids generation and biosolids generation factors in conducted 1999 by the EPA. Results are listed in Table 75 in Appendix B.

2.3 Project Waste Biomass Supply Inventory

2.3.1 Crop Waste

Biomass residues are a product of industrial, commercial, and residential activities, and are managed as wastes when they cannot be treated as valuable by-products. Changes in these activities and the political and physical environment in which they occur will drive biomass residue production and disposal. This study identifies and models key driving forces of biomass residue production. Baseline projections of biomass residue supply in 2020 and 2050 are developed by extending business as usual trend into the future.

2.3.1.1 Drivers Assessment

Agricultural land use and management, and the yield of crops on agricultural land, are tied to a number of complex, interconnected driving forces. Consumer preference and disposable income, taxes and subsidies, water resources, and global markets, all drive the planting and harvesting of individual crops. The crop yield is affected to varying degrees by drivers like the plant variety selected, water and nutrient availability, night temperatures, diseases, pests, pollinator abundance, and farming practices. While there is a wealth of literature on the sensitivity of crops to environmental changes, particularly the effects of climate change on water resources and temperature, many studies focus on either a specific change, such as pollinator abundance, or a select set of changes with varying consistency as the to the coverage of crop types in California. No studies have modelled the impact of these driving forces on crop residue. In fact, very little research has been conducted on how residue yields may change when crop yields are improved through technology.

The California Department of Agriculture recently conducted a literature review of challenges that may arise from the direct and indirect impacts of climate change. Another study modeling future crop production out to 2050, evaluated the significance of climate change, improvements in agricultural technology, urban development, and water markets on crop yield and agricultural revenue (Medellin-Azuara et al 2011). Despite expected improvements in crop yields due to improved management, fertilizers, and irrigation systems, their study found that crop yields are likely to decline by 2050 for most crop types. Outputs of past analyses are useful for understand the vulnerability of certain crops to climate and market changes. However, studies vary in their underlying assumptions and in the applicability of their results for different locations and crop types. Strategies to mitigate the effects of climate change on crop yields may be available for some crops and limited for others.

2.3.1.2 Projection Method

Historical data is gathered from the USDA's National Agricultural Statistics Service, California Field Office which summarizes County Agricultural Commissioners' Annual Crop Reports from 1980 to 2014. Harvested acreage, yield, and other statistics are provided for individual crops at the county level. This data is used to develop a baseline projection of orchard, vineyard, row crop, field crop, and pasture harvested acreage and yields.

In the baseline projections, any projected change in produce yields (tonnes/acre) results in a correlated change in cull yields. In other words, if production goes up, cull production also goes up as it is assumed that increased production is not a result of more effective harvesting techniques. An alternative scenario will decouple produce yield and culls production, and look at how any increase in produce yield may be due to a decrease in culls. Produce is converted to dry weight [BDT] residues using residue per acre yield fractions and residue MC (Table 3, Table 4). This analysis assumes a steady production of residues year to year (i.e. maintenance practices are seasonal and not inter-annual). Large changes in harvested acreage tend to be dominated by only a few crop types in each of the three categories (orchard, field, row).

Orchards and vineyards are comprised of perennials with long lifespans, resulting in smoother trendlines in harvested acreage [acres/year] that can be used to predict near-term values. Values for harvested acreage in 2016, 2020, and 2050 are extrapolated using linear regression on county level harvested acreage data from 2005-2014 (48 produce types). Extrapolated values are constrained in two ways: values never exceed 30% of the maximum historical value (7% of 2050 county level crop projections are corrected to meet this constraint), and negative trendlines expected to reach zero acreage by 2050 will only reach the minimum historical value if the county has never had zero harvested acreage (4% of projections are corrected). Values for 2014 are used to represent 2016 and 2020 when county data does not fit a linear relationship; the maximum, average, or minimum from 2005 to 2020 is then used to represent 2050 depending on the statewide trend in that produce type. If 2014 has zero harvested acres, it is assumed that the farms do not recover from recent drought and market conditions by 2016 or 2020 and that acreage remains at zero. A minimum value is used for 2050 if there was any harvested acreage between 2005 and 2020 assuming that some orchard and vineyard land may be replanted by 2050.

Orchard and vineyard historical yield [tons produce per acre per year] data can provide information on the performance of plants in an area, while long term changes in yields can provide information on improvements in harvesting practices. County level yield data from 1980 to 2014 is assessed to identify trends. Similar to how acreage is extrapolated, yields in 2016, 2020, and 2050 are extrapolated using linear regression to model positive or negative linear relationships. An average yield is assumed if there is no clear trend. This study assumes yields reported as zero reflect a year with no harvest, and are therefore not included. Extrapolated values are constrained so that values never exceed 50% of the maximum historical yield (1% of values are corrected). This is a conservative constraint, as over 45% of county aggregated yields increased by 50% or more since 1982.

Aside from berries, row crops are annuals, resulting in higher variability in planted and harvested acreage from year to year. Values for harvested acreage in 2016, 2020, and 2050 are extrapolated using linear regression on county level harvested acreage data from 2005-2014 (106 produce types). Extrapolated values are constrained in two ways: values never exceed 30% of the maximum historical value (2% of values are corrected to meet this constraint), and negative trendlines expected to reach zero acreage by 2050 will only reach the minimum historical value if the county has never had zero harvested acreage (1% of values are corrected). Values for 2014 are used to represent 2016 and 2020 when county data does not fit a linear relationship; the maximum, average, or minimum from 2005 to 2020 is then used to represent 2050 depending on the statewide trend in that produce type. If 2014 has zero harvested acres, it is assumed that the farms do not recover from recent drought and market conditions by 2016 or 2020 and that acreage remains at zero. Three to five year cycles of low and high productivity appear in certain crops in a number of counties, frequently including berries, squash, spinach melons, and eggplant. If cycles are present, 2016 and 2020 are modeled assuming the frequency and amplitude remain the same.

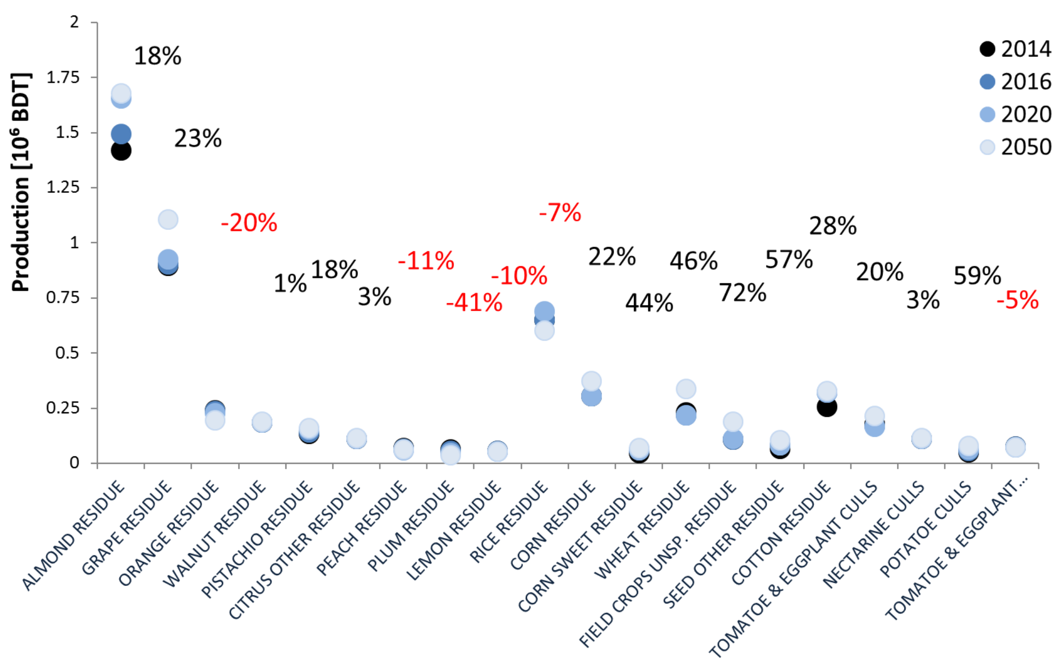
Row crop historical yield [tons produce per acre per year] data can provide information on the performance of plants in an area, while long term changes in yields can provide information on improvements in harvesting practices. County level yield data from 1980 to 2014 is assessed to identify trends. Similar to how acreage is extrapolated, yields in 2016, 2020, and 2050 are extrapolated using linear regression to model positive or negative linear relationships. An average yield is assumed if there is no clear trend. This study assumes a zero yield does not reflect on the lands productivity, but on human actions or unexpected events, and are therefore not included. Extrapolated values are constrained so that values never exceed 50% of the maximum historical yield (1% frequency). This is a conservative constraint, as over 25% of county aggregated yields increased by 50% or more since 1982.

Field crops are annuals, resulting in higher variability in planted and harvested acreage from year to year. Values for harvested acreage in 2016, 2020, and 2050 are extrapolated using linear regression on county level harvested acreage data from 2005-2014 (83 produce types). Extrapolated values are constrained in two ways: values never exceed 30% of the maximum historical value (1% of values are corrected to meet this constraint and negative trendlines expected to reach zero acreage by 2050 will only reach the minimum historical value if the county has never had zero harvested acreage (1% of values are corrected). Values for 2014 are used to represent 2016 and 2020 when county data does not fit a linear relationship; the maximum, average, or minimum from 2005 to 2020 is then used to represent 2050 depending on the statewide trend in that produce type. If 2014 has zero harvested acres, it is assumed that the farms do not recover from recent drought and market conditions by 2016 or 2020 and that acreage remains at zero. For many crops, harvested acreage is stable until the drought, upon which harvested acreage dropped. An average value is used for 2050 if there was any harvested acreage between 2005 and 2020 assuming that field land is replanted by 2050.

2.3.1.3 Scenario Results

Baseline projections for orchards and vineyards show 10% growth in harvested acreage, 13% growth in residue BDT, and 81% growth in cull production between 2014 and 2050 at the state level. Projections for row crops show 1% growth in harvested acreage, 7% growth in residue BDT, and 35% growth in cull production between 2014 and 2050 at the state level. Projections for field crops show 14% growth in harvested acreage and 19% growth in cull production between 2014 and 2050 at the state level. Results at the county level are summarized in Table 76 -Table 91. These results reflect increasing production yields (and thus cull yields in the baseline scenario) expected in orchards and vineyards, and moderately increasing production yields in row crops.

Figure 3: Baseline Projected Changes in Production of the 20 Largest Generators of Crop Waste



Changes between 2014 and 2050 are shown as percentages.

Source: Lawrence Berkeley National Laboratory

2.3.2 Food and Fiber Processor Waste

2.3.2.1 Drivers Assessment

Food and fiber processors in California are affected by national and international market trends. Consumer behavior and disposable income, taxes and subsidies, the price of raw products, and appreciation of the dollar are key drivers for food and fiber industries. Perceived nutritional value is a major factor affecting food processors in the short and long term. Americans continue to shift from red meat to poultry and fish, and from preserved food to fresh and organic produce. Simultaneously, an increase in per capita disposable income and time spent on leisure and sports has resulted in an increase in the fraction of food that is consumed out of the home or prepared quickly from frozen meals. Demand for all alcoholic beverages is expected to rise, with noticeable growth in demand for California wines, craft beers, and spirits. Crop losses resulting from unexpected factors such as floods, disease and pests, and extreme temperatures can lead to sharp changes in processor production rates. However, these factors are difficult to capture at the industry level as food processors vary in their ability to acquire alternative sources of raw produce.

IBISWorld publishes industrial reports by NAICS code annually, which assess key drivers of revenue and employment, and estimates future trends and annual growth in revenue out four years. National trends are assumed to be strong indicators of California trends, as a significant portion of food and fiber is produced in California to meet national and international demand. Recent trends in key external drivers are listed in Table 10, along with the expected impact on revenue for relevant industries.

2.3.2.2 Projection Method

Industrial reports and statistics on employment, revenue, and industrial production are reviewed to identify and model key drivers of food and fiber productivity and growth. California state employment forecasts for food and fiber industries developed by the State of California Employment Development Department (EDD) are evaluated along with national trends in revenue, as revenue and employment tend to respond similarly to external drivers in the food and fiber industry (notable industry exceptions seen between 2008 to 2016: wineries, dairies, bakeries). The California EDD publishes employment by NAICS code out to 2024 for the state and to 2022 or 2024 for some counties and regions (Table 10). These market indicators are compared with historical data on the national Industrial Production (IP) Index, publish quarterly in an online database by the Board of Governors of the Federal Reserve System (Table 11). The IP index measures real output from manufacturing sectors using: data on inputs to manufacturing processes; measured physical output; production-worker hours. Quarterly updates are published on the IP index and Capacity Utilization for fruit and vegetable preserving and specialty food, dairy product, animal slaughtering and processing (including separate values for beef, pork, and poultry processing), beverage and tobacco product (including separate values for breweries), bakeries and tortillas, and other food.

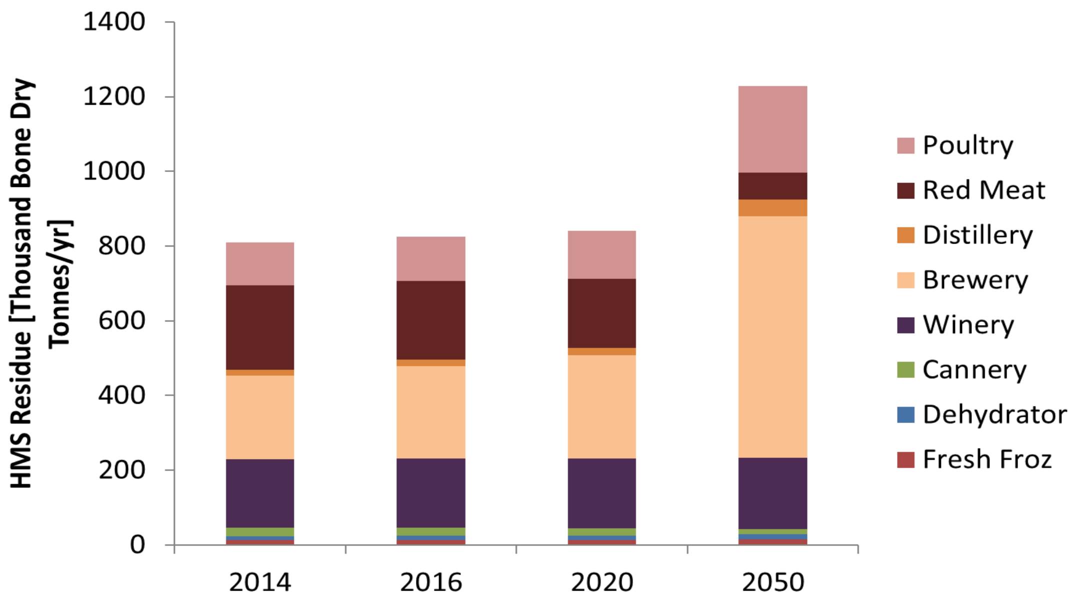
As a starting point, it is assumed that residue production changes proportionally to the national industrial production. The annual change in IP index from 2011 to 2015 is used to estimate growth out to 2016 and 2020 assuming residue production is directly correlated to manufacturing output. The annual change in IP index from 2013 to 2014 is used to estimate growth out to 2050 assuming recent years reflect a stronger economy. Estimates are made for industries without an industrial production index, based on industrial performance reports and California employment trends. Specifically, annual growth in frozen and dehydrated fruits and vegetables, and bakeries and tortilla manufacturing is modeled using revenue projections.

Baseline projections of harvested acreage and yields are used to model production of nut, rice, and cotton processing residues in 2016, 2020, and 2050 (it is assumed that these processors primarily process California grown produce). This method assumes two important things: (1) residue yields do not change over time; (2) the county in which residue production occurs is the county where the farm is located. The location of food processing facilities changes over short periods of time, making the location of future food processing residues at the county level highly uncertain. This study does not attempt to predict changes in food processer locations from 2013 sites. The team assumes waste from the dairy industry and sugar refining are not "wastes" and go to animal feed or other established markets.

2.3.2.3 Scenario Results

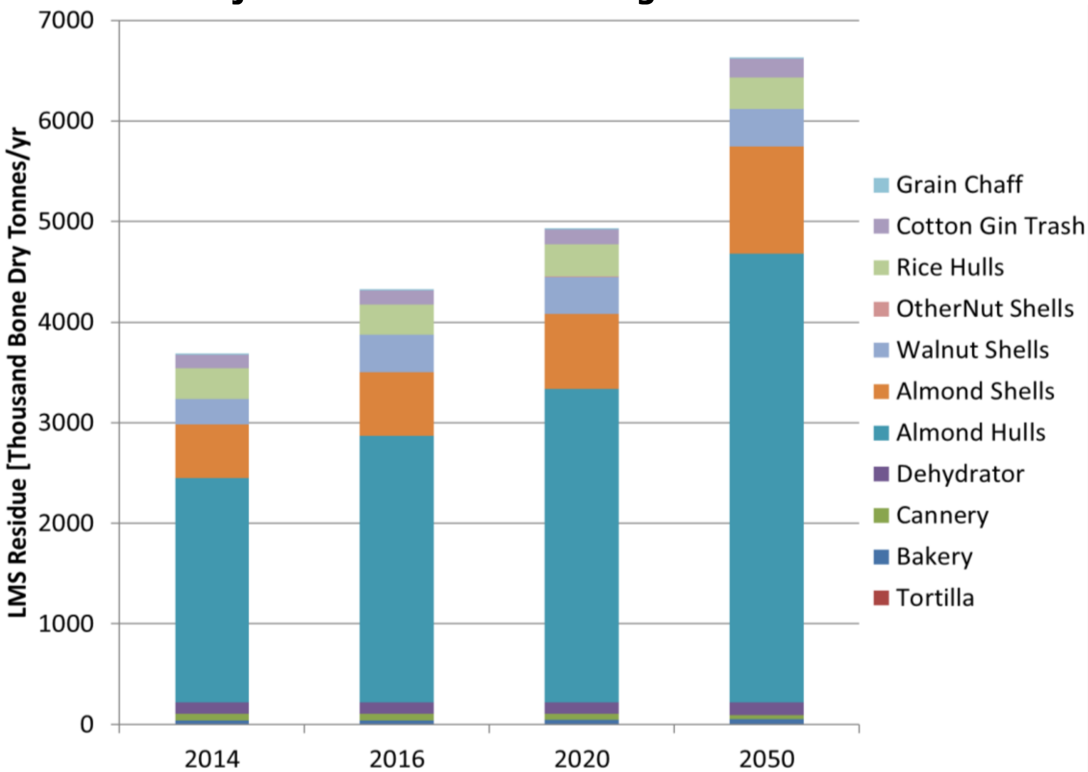
Poultry slaughter and processing, distillery, and brewery residues are projected to grow by over 100% by 2050. Wineries residues will increase by less than 5%, while high moisture dehydrator and fresh/frozen residues will increase by between 10 - 30%. Red meat slaughter and processing residues are expected to drop by 68% and cannery high moisture residues are expected to drop by 38%. Out of all the low moisture residues, only cannery low moisture residues are expected to decrease. Enormous growth in almond shells and hulls (100%), and tortilla residues (200%) are projected, which reflect increasing average almond yields (50%) and harvested acreage (18%), and rapid growth of the tortilla industry in recent years.

Figure 4: Baseline Projection of Food Processing High Moisture Residue Production



Source: Lawrence Berkeley National Laboratory

Figure 5: Baseline Projection of Food Processing Low Moisture Residue Production



Source: Lawrence Berkeley National Laboratory

Table 10: Key External Drivers Affecting Food and Fiber Processing Industries and their Revenue Correlation

Key External Drivers	Near-Term Trend	Industry	Revenue Correlation	IBISWorld#
Healthy Eating index	increase	Bakery	-	31181
		Cannery	-	31142
		Poultry	+	11235
		Dehydrator	+	OD4641
		Frozen	-	31141
time spent on leisure and sports	increase	Frozen	+	31141
consumer price index	increase	Tortilla	+	31183
per capita disposable income	increase	Cannery	-	31142
		Bakery	+	31181
		Frozen	-	31141
per capita fruit and vegetable consumption	increase	Cannery	+	31142
		Dehydrator	+	OD4641
per capita poultry consumption	increase	Poultry	+	11235
per capita beef consumption	decrease	Beef	+	11211
per capita wheat flour consumption	decrease	Bakery	+	31181
		Distillery	+	31214
per capita expenditure on alcohol	increasing	Distillery	+	31214

Key External Drivers	Near-Term Trend	Industry	Revenue Correlation	IBISWorld#
price sugar	uneven	Cannery	-	31142
price vegetables	increase	Cannery	net +	31142
		Dehydrator	-	OD4641
price of fruit	increase	Cannery	net +	31142
		Dehydrator	-	OD4641
price of corn	decrease	Tortilla	net +	31183
price of synthetic fiber	increase	Cotton	+	11192
price of coarse grain (barley, oats, sorghum)	decrease	Brewery	-	31212
		Distillery		31214
world price of wheat	decrease	Tortilla	net +	31183
		Bakery	-	31181
world price of cotton	increase	Cotton	net +	11192
price of poultry	increase	Poultry	+	11235
price of red meat	decrease	Beef	-	11211
price of feed	uneven	Poultry	-	11235
	decrease	Beef	-	11211
trade-weighted index	increase	All	-	
agriculture price index	decrease	Frozen	-	31141
demand from grocery wholesaling	increase	Cannery	+	31142
demand from soft drink, baked goods, and other grocery wholesaling	increase	Tortilla	+	31183
demand from meat, beef, and poultry processing	increase	Poultry	+	11235
		Beef	+	11211
demand from beer wholesaling	increase	Brewery	+	31212
demand from beer, wine, and liquor stores	increase	Winery	+	31213
demand from bars and nightclubs	increase	Winery	+	31213
excise tax on wine	decrease	Winery	-	31213
excise tax on beer	decrease	Brewery	-	31212
excise tax on distilled spirits	decrease	Distillery	-	31214
subsidies for cotton farming	decrease	Cotton	+	11192

Source: IBISWorld Report numbers are listed for 2016

Table 11: Projected Annual Growth Rates in National Revenue and State and/or County Employment

Annual Growth Rate	Revenue [IBISWorld 2016]		Employment [EED 2016]
	2011-2016	2014-2022	
Food Manufacturing			0.46%
El Dorado			-0.7%
Fresno			1.2%
Kern			0.5%
Los Angeles			-0.3%
Placer			-0.7%
Riverside			0.9%
Sacramento			-0.7%
San Bernardino			0.9%
San Joaquin			-1.9%
Stanislaus			-1.5%
Yolo			-0.7%
Rest of State			0.9%
State			0.5%
Dairy Product Manufacturing	-0.9%	-2.4%	0.6%
Los Angeles			-0.4%
Fruits and Vegetable Processors			-1.3%
Canneries	0.8%	2.4%	
Frozen	1.6%	0.6%	
Dried /Dehydrator	1.4%	0.3%	
Beverage and Tobacco			3.1%
Winery	1.9%	0.1%	
Brewery	6.7%	0.9%	
Distillery	6.1%	0.5%	
Animal Slaughtering and Processing			0.6%
Los Angeles			-1.3%
Chicken and Turkey	5.6%	2.6%	
Hog and Pig	6.3%	2.0%	
Beef Cattle	6.4%	-1.2%	
Bakeries and Tortilla Manufacturing			0.5%
Los Angeles			-0.3%
Bakeries	0.3%	0.4%	
Tortillas	2.2%	3.2%	
Other Food Manufacturing			2.8%

Sources: This table uses values from IBISWorld 2016 industrial report series and the EDD employment forecasts.

Table 12: Annual Change in Industrial Production Index

Years	Fruit and Vegetable Preservation and Specialty Food	Dairy	Animal Slaughter and Processing	Beef	Pork	Poultry	Other food	Beverage and Tobacco Product	Brewery	Bakeries and Tortilla
10-11	-1.1%	-0.8%	2.8%	0.9%	2.8%	4.8%	2.4%	-0.2%	0.9%	0.9%
11-12	3.4%	2.9%	-5.0%	-7.5%	-4.5%	-2.8%	-1.5%	2.4%	2.9%	-0.7%
12-13	2.8%	-0.4%	1.8%	-0.6%	-0.1%	4.8%	1.8%	0.8%	10.1%	2.2%
13-14	-1.0%	-0.8%	-2.1%	-4.2%	0.1%	-1.5%	2.3%	-2.4%	6.9%	1.3%
14-15	-8.0%	0.6%	3.6%	-1.9%	7.8%	5.5%	2.3%	1.3%	-1.2%	1.1%
11-15	-0.8%	0.6%	-0.5%	-3.4%	0.7%	1.5%	1.2%	0.5%	4.9%	1.0%

Sources: FRS G.17 2017.

2.3.3 Organic Fraction of Municipal Solid Waste and FOG

2.3.3.1 Drivers Assessment

Total municipal solid waste (MSW) disposal is driven by a number of variables including: population, wages, real personal consumption expenditures, taxable sales, unemployment, and housing. While per-resident and per-employee disposal rates have declined, total disposed waste is expected to increase with a strengthening economy and population, unless curbed by increased source-reduction and recycling. California Department of Resources Recycling and Recovery (CalRecycle) developed three scenarios out to 2025 of futures with either strong economic growth, business as usual, or strong recycling policy impacts on total MSW disposal rates (Table 14). A Medium Growth scenario (or business as usual) assumes the per capita disposal rate stays at the recent historical average of 4.7 lb per person per day (compared to the rate in 2014 of 4.5 lb per person per day). The Low Growth scenario reflects achievement of the 75% Recycling goal by 2020 and assumes the per capita disposal rate declines to 2.7 lb per person per day by 2020. The High Growth scenario reflects an economic boom and assumes per capita disposal reaches 7 lb per person per day by 2020. The rates modeled in 2020 are used to estimate 2050 total disposal.

Ultimately, changes in the disposal rate of individual organic fractions will drive changes in total MSW disposal, but only total disposal is reported and assessed in California. This study develops simple approximations of how changes in the sectors that generate organics may affect organic disposal rates. For example, construction and consumer spending result in organic wastes like lumber, food, cardboard packaging, and "other organics". Demand for paper products has continued to decline as more people use online communication and save materials as digital files. Policy on waste reduction and diversion play an important role in driving down the amount of waste entering landfills. In 1989, California passed the Integrated Waste Management Act (AB 939), which created a comprehensive statewide reporting, inspection, and permitting system for solid waste facilities and required jurisdictions to implement programs to achieve 50% waste diversion from landfills by 2000. The state is currently meeting the 50% diversion goal, however certain activities, such as using green waste for alternative daily cover (ADC) at landfills are counted as diversion. In 2011, AB 341 established a new statewide recycling goal of 75% by 2020 that places responsibility on the state, rather than on jurisdictions, to meet the recycling goal. The Bill required that CalRecycle oversee mandatory commercial recycling, and track statewide recycling rates using a lower baseline disposal rate of 10.7 pounds per person per day (the average disposal rate from 1990 to 2010). Several laws affecting organics have been passed to help the state reach the 75% recycling goal. An organics recycling law, AB 1826 requires businesses to recycling organic wastes on and after April 1, 2016 based on a decreasing generation cutoff rule. Assembly Bill 1594 requires that, beginning in 2020, green material for ADC will no longer count as diversion. Table 13 lists regulatory and non-regulatory factors affecting organic fractions of MSW disposal rates.

Table 13: Drivers of MSW Disposal Resulting in Impacts on Organic Fraction of 2014 Per Capita Disposal

Waste Type	Non-Regulatory Drivers	Regulatory Drivers
Lumber	*Linear 26% increase by 2020 proportional to construction boom *2020 rate steady to 2050	*Building Standards Codes require 50% diversion construction in 2015 *2016 Cal GreenUp: 65% diversion as of 2017 *Assume 80% diversion as of 2050
Food	*1% shift per year from residential to commercial as more people eat out to 2020 *2014 rate steady to 2050	*Assume food conservation awareness in single family residential lowers food waste by 10% as of 2020 and by 60% as of 2050 (1/3 from food prep assumed to be more difficult to decrease) *Regulations on recycling organics in commercial and multifamily residential begin in 2016 resulting in 10% decrease as of 2016, 20% decrease as of 2017, 50% decrease as of 2020, 75% decrease as of 2050
Green	*Linear 50% decrease by 2050 due to drought and urbanization	*Regulations on recycling organics in commercial and multifamily residential begin in 2016 resulting in 10% decrease as of 2016, 20% decrease as of 2017, 50% decrease as of 2020, 75% decrease as of 2050
Paper	*-1.8% growth until 2020 matching average annual growth in IP Index for paper mills 2012-2015.	*Assume programs achieve 25% diversion as of 2020 and 50% diversion as of 2050 by eliminating subtypes identified by CalRecycle as "easy targets", specifically Remainder/Composite Paper
Cardboard	*1.5% growth per year until 2020 matching average annual growth in IP Index for paperboard containers 2012-2015.	*Assume programs keep disposal rates stable as of 2020 *Assume 50% diversion by 2050
Other Organics	*2.1% growth per year until 2020 matching average annual growth in IP Index 2012-2015	*Regulations on recycling organics in commercial and multifamily residential begin in 2016 resulting in 10% decrease as of 2016, 20% decrease as of 2017, 50% decrease as of 2020, 75% decrease as of 2050

Sources: CalRecycle 2016 a,b; FRS G.17 2016

Policy on waste reduction and diversion play an important role in driving down the amount of waste entering landfills. In 1989, California passed the Integrated Waste Management Act (AB 939), which created a comprehensive statewide reporting, inspection, and permitting system for solid waste facilities and required jurisdictions to implement programs to achieve 50%

waste diversion from landfills by 2000. The state is currently meeting the 50% diversion goal, however certain activities, such as using green waste for alternative daily cover (ADC) at landfills are counted as diversion. In 2011, AB 341 established a new statewide recycling goal of 75% by 2020 that places responsibility on the state, rather than on jurisdictions, to meet the recycling goal. The Bill required that CalRecycle oversee mandatory commercial recycling, and track statewide recycling rates using a lower baseline disposal rate of 10.7 pounds per person per day (the average disposal rate from 1990 to 2010). Several laws affecting organics have been passed to help the state reach the 75% recycling goal. An organics recycling law, AB 1826 requires businesses to recycling organic wastes on and after April 1, 2016 based on a decreasing generation cutoff rule. Assembly Bill 1594 requires that, beginning in 2020, green material for ADC will no longer count as diversion.

Table 14: Statewide Total MSW Disposal Rates Estimated Assuming CalRecycle Low, Medium, and High Scenarios

Total Disposal [wet-kg/capita/year]	2014	2015	2016	2020
Low Growth	744	695	646	447
Medium Growth	744	778	778	778
High Growth	744	814	883	1,159

Sources: CalRecycle 2016a, FacIT

2.3.3.2 Projection Method

Two scenarios are developed in this analysis: (1) a baseline (business as usual) scenario that extends recent disposal and recycling trends; (2) an aggressive recycling scenario that meets passed and proposed recycling legislation and goals. These scenarios use the historical total disposal data for 2014 and 2015 from the DRS database, and the 2014 CalRecycle organic disposal fractions for residential, commercial, and self-haul waste streams as a starting point for estimating per capita organics disposal rates. These rates are then modified under the two scenarios and applied to 2016, 2020, and 2050 population estimates published by the California Department of Finance. The estimated impact of driving forces on per capita disposal rates are shown in Table 15.

Historical data for county-level total disposal in 2014 and 2015 are used to capture variations in per capita disposal at the county level. There are several unique characteristics of these year that worth noting. Disposal in 2014 and 2015 broke several years of declining disposal in most of the state, and this change is attributed to a strengthening economy and higher disposable income leading to increased disposal. Changes between 2013 and 2014 for the following counties show the effects of a recent closure of one of the largest landfills in the state, the Puente Hills Landfill: Los Angeles, San Bernardino, Orange, Riverside, San Diego, Kern, Ventura. The decrease in disposal in Los Angeles, and increases in disposal due to new imports in the other counties are not assumed to correlate with the strengthening economy.

Table 15: Per Capita MSW Disposal in 2014 by Region

Region	Per Capita Disposal [dry-kg/capita/yr]
State	595
Bay Area	605
Coastal	539
Mountain	491
Southern	552
Valley	612

Source: Lawrence Berkeley National Laboratory

2.3.3.3 Scenario Results

Despite increased future lumber, cardboard, and textile disposal rates and increasing population, organics disposal increases modestly from 14.5 million BDT/y in 2014 to 15.4 million BDT/y in 2050 in a baseline scenario. This is due to consumer recycling awareness resulting in a decoupling of economic growth and disposal rates by 2020, and decreased paper consumption and green waste, which combined make up 36% of disposed organics in 2014. In a scenario with aggressive recycling mandates and goals, total bone dry organics disposal decreases 45% by 2050. Food waste is the largest component of organics disposal on a wet weight basis, but has very high moisture content and contributes minimally to BDT. Lumber, paper, textiles, and green waste are relatively clean, low moisture materials that make up a majority of organics disposal on a dry weight basis in both baseline and aggressive recycling scenarios.

Per capita organics disposal rates projected in both baseline and aggressive recycling policy scenarios decrease (Table 16). Non-organic wastes like plastics will also experience changes between 2014 and 2050, ultimately resulting in a very different blend of materials in disposed waste than what is characteristic of 2014 disposal. In 2014, organics including lumber and excluding carpets made up 65% of total disposed waste. However, the amount of organics projected to be disposed of in 2016 in this studies aggressive recycling scenario adds up to 83% of the 2016 MSW disposal estimated in the CalRecycle low growth scenario. It is unlikely that other materials in MSW, such as plastics, have decreased enough to allow organics to comprise 83% of wet-weight disposed in 2016. Therefore, it is assumed that this result indicates that additional local initiatives, regulations, and consumer behavior beyond what is modeled in this study is needed to meet the CalRecycle low growth scenario (and thus meet the state’s 75% diversion by 2020 goal).

Historical MSW disposal per capita in 2014 shows little variation between regions (Table 16), while disposal per capita varies from 7 dry-kg/capita/year in Tulare to 101 dry kg/capita/year in Mono at the county level (outliers may also be due to reporting errors however). Total organics disposal is projected to increase between 20 and 30% in Southern, Coastal, and Mountain counties (Table 17).

Table 16: Project Statewide Disposal Rates of Organic MSW [wet-kg/capita/yr]

Waste Type	Historical Estimate			Baseline		Recycling Impacts		
	2014	2015	2016		2014	2015	2016	
Lumber	89	92	95	103	103	89	62	35
Food	134	140	135	135	135	126	88	42
Green	68	71	68	66	55	65	49	34
Paper	105	109	103	96	56	98	72	28
Cardboard	23	24	23	25	25	23	23	12
Other	62	64	63	66	54	60	50	34

Source: Lawrence Berkeley National Laboratory

Table 17: Projected Growth in Annual Regional Organic Material Disposal [BDT/yr] Between 2014-2050

Region	Total Organics	Lumber	Paper	Cardboard	Food	Green	Other
Bay Area	12%	51%	-30%	42%	32%	5%	16%
Coastal	24%	84%	-24%	54%	43%	14%	16%
Mountain	27%	101%	-26%	51%	41%	12%	16%
Southern	22%	77%	-25%	53%	42%	13%	15%
Valley	8%	45%	-33%	37%	27%	1%	15%

Source: Lawrence Berkeley National Laboratory

2.4 Conclusions

This chapter provides an overview of waste biomass inventories and projections for California, excluding forestry wastes, and presents the methods and results used to estimate gross and technically available waste biomass supply for California out to 2050. Supply scenarios are used in the subsequent analysis to estimate Waste-to-energy project viability and siting.

New categories of waste are added in this analysis, and an inventory is developed for 2014. In addition to the waste biomass categories included in previous assessments of California’s biomass resource, the following new categories are included in this analysis: stone fruit and olive pits, grain chaff, brewery waste, distillery waste, bakery and tortilla waste, nut shells (other than almond and walnut). Meat processing residues are separated into poultry and non-poultry residues. Dairy (whey and lactose) and sugar refining residues are reviewed, but not modeled as these residues are currently treated more like resource than wastes. Methods for projecting crop wastes, food and fiber processing wastes, and the organic fraction of MSW are developed, and results are presented at the county level for 2020 and 2050; the results of which can be found in Breunig et al. 2018 and downloaded from the project’s web-based biositing tool. Deep dives into waste production and energy potential from the food supply chain, as well as estimates of excess capacity at anaerobic digesters and solid biomass combustion facilities are completed in this Task; the results of which can be found in Breunig et al. 2017.

Gross waste biomass production totals ~35 million bone dry tonnes (BDT) per year for the state in 2014. Between 7 and 10 billion ft^3 methane/y are generated at wastewater water treatment facilities from the anaerobic digestion of sewage sludge and other wastewater accepted at facilities. Additionally, net recoverable landfill methane is estimated to be between 71 and 53 billion ft^3/y in 2013 (Williams et al. 2015). Manure (11 million BDT/y) and organics from MSW (13 million BDT/y) are the largest sources of total solids in the state. Despite the addition of a number of new categories of waste biomass, including culled agricultural produce, brewery and distillery spent grain, grain chaff, stone fruit and olive pits, and fats, oils, and grease (FOG), estimated gross waste biomass production is 9% lower than the value reported in the most recent waste biomass inventory published in 2015 by the California Biomass Collaborative (CBC). Values reported in this study are much lower for field residues (61% lower) and row crop residues (77% lower), primarily as a result of assuming lower field residue yields and higher moisture content (MC) for row crop residues. Residue yields and the time at which moisture content is measured (e.g. right at harvest, post-collection, lab sample) are key sources of uncertainty in this type of analysis.

Baseline projections for orchards and vineyards show 10% growth in harvested acreage, 13% growth in residue BDT, and 81% growth in cull production between 2014 and 2050 at the state level. Projections for row crops show 1% growth in harvested acreage, 7% growth in residue BDT, and 35% growth in cull production between 2014 and 2050 at the state level. Projections for field crops show 14% growth in harvested acreage and 19% growth in cull production between 2014 and 2050 at the state level. Specific residues types, such as woody residues, stover, stalk, hulls, and culls are expected to increase statewide, however declines are detected when assessed at the crop and county level. For example, the changes in residue types between 2014 and 2050 varies depending on whether only the 20 largest residue sources are evaluated, or all crops are evaluated.

Poultry slaughter and processing, distillery, and brewery residues are projected to grow by over 100% by 2050 as consumers shift from red meat to lean meats, and as the fraction of disposable income spent on alcohol rises. Wineries are less impacted by the change in disposable income, and residues increase by less than 5%. High moisture dehydrator and fresh/frozen residues will increase by between 10 and 30%, reflecting a preference for fresh or dehydrated produce as snacks. Red meat slaughter and processing residues are expected to drop by 68% and cannery high moisture residues are expected to drop by 38%, reflecting their difficulty in competing with products perceived to be healthier. Out of all the low moisture residues, only cannery low moisture residues are expected to decrease. Enormous growth in almond shells and hulls (100%), and tortilla residues (200%) are projected, which reflect increasing average almond yields (50%) and harvested acreage (18%), and rapid growth of the tortilla industry in recent years.

Despite increased future lumber, cardboard, and textile disposal rates and increasing population, organics disposal increases modestly from 14.5 million BDT/y in 2014 to 15.4 million BDT/y in 2050 in a baseline scenario. This is due to consumer recycling awareness resulting in a decoupling of economic growth and disposal rates by 2020, and decreased paper consumption and green waste, which combined make up 36% of disposed organics in 2014. In a scenario with aggressive recycling mandates and goals, total bone dry organics disposal decreases 45% by 2050. Food waste is the largest component of organics disposal on a wet weight basis, but has very high moisture content and contributes minimally to BDT. Lumber, paper, textiles, and green waste are relatively clean, low moisture materials that make up a majority of organics disposal on a dry weight basis in both baseline and aggressive recycling scenarios.

Gross resource estimates are presented in the supporting tables. Technical availability factors are useful for getting a sense of logistical challenges and market competition, and are used to convert the gross waste biomass inventory into technically available biomass inventory for the subsequent waste-to-energy analysis.

Table 18: Projected Baseline Changes in Crop Wastes Categorized by Residue Types

Residue Type	Top 20	All Crops
Woody Residue	13%	12%
Rice Residue	-7%	
Stover, Stalks, Straw	41%	19%
Row Culls	29%	35%
Orchard Culls	3%	46%
Vines, Leaves	-5%	6%

Results are presented for the 20 largest sources of waste biomass, and for all crops.

Source: Lawrence Berkeley National Laboratory

CHAPTER 3: Distributed Generation and Thermal Energy Demand Inventory

3.1 Introduction and Background

Characterizing the technical, market, and economic viability of Distributed Energy Networks that can use the products of waste-to-energy projects (electricity, waste heat, biogas, biomethane) requires highly resolved data on the quantity and distribution of current and future energy end uses. In this chapter, a method is presented for identifying the scope and scale for sale of waste heat and waste heat-generated cooling to customers in the domestic, commercial, and industrial process markets.

3.1.1 Previous Studies of Heating and Cooling Demand in California Buildings

Estimating the distribution and intensity of heating and cooling consumption in current and future building stocks is necessary for calculating market potential of DG technologies and renewable-fueled district energy systems. A number of statewide analyses of heating and cooling consumption and demand in California have been performed, but outputs from these analyses are not readily downscaled to smaller spatial resolutions. For example, the Energy Commission regularly publishes projections of building electricity consumption by building type and, in the case of residential buildings, by end use (Table 19).

Table 19: Forecasts of Consumption and Peak Demand for Planning Areas in 2020

Planning Area	Consumption (GWh)			Peak (MW)		
	Low	Med	High	Low	Med	High
PGE	115,908	120,090	124,374	24,715	25,866	26,749
SCE	104,247	108,600	113,791	23,649	24,875	25,871
SDGE	22,225	23,204	24,224	4,913	5,188	5,437
SMUD	11,207	11,639	12,121	3,219	3,387	3,532
LADWP	25,788	26,772	27,815	5,926	6,279	6,542

Sources: ECDMS 2014.

Utility statewide end use load shapes for all sectors in California are also available, developed by Brown and Koomey using the HELM model. Additionally, aggregate statewide load shapes were calibrated using data in utility peak coincident system load reports submitted to FERC. High resolution modeling and mapping of heating and cooling demand has been hindered by the fact that building and energy data is typically private, proprietary, or doesn't exist because it is not collected at the right level. This inhibits estimates of the marginal changes resulting from DES expansion as well as alternative DG technology deployment (such as biomass-fueled DG). Efforts to acquire and integrate utility data into geospatial analysis and databases have begun to develop for populous areas in California like Los Angeles and San Francisco (Kavgic et al 2010; Pincetl et al 2015; SF Environment 2017).

3.2 Characterization of California Building Stock

3.2.1 Current Building Stock

Building floorspace for California has been estimated from regional surveys like CBECS, RECS, and MECS, and from household and housing unit data from the ACS. Table 20 shows square footage data for commercial buildings in the Pacific Region, which includes Washington, Oregon, and California. These values can be disaggregated to sub-regional levels using population or employment, although these are crude scaling factors. Alternatively, data on the building stock can be purchased from county tax assessors.

Data on building stock in the United States exists at the building-level because property is subject to real estate tax, which is calculated based on the assessed value of property. City and county tax assessors are responsible for keeping records of property attributes and ownership transactions for land parcels. A parcel is a quantity of land used for tax assessment purposes with known geometry and geographic location (latitude and longitude). A lot represents a unique subdivision of property that can share, lie within, or span parcel boundaries. Buildings have unique address codes, and are linked to parcels through an assessor's parcel number (APN). However, the comprehensiveness and quality of building attribute data varies, with data relevant to tax assessment processes being of higher quality. Challenges associated with data cleanings are discussed in the SI.

In this task, land and building attributes collected by California Tax Assessor County Offices are acquired as geospatial files from the data vendor ParcelQuest in 2016. Building floorspace reported in parcels is then classified into 19 building use types and 10 building vintages using county-level use codes, build age, and reported past retrofits (ECDMS 2014). Use types and vintages are selected that match commercial building prototypes used in the California Energy Commission Energy Consumption Forecasting model. Floorspace in tax-exempt parcels is classified as "miscellaneous", except for parcels which are confirmed to be tax-exempt higher education institutions "college" through geocoding the addresses of large (class 4 or 5) institutions. Building floorspace is approximated from lot areas in four counties, Alpine, Imperial, Mendocino, and Santa Clara, where building use type but not floorspace is reported. Floorspace is not modeled in two rural counties, Del Norte and Mariposa, which did not provide building use type data. Building years are assigned for all parcels with a reported building floorspace and no build year using a random value from a sample distribution of building ages in nearby Census Block Groups.

The 2016 parcel building stock is a little over 10 billion ft^2, with 41 percent residential, 25 percent commercial, 21 percent industrial (including warehouses), 9 percent miscellaneous, and 2 percent vacant. Half of all commercial floorspace, over 50 percent of all industrial floorspace, and over 80 percent of all residential floorspace with a reported construction year was built prior to 1981 (Figure 6). Only 2 percent of floorspace for each of the three categories was built on or after 2011. All building types have become larger on average over time (Figure 7), which aligns with the findings of national building surveys like CBECS.

Figure 6: Percent of Total Floorspace by Effective Construction Year

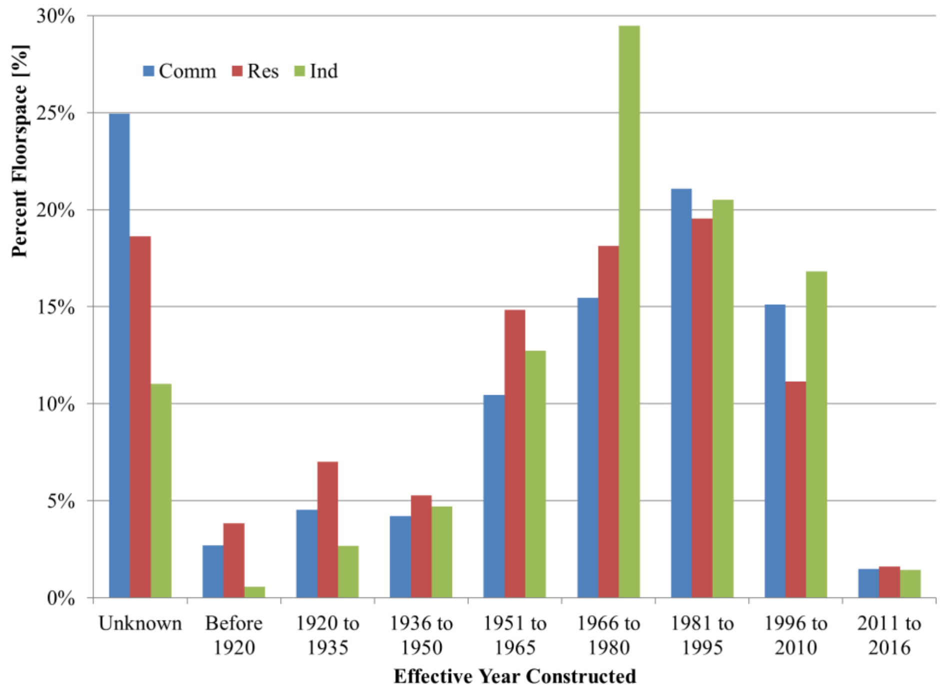


Figure excludes floorspace without a reported build year.

Source: Lawrence Berkeley National Laboratory

Figure 7: Average Size of Buildings by Effective Year of Construction

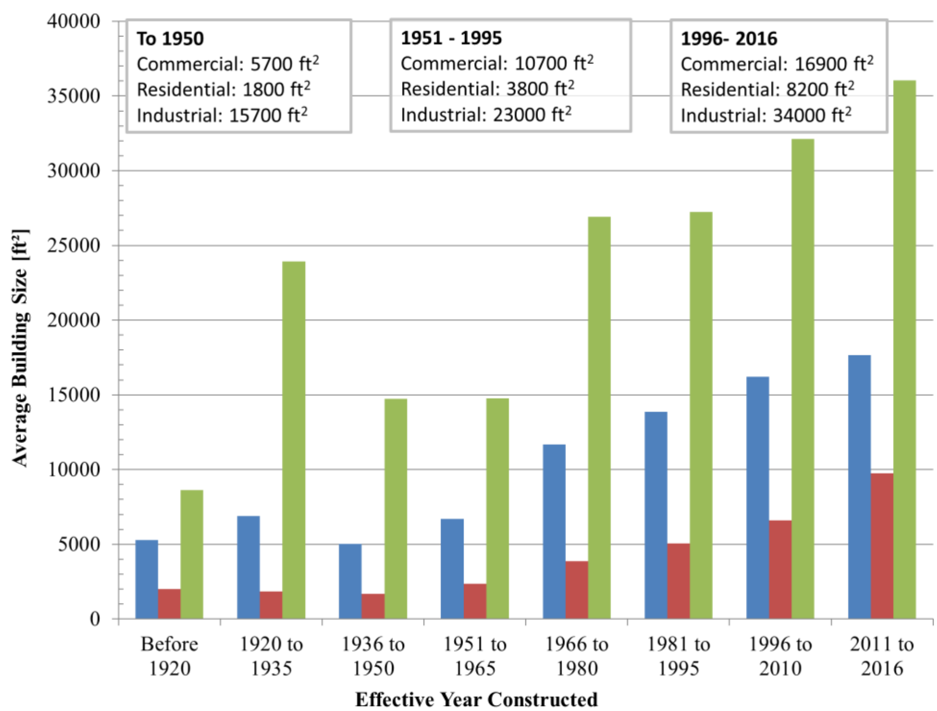


Figure excludes floorspace without a reported build year.

Source: Lawrence Berkeley National Laboratory

Table 20: Commercial Building Stock Characteristics for the Pacific Region

Building Type	Building Type	Number of Buildings	Number of Buildings % of total	Square Footage Total [ft^2]	Square Footage Mean [ft^2/building]	Square Footage % Total
All buildings	1113	928928	100%	13,450,933,724.21	14,480.06	100%
Vacant	40	33611	3.62%	395,596,722.16	11,769.72	2.9%
Public order and safety	16	12058	1.30%	177,123,317.63	14,689.74	1.3%
Religious worship	42	52123	5.61%	510,999,509.33	9,803.82	3.8%
Public assembly	63	61331	6.60%	697,589,961.41	11,374.19	5.2%
Education	120	93827	10.10%	1,065,797,104.63	11,359.21	7.9%
Food sales	22	24178	2.60%	304,029,532.88	12,574.42	2.3%
Food service	61	58882	6.34%	282,568,189.57	4,798.89	2.1%
Outpatient	32	17767	1.91%	181,833,123.26	10,234.47	1.4%
Inpatient	51	1423	0.15%	316,689,122.26	222,549.30	2.4%
Nursing	14	4486	0.48%	139,455,531.33	31,083.58	1.0%
Lodging	49	21934	2.36%	802,637,471.59	36,593.30	6.0%
Data center	0	0	0%	-	-	0%
Office	237	179309	19.30%	2,595,724,046.87	14,476.28	19.3%
Stripmall	52	30076	3.24%	875,825,369.64	29,119.99	6.5%
Enclosed mall	5	211	0.02%	209,992,175.76	995,457.98	1.6%
Other retail	63	60717	6.54%	1,029,789,562.18	16,960.42	7.7%
Service	54	77533	8.35%	578,447,376.76	7,460.68	4.3%
Non-refrigerated warehouse	163	172143	18.53%	2,842,314,448.06	16,511.36	21.1%
Refrigerated warehouse	2	374	0.04%	98,935,029.92	264,677.64	0.7%
Laboratory	12	2806	0.30%	102,251,873.49	36,445.88	0.8%
Industrial	0	0	0%	-	-	0%
Agricultural	0	0	0%	-	-	0%
Residential	0	0	0%	-	-	0%
Parking Garage	0	0	0%	-	-	0%
Other	15	24139	2.60%	243,334,255.49	10,080.34	1.8%

Source: Lawrence Berkeley National Laboratory

3.2.2 Building Stock Projections to 2020 and 2050

Several methods for projecting building floorspace at the regional or state scale in California have been published. These methodologies are discussed in the SI. Historical and projected employment data published by the Employment Development Department for California is collected at the smallest geographical area provided for commercial and industrial industries. Employment data for municipal areas (sometimes representing multiple urban areas in different counties) is allocated to individual counties using total county employment as a weighting factor. A linear regression is performed to estimate growth out to 2050 for each county and industrial sector. The change in employment for each industry between 2016 and 2020, and between 2020 and 2050, are used as approximations of the percent change in associated floorspace [SI]. Steady state is assumed (no change in active floorspace) if a county is missing forecast data for a specific industry; this assumption is varied in the sensitivity analysis. Change in multi-family floorspace is estimated at the county-level using an approach adapted from McCarthy et al., which projects growth in the California single-family and multi-family housing stock (McCarthy et al. 2008). County population projections, persons-per-household, and total household projections are from the California Department of Finance. Net additional households are split into single-family and multi-family new construction according to trends published by the annual publications of California construction review, Construction Industry Review Board.

3.2.3 Building Stock Turnover and Scenarios

The following sections describe the methodology and model used to project and map building stock demolition, construction, and vacancy changes, as well as building floorspace, age, and use type in each land parcel. A program developed in R automates the process and generates output table and shape files that are imported into Microsoft Excel and ArcGIS. Changes in floorspace are first estimated at the county level using aggregate data from the base building stock, and then allocated to parcels through a hierarchical process that prioritizes the replacement of old buildings and vacant lots over the construction of floorspace on undeveloped land. This approach sequentially models each projection year, so that changes to parcels in one year are reflected in future years.

Several key simplifications are assumed: (1) active commercial and industrial floorspace changes proportionally with sector-specific employment rates; (2) active multi-family (MF) residential floorspace can be determined from changes in population, densification (fraction of residential construction that is MF versus single family), and household size (occupants); (3) buildings are demolished when they reach the end of their lifespan; (4) a rebuild will have the same use type as the previous building and will be the same size or larger; (5) buildings are not demolished due to changes in employment, but left vacant or repurposed.

Floorspace reported in the 2016 parcels is aggregated by building type and county to represent the 2016 building stock. Values are multiplied with county-level growth rates for each building use type to determine total floorspace in 2020 (Equation 1).

$$2020\ Floorspace_{i,j} = \left(\sum_k 2016\ Floorspace_{i,j,k}\right) * r_{i,j} \tag{1}$$

where i = county, j = use type, k = APN, and r is the growth rate between 2016 and 2020.

Demolished floorspace is determined from the parcel data, and is the sum of floorspace for buildings that reach their average life span by 2020, as determined by the effective build year. Remaining floorspace is then used to determine the total active floorspace that must be added or subtracted from the parcel data (i.e. unmapped future floorspace changes) (Equation 2).

$$2020\ Floorspace_{i,j} - \left(\sum_k 2016\ Remaining\ Floorspace_{i,j,k}\right) = Unmapped\ Floorspace_{i,j} \quad (2)$$

Positive unmapped floorspace is met with rebuilds of demolished floorspace, construction of buildings in open lots, activation of vacant buildings, and new construction, in that order (5). To do this, unmapped floorspace is divided by total demolished floorspace to estimate a "rebuild multiplier" (Equation 3). The 2020 multiplier is constrained to 4 to keep building growth in a specific land parcel within range of past building development (multipliers are adjusted to 8 in sensitivity analysis). For building types with multipliers between 1 and 4, the demolished floorspace in the county is multiplied to determine each parcels' new floorspace in 2020. Effective build years are adjusted to 2020. Multipliers less than 1 indicate some economic growth, but not enough growth to warrant rebuilds of all demolished buildings. For counties and building types with multipliers less than 1, the positive additional floorspace is met by selecting parcels with the largest demolished floorspace, and assigning new floorspace by a factor between 1.2 and 4, increasing by 0.2, until the required county level floorspace addition is met. This assumes that land with large demolished buildings is more likely to be rebuilt than land with small buildings.

$$Rebuild\ Multiplier_{i,j} = \frac{Unmapped\ Floorspace_{i,j}}{\left(\sum_k 2016\ Demolished\ Floorspace_{i,j,k}\right)} \quad if \leq 4\ AND \geq 1 \quad (3)$$

In cases where additional floorspace is required to meet expected county level growth (multiplier greater than 4), floorspace is allocated to parcels with empty lot areas and vacant buildings. Lot areas are first converted to allowable building sizes using the median floorspace-to-lot area ratio for that building type and county (Equation 4). Then, adjusted lot areas that are as close to the positive additional floorspace required as possible are selected, and effective build years are adjusted to 2020. Following the exhaustion of lot areas, parcels with both a vacant use type and with remaining floorspace in 2020 are selected to meet positive additional floorspace. Then, floorspace is allocated to parcels with vacant use type and no reported building floorspace, adjusting vacant lot area to allowable building size. Any remaining floorspace is recorded in a spreadsheet as additional greenfield "development", but not allocated to parcels. It is assumed that non-industrial buildings will not be converted to industrial use types, so additional floorspace needs for industrial buildings are only met with rebuilds, construction on industrial open lots, and greenfield development.

$$Adjusted\ Empty\ Lot\ Floorspace_{i,j} = \left(\sum_k Lot\ Areas_{i,j,k}\right) * BtoL_{i,j} \quad (4)$$

A negative additional floorspace indicates that there is a greater expected decline in total floorspace by 2020 than what is determined from the parcel effective build years. For these cases, parcels with buildings remaining in 2020 are selected for vacancy until the total active floorspace in the parcels matches the projected floorspace.

$$
\begin{aligned}
&Final\ 2020\ Floorspace_{i,j} \\
&\quad = \left(\sum_k 2016\ Remaining\ Floorspace_{i,j,k}\right) + \left(\sum_k Rebuild\ Floorspace_{i,j,k}\right) \\
&\quad + \left(\sum_k Filled\ Lot\ Area\ New\ Construction_{i,j,k}\right) \\
&\quad + \left(\sum_k Filled\ Vacant\ Floorspace_{i,j,k}\right) - \left(\sum_k Deactivated\ Floorspace_{i,j,k}\right) \\
&\quad + New\ Construction_{i,j}
\end{aligned}
\tag{5}
$$

The same procedure for developing the 2020 building stock is used to develop the 2050 building stock, with 2020 as the starting parcel set.

3.3 Building Thermal Energy Demand

3.3.1 Building Prototypes

Building prototypes developed in this study provide energy consumption profiles for buildings of a specific use type, vintage, and climate zone. In this study, energy consumption is characterized for electricity and natural gas for the following end uses: space heating, water heating, space cooling, industrial process cooling, industrial process heating. Building use types suitable for DES are multifamily residential buildings (including condominiums), commercial buildings (including institutions like colleges), industrial buildings, and large miscellaneous buildings.

The following sections discuss the energy determinants that are used to develop and assign EUIs to parcels (Figure 8). A literature review of methodologies and databases is conducted to determine ranges in EUIs for relevant residential, commercial, and industrial buildings, and published in Breunig et al. 2018. Given that electricity and natural gas are the dominant fuel types used in California buildings, other fuels like fuel oil are not considered in this analysis.

To estimate heating and cooling demand in buildings, electricity and fuel consumption must be converted to thermal demand. A coefficient of performance (COP) of 6 is assumed for electric cooling systems in commercial and industrial buildings, and 3.5 in residential buildings, and an efficiency of 0.8 is assumed for all natural gas systems.

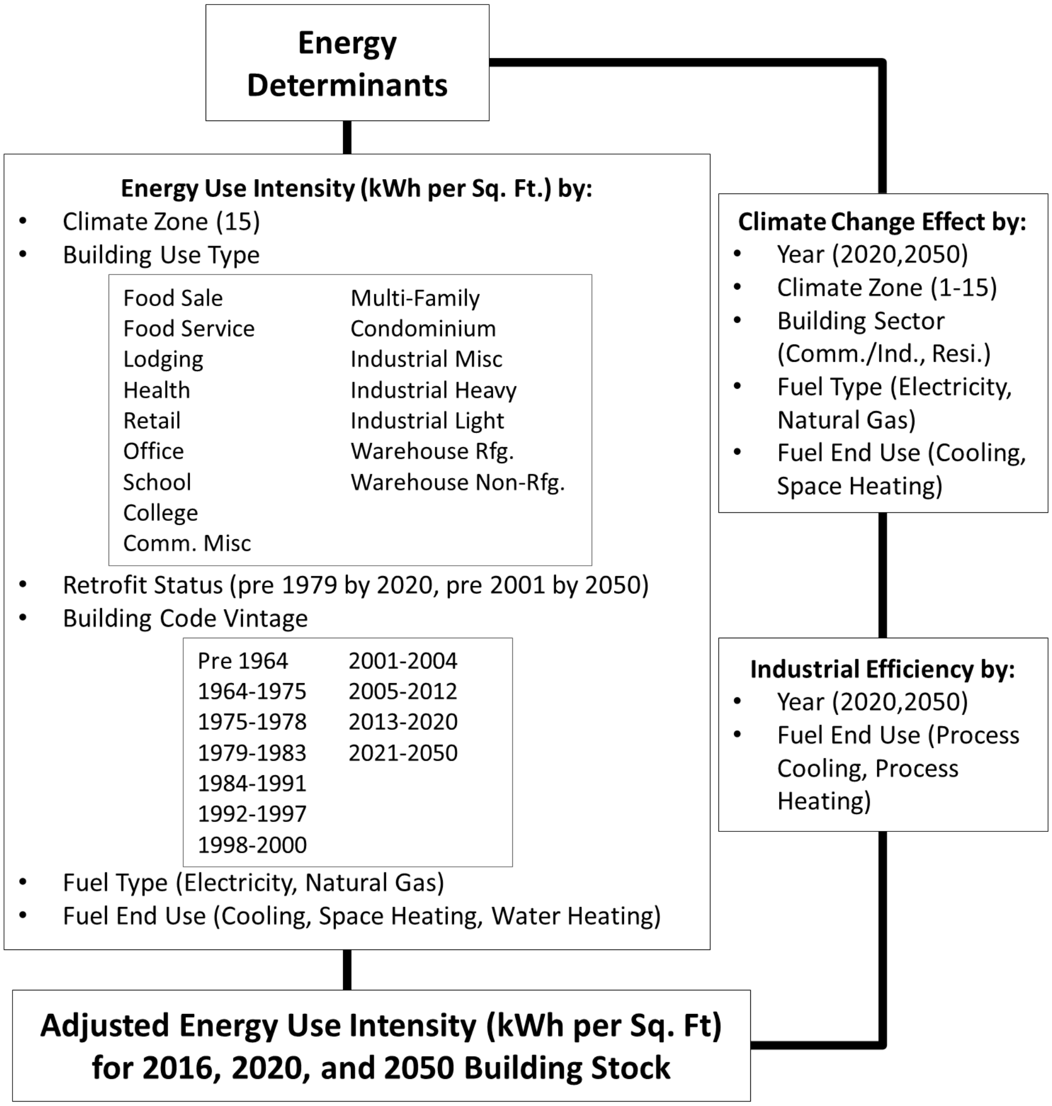
Table 21: Building Use Types are Matched with Parcel Types and Lifespans

Use Type	Parcel Building Description	Lifespan
Multi Family	Multiple family residential; Apartment; Timeshare	80
Condo	Condominium	80
Food Service	Restaurant	50
Food Sale	Mini mart; Grocery store	55
Lodging	Boarding house; Student housing; Hotel/Motel/Resort	53
Retail	Retail sale	50
Health	Hospital; Medical/Dental/Lab; Retirement home; Nursery	55
School	School; Daycare center	62
Office	Office; Shopping center; Bank; Government; Post office; Tax exempt	58
Comm Misc	Commercial unspecified	55
Misc	Mobile.Manufactured home; Automotive use; Laundromat; Veterinarian/Hosp; Miscellaneous; Recreational; Church; Cemetery/Mortuary	55
Industrial	Industrial unspecified	58
Industrial Heavy	Industrial heavy (e.g. food processing, milling)	
Industrial Light	Industrial light (e.g. printing, furniture)	
Warehouse	Warehouse	58
Refr. Warehouse	Refrigerated warehouse	58
College	College; University	70
Vacant	Vacant	55

An asterisk indicates county office codes.

Source: EIA 2017a,b.

Figure 8: Block Diagram of Energy Use Intensity (EUIs) Development for 2016, 2020, and 2050 Building Stocks



Source: Lawrence Berkeley National Laboratory

The CEUS database and the Energy Commission forecast inputs provide the highest disaggregation of EUIs in terms of building types and climate zones, and are both highly sited sources. On average, the CEUS EUIs are higher than the Energy Commission EUIs, and are not specific to building vintage. The EUIs from the Energy Commission reflect changes in energy intensity resulting from building codes updates from 1975 to 2013. In this analysis, EUI vintages from the California Energy Commission’s database are used to model commercial buildings and warehouses.

Energy use intensities for light, heavy, and miscellaneous industrial buildings are derived from the DOE Advanced Manufacturing Office (AMO) manufacturing energy and carbon footprints. These footprints, derived from the 2010 MECS database, report national electricity and fuel consumption (trillion BTUs) for process cooling, process heating, and facility HVAC end uses for industrial sectors. Enclosed floorspace per establishment and the total number of establishments for each industrial sector are collected from MECS to estimate total national floorspace. Energy consumption by end use is then divided by total floorspace to estimate

EUIs. It is assumed that 62.5% of electricity to HVAC goes to cooling, while 85.2% and 14.8% of natural gas to HVAC goes to space heating and cooling, respectively. These fractions are estimated from CBECS data on warehouse HVAC end uses. Values for the heavy industrial buildings category are estimated by summing floorspace weighted EUIs of industries identified as being "heavy" industrial (Breunig et al. 2018b). Energy end use for the miscellaneous industrial sector is used to represent both light industrial and miscellaneous industrial buildings. HVAC values are adjusted for climate zone impacts using the variation in warehouse EUIs among climate zones as a reference.

Consumption of natural gas for space and water heating and cooling, and of electricity for cooling in multi-family buildings is estimated using data from 2009 RECS. Average consumption per household in multi-family buildings with 5 or more units (households) is converted to consumption per floorspace using average household size data from RECS in that building type. Although units in a building are often different sizes, using an average floorspace for each unit in the building makes it possible to estimate energy consumption in parcels that only provide floorspace, and not unit number. Scaling factors are developed to adjust EUIs for climate impacts by assessing variations in space heating, cooling, and water heating in lodging use types in different climate zones.

3.3.2 Impact of Energy Efficiency

Parcels are assigned to zip codes and forecasting climate zones (FCZ), using a zipcode-FCZ key provided by the California Energy Commission; FCZ differ significantly from California Building Standards Climate Zones. Parcels are assigned building EUIs based on use type, a California Energy Commission forecasting climate zone, and build year. Buildings built between 2013 and 2020 are assigned the 2013 EUIs. The California Energy Commission periodically publishes forecasts of energy consumption in California, the most recent forecast going out to 2026. EUIs for each building type and climate zone are compared from 2005 to 2013, and the average annual rate of change is assumed to hold out to 2035, upon which EUIs are assumed to remain constant. This reflects a limit on the energy savings that can be achieved through improved building shells and equipment. It is assumed that that individual building systems with natural gas cooling equipment will be rare in the future; to reflect this assumption, all natural gas cooling is converted to electrical cooling by 2050.

To reflect energy retrofits, it is assumed that buildings built before 1975 are retrofitted by 2020 to 2013 code, and that buildings built before 2001 are retrofitted to 2013 code by 2050. This retrofit schedule is adjusted in the Sensitivity Analysis. It is assumed that efficiency between 2020 and 2050 in multifamily residential buildings improves at the same rate as lodging, which includes boarding houses, student housing, and hotels. Efficiency in HVAC systems in industrial buildings is assumed to improve at the same rate as warehouses. Industrial process and cooling efficiencies of 10% by 2020 and by 49% by 2050 are assumed based on a report by the DOE Advance Manufacturing Office on barriers to industrial energy efficiency.

Population growth in warmer regions and climate change will lead to the increase use of electricity to power air conditioners (A/C). This is predicted to lower load factors. The increased use of electricity for cooling will be a function of outside air temperature and building thermal efficiencies, and will occur in buildings where humans and animals require

A/C for thermal comfort and where there is heat-sensitive equipment like electronics. Increased electric demand could be offset by alternative sources of cooling such as waste-heat powered cooling. Xu et al. assess the impacts of climate change on building heating and cooling in California. They used general circulation model projections out to 2040, 2070, 2100 and downscaled outputs to sites for building cooling and heating simulations. Their assessment modeled the climate in California getting warmer and found that certain types of buildings were more sensitive than others, resulting in the aggregate energy consumption from buildings only slightly increasing. Xu et al. projected that electricity use for cooling will increase by 25- 50% over next 100 years in certain areas of California.

The California Energy Commission estimates net climate change impacts on electricity consumption for each planning area in 2026 for a number of climate scenarios, including a mid-case (1/2 degree change) and a high-case (3/4 degree change, used in the Sensitivity Analysis) (Kavalec et al. 2014; Kavalec et al. 2016). Total consumption is disaggregated into consumption for cooling end uses for the commercial and residential sectors. The Energy Commission's reports estimate that 50% of the increase in electricity consumption for cooling will come from the commercial sector. The impact of climate change on natural gas consumption is also estimated by natural gas planning area out to 2020. These projections are disaggregated into commercial and residential sector impacts, and space heating end uses. The study estimates that natural gas consumption for heating decreases, with 50% of the decrease coming from the residential sector, and 25 percent coming from the commercial sector. Assuming the rate of change for both electrical cooling and natural gas heating continues out to 2050, the total impact by planning area can then be determined. The impact at the climate zone level is assumed to be the same as the planning area it lies within. Changes in industrial buildings are assumed to be proportional to changes in commercial buildings.

3.4 District Energy Assessment

The 'break-even' point for cost per unit of supplied thermal energy for a district network option when compared with a base case – heat and hot water from gas boilers and cooling from high efficiency electric chillers supplied from the grid is estimated. This is necessary for assessing energy density thresholds required to support district energy networks. The method developed for this calculation is conducted for district heating and district cooling test cases as described.

The literature review conducted leading into this exercise consisted largely of European research and is therefore instructive in methodological terms, but not in clarifying cost-effectiveness in California. This method therefore incorporates California-specific inputs where relevant / possible and will be modified to reflect the development of ideas / changes to materials costs and energy prices.

For the purposes of assessing district network viability, the principle here is that thermal energy is available to use at the boundary of the assessed unit area (granularity is at the Census Block Group level), and that thermal energy supplied via a network and the value derived from it shall be the sole means of paying off the capital cost.

1. Test Cases
    a. District heat for heating and hot water (and heat for cooling utilizing existing on-site absorption chiller technology)
    b. District cooling (chilled water network with absorption unit(s) collocated with CHP)
2. Thermal Energy Supply Strategies and Pipe Sizing
    a. Sized for peak load at individual customer building connections

It is at the discretion of individual building owners and operators to operate dedicated back-up/ standby thermal plant independent of a district thermal supply, but that scenario is not accounted for in the analysis.

3. District energy scenarios
    a. Extension of existing heat / cooling networks (defined radius limit) to connect new and existing buildings nearby
    b. Development of new district systems for large-scale new developments
    c. Option B above, plus expansion of these new systems to connect existing buildings nearby

3.4.1 Network Model

The concept is based on using a network model analogue to determine a thermal energy density threshold, which can then be applied as a viability proxy. To accomplish this, the following are used: an average number of loads per unit-area (based on analysis of the qualifying census block groups (CBG)), an average unit-area size (based on the same CBG sample), and then identify the point at which the district network option becomes equal or less costly per unit thermal energy supplied than the base case.[1]

The key values in the model are therefore a) a base case cost of thermal energy, b) thermal load conditions that result in break-even for the DE case against the base case and, c) the thermal energy density that reflects the break-even point.

The model utilizes rules of thumb to synthesize a network geometry and estimate thermal density the breakeven point, according to key inputs, including:

- Geographical area for thermal energy supply (Unit: Km^2)
- No. of thermal energy customers per unit area
- Peak thermal supply (Units: kW)

[1] For heating and hot water, the base case assumes gas boilers with an average operating efficiency of 80% and a commercial gas price of $8.08 per 1,000 cubic feet. For cooling, the base case assumes high efficiency electric chillers with an average performance rating of 0.59 kW/ton and a commercial electricity price of $0.16 / kWh.

- Delta-T on the primary heat network, assuming low-temp hot water design, supply temps between 60-90°C (40°C assumed for district heating, 10°C assumed for district cooling, with sensitivities at 45°C and 12°C respectively).
- Load factor of ~19%, consistent with data from current systems
- Discount rate of 3.5%
- Electricity price for cooling and for DE electricity such as pumping (Current commercial electricity prices of $0.16/kWh)
- Fuel price (five-year average gas price of $8.08 per 1000 ft^3, translating to $0.008/kBTU or $0.034 / kWh)

This concept draws heavily from analysis completed by an IEA research group in 2005 (A comparison of Distributed CHP/DH with Large-scale CHP/DH) but employs a static calculation method (i.e. the geometry is not optimized according to reduction of pressure drop or flow rates, utilizing hydraulic analysis as the IEA work was) according to the key inputs identified above, and uses assumptions based on fundamental engineering principles. [2]

To synthesize the network geometry, there are several other key input assumptions:

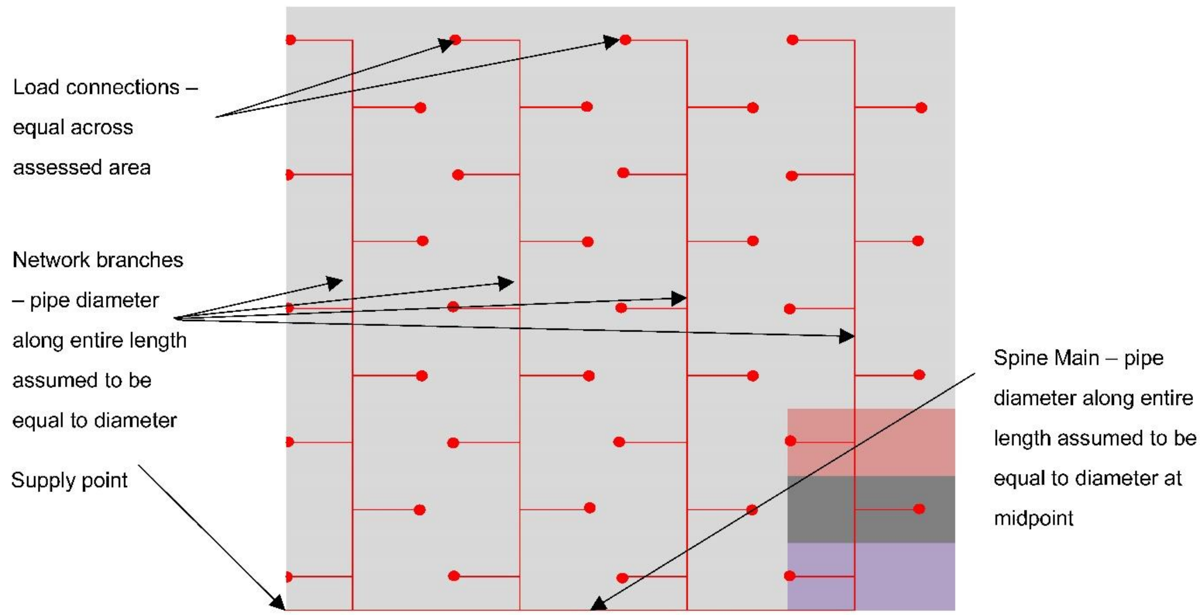
- Summing of participating building loads, then averaging and distributing the average load uniformly across all participating buildings.[3]
- Assuming an even spread of building loads across the assessment area via a simple formula and by assuming a square area as an analogue for each CBG area (i.e. an irregular polygonal area of assessment of 2 km^2 would be represented in the model as a square with a side length of 1.41 km).

Figure 9 illustrates how the model arranges the even distribution of loads within an area of assessment (block colors in bottom right of the figure indicate equal areas covered per load node).

[2] For the IEA analysis, the network geometry is optimized according to reduction of pressure drop, flow rates, and pumping energy, using hydraulic modeling software and analysis.

[3] It is proposed that as the relationship between pipe size and pipe cost is somewhat linear, average size will suffice for our purposes.

Figure 9: Notional Network Layout



Source: Lawrence Berkeley National Laboratory

The model is intended for generalized scenarios only – it is not representation of any site-specific cases (which will inevitably have uneven distributions of loads in terms of geography and magnitude) and is not optimized for pressure drop of flow rate considerations. Such analysis would require iterative hydraulic modeling, which is not practical within the scope of this project.

The model generates pipe network diameters for each part of the network and pipe lengths per diameter. Referring to cost inputs for pipe sizes per unit length, it is possible to determine a full network cost for the assessed area.[4]

It is important to note which capital items are being included in network cost estimates, and which are left out.[5] From the point of view of identifying the minimum hurdle for a viable network, the team proposed that, in principle, thermal energy may be zero cost at the point of supply. In adopting that position, costs for generation assets, supporting equipment, fuel or items have not been included beyond the thermal network itself - which is defined as all network assets included in the transport and distribution of the point of supply and the customer load – in this stage of the analysis.[6] Network costs therefore include thermal transfer stations (heat exchangers), pumps and pipes (buried cost). Costs for pumping, are also

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[4] For the purposes of estimating cost, each branch line is assumed to be a diameter sufficient to supply half the total capacity on the branch (i.e. the peak load measured at its midpoint) along its full length, and similarly the spine main is assumed to be a diameter capable of meeting the peak of half the loads on the spine, again, measured at its midpoint.

[5] Items not part of the network are nevertheless included in the TEA analysis.

[6] The full systems cost including capital costs of energy generation assets, operation and maintenance of generation plant are included in the Techno-Economic Analysis outlined in Section 5 of this report.

included, using the commercial rate per unit of electricity identified above, and based on peak load and consumption, and are amortized over the lifetime of the network (30 years).

This demarcation of the network described also reflects a broader separation of generation, distribution, and customer assets that is relatively common for such systems – it reflects both a prevailing technical standard for large scale systems whereby hydraulic separation allows greater operating flexibility and contractual boundaries of responsibility, where different entities may operate distinct parts of the overall system as discreet units.

Table 22: Capital and Operating Cost Model Inputs

Cost Type and Description	Input Assumption
District network	Network length determined by CBG area and number of loads, diameter of pipes determined by total connected peak load, distributed uniformly across building node connections, pipe costs per unit length according to diameter and cost inputs from Source: Lawrence Berkeley National Laboratory Table 23 below
Thermal energy transfer stations	Two thermal exchange (TX) unites, each sized to 60% of design peak load, with capacity and associated costs indicated in Table 3 below.[7]
Balance of network plant / equipment	5% of combined capital cost of thermal network and TX units
Design, engineering and project management	10% of all network / plant / equipment capital costs
Misc project costs	13% of all project and capital costs (10% contingency, 3% profit)

Source: Lawrence Berkeley National Laboratory

[7] TX costs require updating – quoted figures are in 2009 GBP

Table 23: Other Model Inputs and Calculations

Item Description	Input Assumption
Load Factor (Supplied Thermal Energy/Peak Connected Load*8760)	15%
ΔT heating	40-45°C
ΔT cooling	10-12°C
Network static pressure	10 bar
Pump efficiency	60%
Pumping load factor (equivalent to system load factor)	Same as system load factor
Pump head	((Thermal demand / ΔT) / SHC H_20) * (ΔP / Pump Eff.)
Pumping energy (non-optimized)	Pump head * load factor * 8760 + pressure loss energy
Electricity rate (for pumping)	$0.16 / kWh
Thermal losses	13% of network supplied energy (Ahlgren 2013; Borovsky and Huther 2012)
Pressure losses	10 kWh/ MWh energy delivered, translated into additional energy costs using electricity rate above (Ahlgren 2013)
Service and maintenance costs	1% of total investment cost per year (Ahlgren 2013)
Heating BAU	Central gas boilers, annual efficiency of 80% (2020).
Cooling BAU	Centrifugal water-cooled chiller plant, annual operating performance of 0.59 kW/ton, or overall plant CoP of 6 (2020) increasing to 0.44 kW/ton, or overall plant CoP of 8 in 2050.

Source: Lawrence Berkeley National Laboratory

Outputs from the model in terms of pipe length, diameter and cost, thermal transfer equipment costs and engineering plus annual operating costs are included in a discounted cash flow to generate an overall net present cost for a network for the average census block group characteristics.

From that, annual annuity is calculated using a nominal 3.5% discount rate, assuming the network pays for itself over a 30-year lifetime. Dividing the annuity by the volume annual energy supplied provides an estimate for the cost per unit of thermal energy.

Table 24: Network Cost Inputs

Nominal Diameter	Pipe Diameter (m)	Cost ($k/m) – Urban	Cost ($k/m) – New Site
DN 25	29.7	0.42	0.33
DN 32	37.8	0.45	0.36
DN 40	43.7	0.47	0.38
DN 50	55.7	0.53	0.43
DN 65	70.9	0.57	0.47
DN 80	83.1	0.66	0.54
DN 100	107.9	0.81	0.69
DN 125	132.5	0.98	0.85
DN 150	160.3	1.18	1.02
DN 200	210.1	1.40	1.22
DN 250	250	1.88	1.68
DN 300	300	2.25	2.01
DN 400	400	3.00	2.69
DN 500	500	3.76	3.36
DN 600	600	4.51	4.03

Source: Nussbaumer and Thalmann 2016.

Table 25: TX Capital Costs

Capacity (kW)	Cost
37	1,691
49	2,230
81	3,675
98	4,439
186	8,355
200	8,971
250	11,161
500	21,786
800	33,829
1000	41,429
1500	58,929
2000	74,286
3000	98,571
4000	114,286

Source: Cost data provided by project Technical Advisory Committee member, GLHN.

3.4.2 District Energy Market

The economics and viability of future DES systems must be evaluated in the context of whether they are an extension to an existing system, a brand new district network in a large, mixed use site, or a brand new district network in existing urban environments. All three types of networks can be identified using outputs of the building dynamics model.

A second method is developed for this task to characterize the building types and building sizes for new district network projects throughout the state. From a review of mixed use development projects, small, medium, and large archetypes are developed. These archetypes are then utilized with projected changes in floorspace to get an understanding of the potential number of district network projects that could be developed.

3.4.2.1 Existing District Energy Systems

The first step is to determine the cohort of existing systems, as these are likely to form the basis of expansion of district systems in the State. Data on existing district energy systems (location, size, thermal service type, presence of CHP and prime mover technology) was acquired through correspondence with Laxmi Rao, Director of the International District Energy Association (IDEA). The list of district systems is not published in this report as it includes some sensitive information.

3.4.2.2 Technical, Economic and Market Potential for Expansion of Existing Systems

A number of screens are used for determining technical, economic, and market potential of Census Block Groups (CBG) for the expansion and development of existing DES systems.

Technical potential is the total feasible potential for new connections near to an existing district system, ignoring cost barriers. The team estimated this assuming a set of building prototypes (as discussed in previous sections) and a size cutoff of 50,000 ft^2. This cutoff reflects the average size of buildings with central heating and / or cooling systems, for which connection to district thermal systems is most likely.[8]

Economic potential is estimated using the heating density (1.0805 kWh/ft2 heat consumption) or cooling density (1.74 kWh/ft2 cooling consumption) determined within the network model as cutoffs for viability in the analysis of CBGs. These cutoffs reflect the average number of connections (estimated in this analysis as parcels with heating or cooling consumption) and the average CBG size as inputs to the network analysis model, described above.

Market potential is estimated based on the suitability of individual building connections and diversity of building types within clusters of potential connections. In this context, building thermal energy load profiles are the key consideration, in that they denote the degree to which connecting to a network system makes business sense to the district system operator.[9]

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[8] In principle, thermal plant in the building could simply be replaced with heat exchangers that would provide the same service.

[9] It is assumed that in general building owner / operators are persuaded to connect by competitive energy supply rates and the opportunity to reduce significant plant maintenance costs from balance sheets.

This relates to the degree to which such connections may further contribute to the thermal energy baseload on the system. In this context, the team refers directly to work done by the EPA Smart Growth initiative that rates building types according to their baseload contribution (Office of Sustainable Communities and Smart Growth Program 2015). Baseload scores from the EPA Smart Growth Report are used to rate building use types here. From the perspective of total new baseload and building load diversity, the team assumed that a cumulative score of 25 is determined to be a suitable screen for an individual CBG. A final screen excluding buildings with stories less than 4 is applied in 2050 to exclude buildings that are likely candidates for net-zero energy building status (based on rule-of-thumb ratio of solar rooftop potential and energy consumption). Finally, only CBGs within 2 miles of exiting DES are evaluated.

Table 26: Building Use Type Heating and Cooling Load Scores for Viability in District Systems

Type	Cooling Load	Heating Load
Health	5	4
Office	4	0
Rf Wrhs	5	0
College	3	3
School	3	3
Food Sale	3	0
Retail	3	3
Food Service	4	0
Lodging	0	5
Multi-Family	0	5
Condo	0	5

Source: Adapted from the EPA Smart Growth Report (Office of Sustainable Communities and Smart Growth Program 2015).

3.5 GIS Mapping of Priority Areas

Energy EUIs are assigned to parcels based on building use type, climate zone, and building vintage. It is assumed that vacant buildings have zero energy consumption. Active building floorspace expected in 2016, 2020, and 2050 in each parcel is multiplied with assigned EUIs for space heating, water heating, cooling, process heating, and process cooling. Total heating and total cooling energy consumption are calculated for each parcel.

For the analysis of district energy system potential, it is useful to assess heating and cooling densities at district levels like the census block group. A floorspace cutoff of 50000 ft^2 is used, reflecting a rule of thumb that buildings of this size or larger tend to have centralized thermal energy systems and are therefore realistic candidates for district energy system connection.

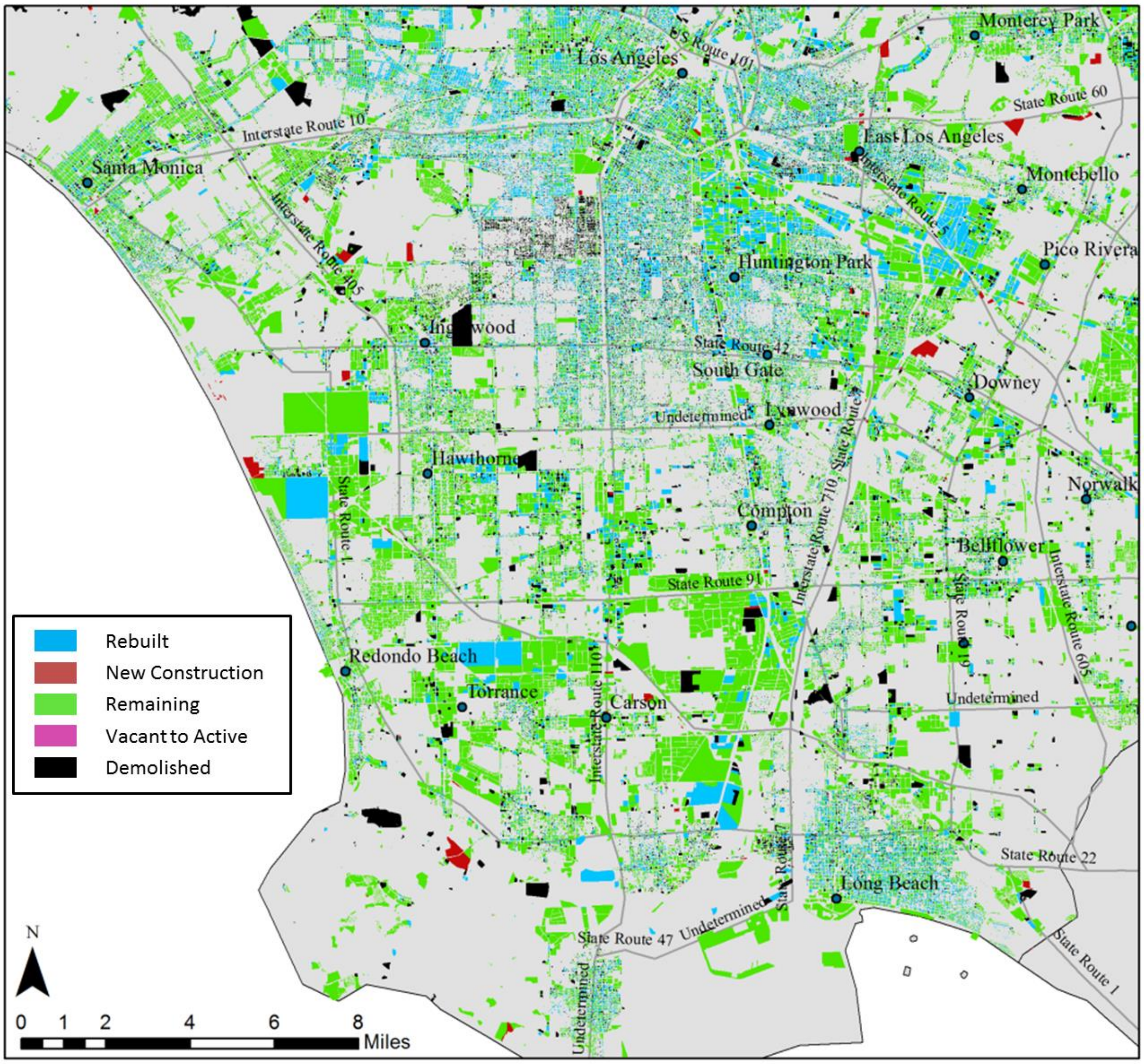
Parcel shapefiles with heating and cooling consumption are assigned the CBG identifier of the CBG that contains the parcel centroid. Total heat and cooling consumption is then divided by the CBG area to determine heating and cooling densities [kWh/ft^2].

Between 2016 and 2050, active residential floorspace is expected to increase 16 percent statewide, while active industrial floorspace increased by 23 percent and active commercial floorspace increases by 47 percent. Large growth in active commercial floorspace reflects expected increases in education, health, miscellaneous commercial, and offices by 2050. Statewide, food sales and retail experiences the smallest growth of commercial building types, with negative growth expected in a number of counties. A little over 5 billion ft^2 of floorspace (51%) is allocated to building rebuilds by 2050. Roughly 0.1 billion ft^2 of floorspace (1%) is construction in open lots, 5 million ft^2 (0.05%) is allocated to vacant parcels, and 2.6 million ft2 (0.03%) is new development allocated to unbroken ground by 2050. Assuming a cap of 400 percent on growth in a given parcel, 76 percent and 21 percent of counties required some additional floorspace allocations to parcels with open lot areas and vacant parcels, respectively, beyond rebuilds of demolished buildings. Miscellaneous buildings, offices, and condos made up the majority of floorspace allocated to open lot areas and vacant parcels statewide. The contribution of remaining buildings, rebuilds, activated vacant parcels, and construction on open lots to the 2020 building stock are show for the Los Angeles metropolitan area in Figure 10. Seventeen counties had building types where active floorspace (51 million ft^2) became vacant, the majority of which is office buildings. Negligible (240,000 ft2) floorspace went from active to vacant between 2020 and 2050.

In the 2016 building stock, buildings consume a total of 53,700 GWh/y for heat and 155,100 GWh/y for cooling. Commercial buildings contribute 31 percent to heating and 60 percent to cooling, while multifamily residential buildings contribute 45 percent to heating and 8 percent to cooling. Industrial buildings contribute 9 percent to heating, and 15 percent to cooling. Miscellaneous buildings account for ~16 percent of energy consumption, while warehouses account for ~2 percent.

In 2020, buildings consumed 46,100 GWh/y for heating and 101,000 GWh/y for cooling, with a decrease in contribution from commercial buildings relative to residential and industrial buildings. Natural gas fueled space heating accounts for 67 percent of all heating energy consumption. Electrical cooling accounts for 69 percent of all cooling energy consumption. In 2050, buildings consume 52,600 GWh/y for heating and 124,000 GWh/y for cooling, with ~approximately 44 percent of energy consumption coming from buildings remaining from 2020, and 55 percent coming from buildings rebuilt since 2020. Large buildings with floorspace of 50,000 ft^2 or larger in 2050 contribute 56 percent of heating consumption and 68 percent of cooling consumption. These changes reflect both the distribution of buildings throughout the state, as well as the sector level impact of building standards on energy efficiency. There was ~ 19.5 million ft^2 of new development (unallocated to parcels) in 2020 and 2.6 million ft^2 of new development in 2050, the majority of which is college and miscellaneous building types.

Figure 10: 2020 Building Stock in Downtown Los Angeles Area Displayed at the Parcel-Level



Color code indicates the dynamics likely to occur by 2020.

Source: Major roads shapefile from Ventyx 2012 dataset.

Accounting for only large buildings (50,000 ft^2 or larger). In 2050, heating consumption densities ranged from zero to 403 kWh/ft^2 Census Block Group (CBG) area while cooling consumption densities ranged from zero to 296 kWh/ft^2 Census Block Group (CBG) area. While the densest heating and cooling consumption occurred in downtown San Francisco, Los Angeles has the largest number of CBG with densities.

Despite large variations in size, CBGs are a reasonable approximation of district sizes, and are useful geometries for screening for potential for district energy systems (DES). In 2012, the IDEA reported a heat density threshold of 0.94 kWh/ft^2 is necessary for a viable DES project. This value is likely to be low for California, and while detailed estimations of area specific material and construction costs are needed to estimate cost-effective heat density thresholds, this value makes for a conservative initial benchmark. In 2050, 24% of CBG that contain large buildings with energy consumption would meet this heating density threshold and 13% of CBG would meet a cooling density threshold of 0.94 kWh/ft^2.

3.6 Sensitivity Analysis

Key model inputs such as building life span (Run 1), rebuild size limits (Run 2), county level growth (Run 3), climate change impacts to EUIs (Run 4), and retrofit schedules (Run 5) are adjusted in a sensitivity analysis (Breunig et al. 2018).

For Run 1, increasing the lifespan of buildings by 40 years resulted in a 4 percent increase in heating and 9 percent increase in cooling consumption at the state level, and significant changes to the proportion of energy consumed by different counties and building types. Heating and cooling consumption in 2050 from rebuilds decreased by 72 and 74 percent, while heating and cooling from remaining buildings increased by 57 and 75 percent. In the base run, floorspace allocated to open lots and vacant buildings contributed roughly 1 percent to energy consumption, while in Run 1, filled lots contributed 9 percent and vacant buildings contributed 1 percent. Heating consumption densities ranged from zero to 364 kWh/ft^2 Census Block Group (CBG) area while cooling consumption densities ranged from zero to 121 kWh/ft^2 Census Block Group (CBG) area. In 2050, 9.6% of CBGs that contain buildings with energy consumption would meet this heating density threshold and 19.5% of CBG would meet a cooling density threshold of 0.94 kWh/ft^2. Effectively, heating and cooling is less densified than the base scenario, as existing buildings last longer, and new construction is required to meet expected growth in floorspace.

For Run 2, changing the cap on 2020 rebuild size resulted in negligible changes in total energy consumption at the state level and in the contributions of counties and building types. Changing the cap on 2020 rebuild size did result in a 4% increase in heating consumption and 8% increase in cooling consumption in 2020 rebuilds compared with the base scenario, while heating consumption decreased 32 percent and cooling consumption decreased 41 percent in the floorspace allocated to vacant buildings and open lots, compared to the base scenario. However, the energy consumption associated with floorspace allocated to rebuilds, vacant buildings, and open lots between 2020 and 2050 does not differ from the base scenario. Heating and cooling consumption densities are the same as the base scenario. In 2050, 13.8% of CBGs that contain buildings with energy consumption would meet this heating density threshold and 25.2% of CBG would meet a cooling density threshold of 0.94 kWh/ft^2. Effectively, heating and cooling spatial distribution is similar to that the base scenario.

For Run 3, substituting the state average growth factor for the base scenario assumption of steady state (factor of 1) for building types in counties without economic sector projections increased statewide heating and cooling consumption by 1 percent. This is not to say that major changes did not occur at the county level, only that changes occurred in counties with relatively small energy consumption, and not all changes were positive. For example, energy consumption increased by 58 percent in Trinity Co. and 46 percent in Humboldt Co., while ten counties experienced decreases in total energy consumption.

For Run 4, substituting the high scenario for the mid climate change scenario adopted by the Energy Commission resulted in increased cooling demand and decreased heating demand. By 2050 cooling increased by 3 percent and heating decreased by 11 percent, with a statewide reduction in energy consumption of 1 percent. Impacts from climate change on heating consumption varied substantially among counties, with reductions reaching as much as 75 percent in Orange Co. and 43 percent in Imperial Co. Impacts on cooling consumption had a smaller range (2-4 percent), reflecting the similar changes in electrical cooling predicted for service areas (Kavalec et al. 2014; Kavalec et al. 2016). Without any climate change scenario, total energy consumption for cooling is 9 percent lower statewide, and heating is 7 percent higher. Cooling consumption was 14 percent lower in some counties like Sacramento, while heating consumption was dramatically higher in counties like Orange, Imperial, and Los Angeles.

For Run 5, running the model without any retrofits of existing buildings increased cooling consumption by 1 percent and heating consumption by 4 percent. San Joaquin Co., Madera Co., Yolo Co., and Solano Co. revealed higher sensitivity to the retrofit schedules, suggesting that a larger fraction of buildings in these counties with high energy consumption are going to remain out to 2050. In a second run, assuming a greater fraction of the existing 2016 building stock is retrofitted, compared to the EUI that would be assigned based on the effective construction year, had negligible effects on energy consumption by 2050. This is an expected result as the retrofit schedule used in the base scenario for 2020 is already optimistic.

3.7 District Energy in New Construction

The potential for district energy in new construction is considered to be significantly greater in new construction than the existing urban environment at this time. This reflects the fact that implementation costs for new systems are likely to be considerably cheaper than for retrofits - installing systems in locations with little to no existing infrastructure does not present the same risks or obstacles as installing new pipe infrastructure in busy streets. In principle, finding appropriate locations and space for large central plant is also likely to be less of a challenge.

3.7.1 Characterizing Mixed-Use Development Sites

Determining potential for district networks in new construction is a challenge for the simple reason that there are no confirmed building energy loads as inputs to analysis – there are always uncertainties associated with development schedules and final buildout characteristics.

Initially, the project team reviewed online planning portals for large urban centers (ten largest cities in California) in an attempt to determine anticipated new construction at specific locations. It was anticipated that this approach could further leverage use of the network model in that not only could potential for district networks within the boundary of new development sites be determined, but it would be possible to explore the extent to which new development at as a route for supply of zero-carbon heat and cooling into existing buildings nearby. Review of these resources was a largely fruitless exercise in that they were largely devoid of information or relevant detail.

LBNL then conducted an online search for new-build mixed use development in California, the goal of which was to identify at least 3 mixed use development sites, in the counties that host the 10 largest cities in the State (a minimum of 30 projects in total). The credible information that was available was from at least two sources for each site, for 29 sites, in nine counties.

From the project data collected, many (~50%) of the identified mixed-use sites consisted of a combination of office and residential, but the data set as a whole had a residential skew. To negate this skew carrying into the data results as far as possible, the team grouped projects into quartiles using gross floor area of commercial offices. The quartiles was characterized as follows:

- Quartile 1 – 'Small' Projects
- Quartiles 2 & 3 – 'Medium' Projects
- Quartile 4 – 'Large' Projects

For each quartile, the intra-quartile average floor space for each of the key building types was calculated, and assumed that this average was an accurate representation of small, medium and large development sites respectively. For the purposes of the analysis, the (conservative) position is that that in general, only large projects provide the load density and magnitude to support of large-scale thermal networks. As such, the 'average' large development site characteristics in terms of building floor area were used in determining thermal load for the CHP potential assessment. The same site characteristics are assumed for the five climate zones with assumed large-scale development to occur.

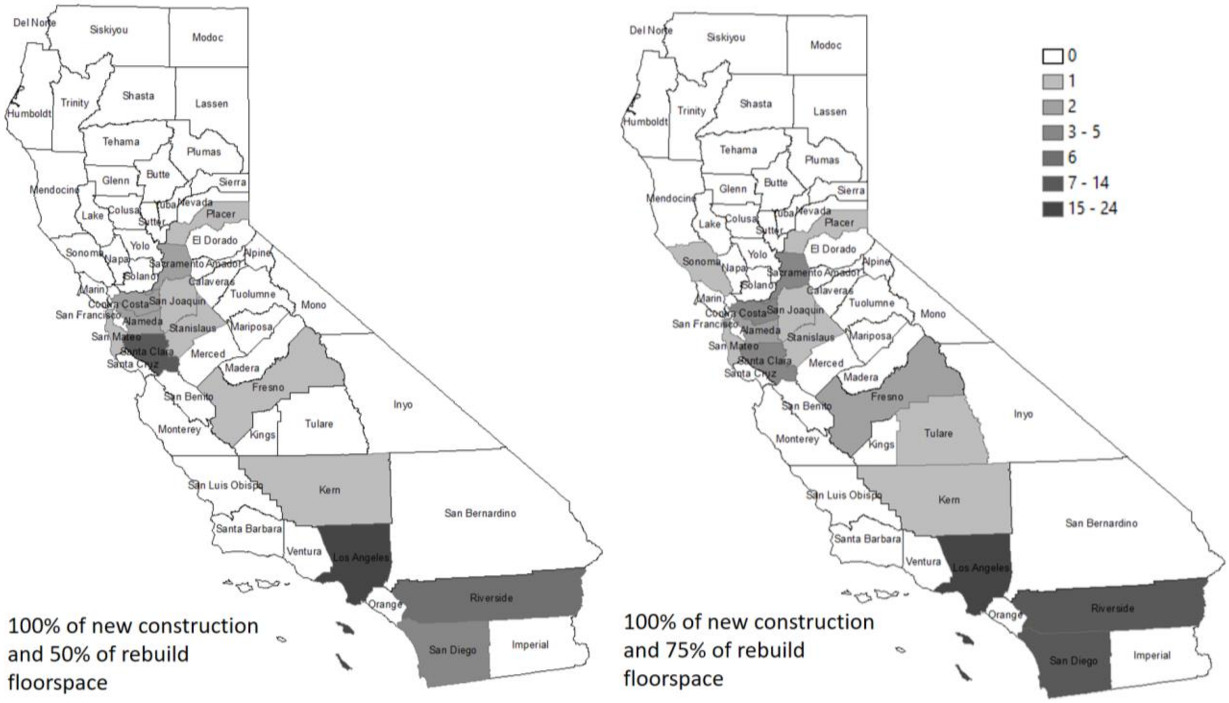
Table 27: Mixed Use Site Characteristics – Floor Area (ft^2)

	Residential	Hotel	Retail	Office
Small	202,000	43,700	9,900	300,800
Medium	1,455,457	119,300	225,400	889,300
Large	5,321,375	105,400	785,600	3,475,000

Source: Lawrence Berkeley National Laboratory

The main disadvantage of this approach is that while it is possible to propose the nature of development sites, it is not possible to confirm specific locations at which development will take place. As a result, the analysis cannot suggest what potential exists beyond the boundary of the new development site. Using outputs from Run0 of the building stock turnover model, and assuming 100% of new construction and 50% of floorspace allocated to rebuilds in each county can go towards MUD, the team found 54 sets of MUD statewide are possible (Figure 11). This increases to 63 MUD when 75% of floorspace allocated to rebuilds becomes available and decreases to three MUD when rebuild floorspace cannot be allocated to MUD. Furthermore, the team derived a low of 26 MUD and high of 100 MUD when assuming quartile values for archetype floor space, indicating the challenge of using this mixed floorspace-driven approach and identifying areas that have growth in four building types that meet the ideal ratio.

Figure 11: Demonstrative Estimation of New Mixed Use Developments by County



Source: Lawrence Berkeley National Laboratory

3.7.2 Mixed Use Development Sites – Thermal Load Conditions

The results of characterizing large mixed-use developments according to the method described above are summarized in Table 28 and the data that reflects these results comprise the key data input to the CHP model described in more detail.

Table 28: Thermal Load Conditions at Mixed Use Sites, by Climate Zone

CA Climate Zone	Peak – Space Heating and Hot Water (MW)	Peak – Space Cooling (MW)	Consumption – Space Heating and Hot Water (MWh)	Consumption – Space Cooling (MWh)
CZ 5 (Bay Area)	32.4	13.4	53,914	25,585
CZ 2 & 6 (North Central Valley)	36.2	27.1	60,215	51,851
CZ 3 (Central Valley)	31.7	40.9	52,785	78,256
CZ 8,9,11 & 12 (Los Angeles)	30.4	34.5	50,590	66,038
CZ 13 (San Diego)	34.7	20.3	57,822	38,838

Source: Lawrence Berkeley National Laboratory

For a robust analysis of the potential for district networks and CHP, outputs from the mixed-use development site characterization were used, in terms of building types, building areas and total site area as key inputs. Climate and building performance variables were included, so that CHP capacity proposed for all projects might appropriately reflect the expected geographic distribution of those projects (according to expected population and employment growth).

This has been accomplished by developing a simple CHP model, based on energy load profiles for heating and cooling for the five main climate zones in California and the team expects to see large, mixed-use development sites in the next 30 years or so. Using the load profiles as the main data input, and by varying the user inputs to the CHP model, it is possible to identify appropriate CHP capacity for these large developments in the five separate climate zones. The sum of all these installations together represents the CHP capacity that could be supported by mixed use development sites.

For viable CHP technologies, internal combustion gas engine (ICE) and fuel cell technologies as those appropriate due to their applicability for the scale in question, their ability to use biogas fuels and their compatibility with district systems comprising non-industrial customers, including the ability to modulate thermal output to match load conditions. Technology summaries of CHP options can be found in Section 4.5.2.

3.7.3 Test Cases and Brief Technical Summary

The technical details pertaining to each case are listed in Table 29.

3.7.4 CHP Model Summary

The basic principle of the analysis is to utilize building thermal load profiles as the key variable input data, and confirm appropriate sizes of CHP units according to the operating characteristics of different prime mover technologies and proposed operating strategies.

Within the model, it is possible to determine operations of CHP at hourly increments according to installed capacity, outputting key information such as number of annual operating hours, percentage of thermal load met (via thermal output and / or CHP electricity for cooling), amount of back-up thermal energy required, total power generation, thermal storage charging, whether all thermal generation was useable, etc.

This framework supports an 'optimization' of CHP unit size and total installed capacity, according to a target number of annual operating hours, with all associated outputs of the model reflecting the selected plant capacity and characteristics utilized in the techno-economic analysis, the results of which are contained in Section 5 of this report.

We have assumed here that an operating capacity that results in 5,000 annual operating hours is appropriate, and possibly conservative, given the high level of the modeling. The structure of the model supports sensitivity analysis on target annual operating hours, and other characteristics.

Table 29: Case Descriptions

	Spark-Ignition Gas Engine CHP Case	Fuel Cell (Solid Oxide or Molten Carbonate) Case
Electrical Efficiency (LHV)	40%	42.5%
Thermal Efficiency (LHV)	38%	39.3%
Low Grade Heat Fraction	55%	0%
High Grade Heat Fraction	45%	100%
Heating	Low-temperature hot water at 80-90°C, 40°C ΔT, heat exchange from engine jacket, lubrication oil, cooling water circuits (low grade heat) year round Low-temperature hot water at 80-90°C, 40°C ΔT, heat exchange from engine exhaust (high grade heat) from October 1 – March 31 Back-up heat supplied via natural gas-fired boiler	Low-temperature hot water at 80-90°C, 40°C ΔT, heat exchange from reformer and stack subsystem heat recovery and unit exhaust gases (all high grade heat) from October 1 – March 31 Back-up heat supplied via natural gas-fired boiler
Cooling	Chilled water at 17-18°C supply, 10°C ΔT, heat exchange from engine exhaust (high grade heat) to dual effect absorption chiller from April 1 – September 30 Back-up cooling supplied via water-cooled electric chillers, supplied with renewable CHP electricity or from the grid	Chilled water at 17-18°C supply, 10°C ΔT, heat exchange from reformer and stack subsystem heat recovery and unit engine exhaust (high grade heat) to dual effect absorption chiller from April 1 – September 30 Back-up cooling supplied via water-cooled electric chillers, supplied with renewable CHP electricity or from the grid

Sources: Combined Heat and Power Partnership 2015a,b; Haseli 2018.

3.7.4.1 Model Framework and Assumptions

The model uses 8760 thermal load profile data generated by Department of Energy (DOE) reference models for specific climate zones / regions in California – these represent areas of concentrated population and employment growth over the next 30 years or so and are therefore the regions in which large-scale mixed-use development is expected. The data were accessed from the U.S. DOE Open Data Catalog, last updated in 2013 (OpenEI). These models are widely referenced, created within a consistent framework and did not place additional resource burdens on the project as they are publicly available.

The thermal load profiles for building types present in the 'average' large mixed use development site characterization were applied to the appropriate square footage and the EUI for that building type to generate an overall thermal load profile for 1) heating and hot water, and 2) cooling, to generate load profile inputs for the entire new development site for heating and hot water (profile #1) and cooling (profile #2). These load profiles are factored up from the building models to reflect the floorspace of each of the principal building types assumed for a 'large' site, and to reflect the expected EUIs at year 2035 (midway between the time horizons of 2020 and 2050), projected by the California Energy Commission.

Inputs for CHP size, modulation / turndown capability, heating and cooling seasons and heat-to-power ratio result in an energy balance (excluding non-cooling electrical load) for the site load condition, indicating what quantum and proportion of heating, hot water and cooling can be met via zero-carbon heat, zero-carbon electricity and / or back-up sources. The more detailed model assumptions are outlined below.

Key Model Guiding Principles and Assumptions

- Comprises analysis of ICE and fuel cell technology. It is assumed that combustion/steam turbine and gas turbine technologies are too large in capacity for what is being considered here. Other technologies may be appropriate (microturbines, sterling engines, ORC) but permutations are limited so have included one mature/ transition technology and one still in development which shows promise for the foreseeable future.
- For gas engine applications, low- and high-grade heat meet heating load only in winter (Oct-March), in summer, low-grade heat is reserved for meeting heating and hot water load, high grade for cooling, on the basis of a 55:45 low grade: high grade ratio. This is on the basis that low-grade heat is not suitable for dual-effect absorption chillers.
- For fuel cells, as all heat produced is high grade, this is assumed to be more flexible - all heat is assumed to meet heat load in winter and meet cooling load in summer. Any capability to divert thermal energy outside of the priority season service (provide heating in the summer) is not included.
- Accounting for all criteria above, all operating hours are at full capacity output, in that the thermal energy generated either goes to load or thermal storage. As a result part load operations are not included.
- For absorption cooling, the absorption units capacity are assumed to match with the high grade heat output of the CHP units supplying them.

- CHP units sized according to achieving approximately 5000 full load operating hours per year (13.7 hours per day average) on average for the 3 units.[10]
- Priority use for electricity generated is to supply electric chillers, which are assumed to also provide chilled water into district cooling network. Thereafter, all electricity is assumed for use on site.
- Thermal losses on district networks are a constant proportion of load.
- There are a range of possibilities to meet the thermal energy shortfall – this is covered in the techno-economic analysis of the project in Chapter 5

3.7.4.2 CHP Model Outputs

The outputs of the CHP model for individual sites within each of the 5 climate zones modeled can be seen in Table 30 and Table 31.

Table 30: Spark-Ignition Gas Engine - CHP Characteristic

CA Climate Zone	CHP Unit Size (kWth)	CHP Installed Capacity (kWth)	CHP Operating Hours	Heat Load Met by CHP Heat	Cooling Load Met by CHP (Thermal)	Cooling Load Met by CHP (Thermal and Electrical)
CZ 5 (Bay Area)	4090	12273	5039	90%	60%	96%
CZ 2 & 6 (North Central Valley)	2273	6818	6287	56%	21%	96%
CZ 3 (Central Valley)	1955	5864	6532	56%	13%	96%
CZ 8,9,11 & 12 (Los Angeles)	2455	7364	5749	62%	19%	98%
CZ 13 (San Diego)	2455	7364	5525	53%	31%	99%

Source: Lawrence Berkeley National Laboratory

This summary reflects building thermal load data inputs, and the assumptions underlying formulas in the model outlined above. The outputs are a high-level summary of the more granular data from the model, that reflects the overall energy balance for each climate zone site, from which environmental performance data is extracted for the purposes of the Lifecycle Analysis (LCA) and equipment schedules and energy performance data is utilized in the Techno-Economic Analysis (TEA), both presented in Section 5 of this report. Additionally, greenhouse gas emissions from CHP are presented in the Introduction in Figure 1. The results as they relate to total potential for district systems in new development sites are presented in the following section.

[10] Hours of operation are a proxy for cost effectiveness in this context, in the sense that for a higher number of operating hours the return on investment is correspondingly higher.

Table 31: Fuel Cell - CHP Characteristics

CA Climate Zone	CHP Unit Size (kWth)	CHP Installed Capacity (kWth)	CHP Operating Hours	Heat Load Met by CHP Heat	Cooling Load Met (Thermal)	Cooling Load Met by CHP (Thermal and Electrical)
CZ 5 (Bay Area)	2900	8700	5037	49%	77%	99%
CZ 2 & 6 (North Central Valley)	4950	14850	5004	57%	89%	97%
CZ 3 (Central Valley)	5700	17100	5000	59%	80%	95%
CZ 8,9,11 & 12 (Los Angeles)	3750	11250	5010	46%	58%	98%
CZ 13 (San Diego)	2600	7800	5030	31%	63%	98%

Source: Lawrence Berkeley National Laboratory

3.8 Potential for District Network Expansion or Replacement

Screening of the building stock and future energy consumption allowed the project team to determine the following breakdown for district networks:

- Existing CHP DES now supplied with pipeline injected biogas for credits (49 systems)
- Existing CHP DES with a new plant but no expansion (49 systems)
- Existing CHP DES with a new plant and expansion (6 systems with potential for expansion: 43 systems that could get a new plant but no expansion)
- Existing DES without CHP with new plant of same size (17 systems)
- Existing DES without CHP with new plant and network expansion (4 systems with potential for expansion: 13 systems that could get a new plant but no expansion)
- Existing DES without CHP and with only hot or cold water (2 chilled water systems near cooling growth that might suggest potential for development)

These results are based on DES with locations falling in a census block group (CBG) that meets either cooling, heating, or both cooling and heating thresholds. Additional market, technical, and economic screens are presented in section 3.4 of this Chapter, and further reduce the potential for district network development at existing DES. Section 3.5 of this chapter provides additional considerations for priority areas, identified without consideration for whether a DES preexists.

It is not possible to quantify or draw firm conclusions on the degree to which expansion of existing systems might be possible – this is due to the fact that the precise layout of existing district networks is not known (system location in the IDEA database consists of a GIS latitude and longitude point) and as a result it is not possible to infer which building loads are already connected. What expansion potential might exist in the form of currently unconnected loads is therefore also not clear. The summary below reflects on what the data tells us about the potential for district energy in existing buildings, via a review of data at the Census Block Group level.

3.8.1 Potential Expansion of Existing District Systems

3.8.1.1 Heating and Hot Water-Led Potential

- Utilizing heat density as the key qualifying criteria and then utilizing supplementary screening criteria for heating and hot water loads described in Section 3 of this report to determine economic potential, there appear to be two locations in LA County, consisting of 8 CBGs in total, where the economic potential screening criteria are met, and therefore where building heat loads present an opportunity for expansion of existing heat networks. Both existing heat networks are hot water-based, both also run chilled water networks. Cooling density and the building diversity scores suggests potential for expansion of cooling networks. One of the two systems currently operates CHP. More detailed site analysis is required to confirm actual expansion potential. The analysis on building loads suggests that local cooling loads are greater than heating loads – only site-specific analysis would confirm and quantify expansion potential.

3.8.1.2 Cooling-Led Potential

- Using cooling density as the key qualifying criteria and then using supplementary screening criteria for cooling loads described in this report to determine economic potential, it is possible to suggest that there are up to 20 locations statewide, consisting of 81 CBGs in total where economic potential screens are met, to suggest that the building cooling loads present an opportunity for expansion of existing district chilled water networks. As with the heating expansion cases outlined above, data on existing systems suggests than in all but one case, both district cooling and district heating networks are already in place. The IDEA data suggests that 50% of these systems currently operate CHP.

Excepting the CBGs in proximity to the two systems described in the heating section above, those meeting economic potential screening criteria for cooling do not meet the screening criteria for heating because the local heating systems are steam-based. Expansion potential appears to exist, but decision making on the technical solution for expansion connections are not simple in such cases. Expansion of existing steam systems is not an efficient route toward energy sustainability due to the inherently high thermal losses. Expansion scenarios might be a) modification of existing steam systems to hot water (which is expensive and technically challenging) and then expand to new connections or b) establish a hot water network for expansion loads, connect that to the existing steam system, and then look to move existing steam system to hot water in phases.

3.8.2 Technical Potential Statewide

For CBGs that are not sufficiently close to existing district systems to meet the economic potential screening criteria, analysis of the data suggests that significant technical potential for district systems exists, although the means by which this potential is unlocked is less clear.

3.8.2.1 Heating and Hot Water-Led Potential

- For CBGs where heating and hot water energy density is the qualifying criteria, there are up to 62 CBGs that also have the necessary building diversity score on the cooling side to suggest they would be potentially attractive locations for a review of the potential for connection to district heating and cooling systems. There are 82 CBGs that meet the lowest heat density threshold; where this threshold is higher, for example due to different assumptions on district system operating delta-T, the number of CBGs that meet the criteria will be lower.

3.8.2.2 Cooling-Led Potential

- For CBGs where cooling energy density is the qualifying criteria, there are up to 103 CBGs that also have the necessary building diversity score on the heating and hot water side to suggest they would be potentially attractive locations for a review of the potential for connection to district heating and cooling systems.

3.8.3 Economic Potential

Analysis suggests that there are individual CBGs that satisfy the economic potential screening criteria for district energy and that that could contribute significantly to improving the business case of district systems.

Using conservative energy density thresholds that reflect a 10% discount rate and therefore a significantly higher hurdle than for the mapping analysis, there are 49 further CBGs that represent promising locations for district energy. The average thermal energy load in this CBG cohort expected in 2050 is 20 GWh and 87 GWh for heating (and hot water) and cooling respectively.

The vast majority of these identified CBGs (~75%) are not treated as expansion opportunities in the analysis as they are not in proximity to existing systems. While district system operators continue to look to expand their customer base, business development focuses on identifying new connections catchments where networks are present.

In these cases, the most obvious catalyst for district energy would be installation of a new system nearby, with the potential for existing buildings to connect to it. The analysis of growth and building turnover suggests that there will be significant large-scale development in each of the cities concerned, and therefore that planning zoning and prioritization of mixed-use sites close to these areas of high thermal energy demand presents a significant opportunity. In this scenario, feasibility studies examining the business case for connection outside the development site boundary would be a logical step in the design process. Proactive City or local Governments could incentivize building in such locations and developing local ordinances in order to encourage this kind of outcomes.

The 49 CBGs identified can be seen in maps included in Appendix D.

CHAPTER 4: Densification, Logistics, and Power Generation

4.1 Introduction

Modeling the build-out of Waste-to-energy projects requires a technical understanding of commercial and pre-commercial systems for biomass residue transportation, pretreatment, conversion, and power generation. Technology readiness and scalability, including performance limitations and costs, of densification, storage, logistics, conversion, and power generation technologies are reviewed by the project team to support a technical and economic analysis of scenarios for matching biomass residues with the state's power and waste heat needs. An overview of key commercial and pre-commercial technologies relevant to waste biomass utilization in California is presented in this Chapter. The Chapter concludes with a brief discussion on operation decisions for matching biomass feedstocks with the two most mature technologies, anaerobic digestion (AD) and combustion, to give a sense of the challenge of matching feedstocks with conversion technologies and need for managers to have strong technical knowledge or consultants with technical knowledge to ensure efficient, reliable system operation.

4.2 Pretreatment Considerations

Densification is the process of increasing the specific density of a fuel material to increase the energy density, thereby raising the value per ton. Biomass from plants has a low bulk density, so increasing the energy in each ton can lower supply chain costs. Drying, size reduction, and densification are the most common pretreatment steps for thermo-chemical conversion of biomass to energy. Other emerging pretreatments include water and chemical washing of biomass to lower ash, heavy metal, and alkali concentrations, which can lead to a range of emissions and operation issues (discussed in Section 4.6). Pretreatment steps for AD are largely slurrying/homogenization, contaminant screening, and pH adjustments. Emerging pretreatments for AD include physical, chemical, or biological degradation of recalcitrantcomponents like lignin and cellulose prior to feeding into the digesters. Pretreatment steps for gasification and combustion facilities are largely drying, mechanical size reduction and homogenization (grinding), and densification (palletization). Raw material collection and transportation, personnel, and drying make up the majority of total pretreatment costs. The process of altering the structure of the biomass can increase surface area, and decrease cellulose crystallinity and polymerization (Kratky and Jirout 2011). Mature dry cutting mechanisms include chipping, grinding, ball, vibro (like ball milling but with vibration instead of rotation), hammer, knife, and disk milling. Mature wet (10- 20% MC or higher) cutting mechanisms include extruders and colloid milling (Taherzadeh and Karimi 2008). Examples of some existing and emerging technologies for wet and dry size reduction are listed in the following Table 32.

In this analysis, the cost of pretreatment is accounted for in the waste conversion siting tool by extrapolating practices and costs from available pilot plant financial data, as discussed in Chapter 5.

Table 32: Energy Intensities of Comminution Technologies Based on Materials and Particle Sizes

Technology	Materials	Initial Size	Final Size	Energy intensity to 50 mm (kWh/t)
Shredder (knife, hammer, screw)	agriculture residue (corn stalks)	203	50 mm	1.69
	grass (switchgrass)	203	50 mm	0.49
	food waste (bones)		50-100 mm	
	paper	NA	4 cm	15.2
	woody materials		50-100 mm	
Ball Milling	sugarcane biomass			
	bagasse			
	straw			
Vibro Energy Milling	woody materials	22 mm	150 μm	
Knife Milling	grass (switchgrass)			
	straw			
	hardwood chips	NA	1.6 mm	130
	crop waste (MC <15%)			
	wood chip; wheat straw; corn stover (<7% MC)	NA	1-2 mm	80-120
Hammer Milling	straw (wheat at 8.3% MC)	20-50 mm	0.794 - 3.175 mm	51.55 - 10.77
	hardwood chips	22.4	1.6 mm	130
	straw (ag general)	22.4	1.6 mm	83-122
	corn stover (MC <7%)	22.4	1.6 mm	83-122
	wood chip; wheat straw; corn stover (<7% MC)	NA	1-2 mm	90-130
Disk Milling	wood chip; wheat straw; corn stover (<7% MC)	NA	1-2 mm	200-400

Technology	Materials	Initial Size	Final Size	Energy intensity to 50 mm (kWh/t)
Disk Milling	wood chip	NA	0.5 mm	750-850 (100 with increased temperature to 200 °C)
Two-Roll Milling	grain	~2 mm	400 μm	Emerging technology; 86% more energy efficient than hammer mills. High CAPEX and OPEX
Colloid Milling (wet disc)	material suspension (>=15% MC)			
	herbaceous biomass (rice straw)	NA	<2 mm	1500
	hardwood chips	NA	1-1.5 mm	120-160
Extrusion	grass (15-45% MC)			100-200
	OFMSW			
High-Sheer Effective Machines	15-20% MC			Lab-scale

Source: Data adapted from Kraty and Jirout 2011.

4.3 Transportation Modes

Biomass has a low energy density, making transportation a significant challenge and cost in the supply chain. A number of studies have developed estimates of transportation costs for a range of biomass types and distances. A detailed review of transportation modes in Sweden was performed in 1996 and found that tractors and trucks were more economic at shorter distances (~60 miles), while rail and marine modes were more economic at longer transportation distances (~140 miles) (Börjesson and Gustavsson 1996). The analysis estimated that sources of biomass were within 12 driving miles of rail ports and 30 driving miles of marine ports, which may not be the case for many agricultural and municipal locations in California. In addition to CAPEX costs, there is distance dependent and independent operation costs. An example of a distance-independent or fixed cost is the loading and unloading of biomass into trucks ($5/t for wood chips or straw) (Mahmudi and Flynn 2006). Distance variable costs like wages and fuel are often modeled as increasing linearly with distance traveled.

Truck transportation is the most common mode for moving biomass from point source to point of use. Trucks can reach rural areas where biomass is often produced and make use of the many smaller and larger road networks throughout the state. Trucks are limited in their carrying capacity (15-40 t) and can result in social and environmental impacts if road congestion arises. Optimal situations for truck transportation are when trucks have as few "empty" miles as possible, meaning that trucks transporting biomass on one leg of a trip can find another material to transport on the return trip. Enclosed heavy duty truck and tanker truck transportation is used for high-moisture organics like food processing wastes, high strength (high BOD content) wastewater, and FOG. For most municipalities, solid waste, organics, and recycling (paper cardboard) are stored in separate individual facility/ residential bins and picked up weekly by designated waste management trucks. Trucks are required to navigate roads, so no other mode of transportation is possible for these "first miles". Rail transportation can be an economic option for large quantities of biomass that can be delivered by truck to a loading station for long-distance transportation. Mahmudi and Flynn compared the economics of single mode rail to truck transportation in North America for wood chips and straw (Mahmudi and Flynn 2006). Like rail, marine transportation can be an economic option for large quantities of biomass that can be delivered by one mode (such as truck) to a loading station/ harbor for long-distance transportation. Biomass can be slurried and transported via pipeline if the bioenergy facility can handle high moisture biomass (Kumar et al. 2004). Examples of this may be a waste water treatment facility located close to a waste processing facility, organics composting facility, or source of manure.

In this analysis, distances for biomass transportation are kept to shorter distances (~60 miles), and all biomass is assumed transported by truck. The cost of truck transportation is discussed further in Chapter 5.

4.4 Storage

Storage of biomass is often necessary to reduce the effects of seasonality of fuel supply and to coordinate sub-seasonal feedstock collection and transportation schedules. In the case of agricultural residues, storage can occur onsite (whether in a storage unit or in the field), at the bioenergy conversion facility, or at an intermediate storage point. Manure and other wet wastes like food processing wastes tend to require storage systems both at the point of production and the point of use to control emissions, and odors. Municipal wastes are rarely stored at the point of production beyond the weekly pickup bins. Storage options that preserve fuel qualities of materials tend to be the most expensive. Controlling the loss of dry matter and the build-up of ammonia or available nitrogen (which when added directly to digesters can shock the system) are active areas of research.

Dry biomass storage can include in-field storage, such as baling, bundling, or piling, or storage in a structure at an intermediate location or at a bioenergy facility. Outdoor storage of baled agricultural wastes is the cheapest option and common for woody biomass, but can result in significant dry matter losses for herbaceous materials. Moisture content, ventilation and heat buildup must be carefully monitored in dry biomass storage to prevent ignition of the pile or unacceptable losses of dry-matter through decay. Materials should be dried to 15% MC prior to storage. Materials with smaller particle sizes will have higher dry-matter losses than those with less surface area and large particle sizes. Residues high in silica, such as grasses, may see a reduction in silica concentration over time, which would be beneficial for gasification systems.

The size of storage depends on the demand for fuel from the energy conversion facility and the need for a buffer, the cost of land, as well as the control of material decay. Table 33 lists dry-matter losses and costs collected from literature for dry biomass storage options. Costs associated with storage facilities include rent for land, the initial construction of the facility and purchase of any necessary processing equipment, labor costs for loading and unloading, and possibly costs for emissions and pest monitoring. While some cost estimates are available from previous techno-economic analysis of energy facilities, feedstock-specific storage costs are difficult to collect.

Table 33: Residue and Manure Storage Systems and Characteristics

Storage system type		Duration [month]	Loss rate [%]	Land Intensity	Labor Intensity
on-field	plastic cover	2 to 7	2 to 7	low	low
	winter freeze uncovered	2 to 7		low	low
	pole-frame structure	2 to 7	0.5 to 3.5	low	low
	rock bed	2 to 7	2 to 4	low	low
	sod bed	2 to 7	15	low	low
	lagoons			large	medium
storage facility	warehouse with drier	24+	negligible	medium	medium
ensile	mix with straw or corn silage	4+		low	medium
wet storage	pit storage			Medium	medium
	Storage over grate with trap for leachate	<<1	Large if leachate is not used	Low	high
compost facility	bin	2 to 7	20 to 50	low	low
	passive windrow	2 to 24	20 to 50	large	low
	active windrow	1 to 2	20 to 50	large	medium
	aerated static windrow	1 to 2	20 to 50	low	low
	in-vessel channel	1 to 2	20 to 50	low	high

Source: Lawrence Berkeley National Laboratory

Biomass with high moisture content spoils rapidly and can create a range of problems if left unstored. Not only does the material lose its value as a fuel, but it can attract pests that carry diseases, can create problematic odors, and can leach nutrients and contaminant into the soil and nearby water bodies. Published information regarding high-moisture biomass storage beyond hours or days is limited. Materials are shredded and dried or slurried and stored in tanks or piped to a treatment facility. Lagoons for manure and ensilage for agriculture residues are two exceptions. Ensiling is a wet-storage process that involves fermenting materials in anaerobic gas over several weeks. Herbaceous residues like grasses and maize, and food processing residues like fish waste, bread waste, brewery waste, rice bran and fresh fruit and vegetable waste (Kafle and Kim 2013; Krich 2005). In some cases higher (2-15%) biogas production rates from anaerobic digestion were achieved from ensiled feedstocks, compared to non-silage forms (Krich 2005).

Common types of storage for manure include: earthen or concrete pits, lagoons, large tanks, enclosed building, and covered dry stacks.

In this analysis, there is no limit assumed on the land footprint available for biomass storage. The cost of storage is accounted for in the waste conversion siting tool by extrapolating practices and costs from available pilot plant financial data, as discussed in Chapter 5.

4.4.1 Gas Storage

Biogas and biomethane can be stored for onsite or offsite usage. Low-pressure systems for storing of biogas are cheap as they require no gas upgrading, cleaning, or pressurization beyond what occurs naturally, but have limited storage capacity. Low-pressure systems (<0.1 to 6 PSI) like floating covers, gas bags (weighted and unweighted), water sealed gas holders, and floating roofs are commonly used by dairy farms above lagoons and at waste water treatment facilities (WWTF) above anaerobic digesters. Medium-pressure (10->2000 PSI) systems like compression tanks and high-pressure systems (2000-5000 PSI) like gas cylinders are costly and sensitive to contaminants in raw biogas; therefore, they are more typical in cases where the biogas is upgraded to biomethane (Krich 2005).

Biogas can be liquefied (LNG) and stored in cryogenic double walled cylinders for later use or for truck transportation. Common storage capacities for dairy farms range from 6000 to 15000 gallons (Krich 2005). As the cryogenic liquid heats during storage, there is boiloff of methane, which must be vented or captured and liquified. This often creates a short storage period of ~1 week before gas losses become too costly.

Emerging options for gas storage include adsorption storage (ANG), whereby methane is adsorbed onto a nanoporous material like zeolites or metal organic frameworks to provide a high working capacity at near ambient temperature and pressure. Adsorption storage systems are being developed for vehicle scale applications, and have yet to be advanced for bulk storage.

Table 34: Comparison of the Three Storage Technologies

Characteristic	CNG	LNG	ANG
Storage pressure	High Pressure (3600 psi)	Low pressure (Atm)	Low pressure (500-800 psi)
Storage Temperature	T amb	-260°F	T amb
Tank	Heavy Cylinder	Double-walled, insulated tanks	thin tank of various shape (with carbon monolith)
Volumetric rapport	220 v/v	600 v/v	150-200 v/v
Scale	small - middle scale	middle-large scale	small - middle scale
Main uses	•Storage • Transportation • Fuel for light vehicle	• Storage • Fuel for heavy vehicle and ship • Energy generation	• Storage • Fuel for light vehicle • Transportation
Advantages	• technology well known and mastered. • very simple (only need a compressor and a vessel)	• best density •long distance transportation •large scale	•all advantage of CNG •cheapest of all technology

Source: Lawrence Berkeley National Laboratory

The energy penalty associated with the compression and liquefaction is between 5 and 10% of stored gas energy, depending on the manufacturer. In addition, thermal management for charging and releasing gas from the storage system needs to be optimized to increase overall efficiency for all storage approaches.

Compressed natural gas (CNG) is a gas (NG or biogas) which, after being compressed, reaches a high pressure of 3,600 psi (250 bars). After being cleaned and dried, the gas is compressed and then stored inside high-pressure cylinders. Such vessels need to be durable to handle the strong constraint generated by the high pressure. Under this state, the density of the gas is increased in order to have more gas and thus more energy available in a reduced volume. CNG has a density about 220 times greater than that at normal conditions of temperature and pressure (atmospheric).

There are two types of stations allowing for NG refueling: fast-fill and time-fill. As this project focuses on the use of bioenergy for power and waste heat applications, the use of biomethane for CNG vehicles is not further investigated.

Four types of cylindrical tanks can be found on the market, depending on their composition, durability and fabrication. They are shown in Table 35.

Table 35: Description of Cylindrical Tank Types

Tank Type	Description
Type I	All metal (steel and aluminum)
Type II	Hoop wrapped steel or aluminum
Type III	Fully wrapped steel or aluminum
Type IV	All composite (non-metallic)

Source: Smith and Gonzales (2014)

At CNG pressure, only the most durable materials can be used because of the strength and resistance involved. This explains why most of CNG tanks are either Type III (fully wrapped steel or aluminum) or Type IV (all composite). Such vessels require a production with precision and high-quality material: this necessarily causes high prices. Such tanks cost between \$70,000 and \$130,000 each for large scale (industrial use) and around \$3,000 for vehicles (Smith and Gonzales 2014). Compressors for CNG usually cost between \$4,000 and \$550,000 (Smith and Gonzales 2014). In addition to the cost of the compressors, the process itself needs a lot of energy and thus consumes a lot of electricity. During the compression, the electrical consumption represents around 10% of the initial energy content of the gas. The cost to compress to 3,600 psi (electricity and CAPEX of compressor) is around 1,9 \$/GGE (\$0,33 just for electricity) (Pfiefer et al. 2016).

Natural gas is converted to LNG by being cooled down to -260 °F (-162 °C). At this temperature, the gas has changed state and has become a liquid. This process reduces its volume by a factor of more than 600 compared to atmospheric conditions, allowing it to be efficiently transported and stored.

Liquefaction consists of three main steps:

- Prior to liquefaction, the raw feed gas needs to be cleaned in order to remove contaminants. This is of paramount importance for maintaining a proper functioning of the process.
- Then, the gas is cooled to allow water to condense and then further dehydrate to remove even small amounts of water vapor. If mercury is present in the feed gas, it must be removed during this stage. The liquefaction process can follow multiple variations and cycles such as the Phillips Cascade process, the Mixed Components Refrigerant (MCR®), the Pre-Cooled Joule-Thomson Cycle, or the Nitrogen Refrigeration Cycle and others.
- Finally, the liquefied natural gas is pumped in double-walled vacuum insulated tank for storage at atmospheric pressure where it will remain until being moved. The LNG does not require a cooling system while being transported. The walls of the inner tank, composed of special steel with high nickel content as well as aluminum and pre-stressed concrete, must be capable of withstanding cryogenic temperatures. This temperature (boiling NG temperature) remains constant even if heat is added (thanks to the thermodynamics of steam evaporation) as long as the gas vapor is removed. This “lost” gas, about 0.15% of the volume per day (or higher at smaller, less efficient facilities), is used to fuel the liquefaction facility, LNG transport ships or LNG terminals.

- Concerning the regasification, a warming system is used: the liquid is vaporized just after being heated.

A typical LNG liquefaction facility includes three or four trains of liquefaction. The LNG production capacity of an individual train can reach 5 million tons per year. Indeed, most of the liquefaction facilities are large because of the high investments needed to build such plant. Moreover, all the LNG produced must to be stored meaning that construction of big storage tank near each LNG facility is needed. LNG storage tank can reach 7,000,000 scf (200 000 m^3).

As the initial investments are high, the uses of LNG are mainly large-scale and not further investigated in this project.

Adsorbed Natural Gas (ANG) storage is not a new technology and was first investigated in the 1990's as an alternative to CNG storage. CNG storage is indeed the widest spread technology to store gas around the world, as it is used in the industry, for vehicles and almost everywhere where gas is needed. As the standard pressure of this kind of storage is between 3,000 and 3,600 psi, this process needs high power compressors and very durable tanks. This explains the high costs and weight of CNG facilities and storage cylinders.

Although advances in ANG natural gas storage have been achieved, the technology has only been commercialized for a few small markets. For example, activated carbon and zeolite based pickup trucks are currently being prototyped by companies like Ingevity. With advancements in adsorbent materials, ANG could be a possible alternative to CNG in larger markets, especially for gas fueled vehicles where size and weight are important factors. ANG can replace heavy, expensive CNG tanks with low pressure (500—800 psi) conformable tanks filled with adsorbent material. This increases tank storage capacity that can be found in various shapes that use void spaces of the vehicle.

Adsorbent storage technology functions on the following principle: the amount of natural gas stored in a pressurized cylinder is greatly improved by placing a porous material, such as activated carbon substrate, inside the cylinder. However, this principle has a limit and is only valid in certain conditions of pressure and temperature (up to about 1800 psi), after which the carbon becomes a greater impediment to storage capacity than it can provide through adsorption.

Presently, there is no large-scale manufacturing or production of ANG technology, and this lack of development and experience has an effect on the price. ANG is not considered further in this project.

The cost of biogas storage and biomethane pipeline transportation is accounted for in the waste conversion siting tool by extrapolating practices and costs from available pilot plant financial data, as discussed in Chapter 5.

4.4.2 Gas Upgrading and Cleanup

4.4.2.1 Biogas and Syngas

Microbial degradation of biomass generates biogas, which contains carbon dioxide, methane, hydrogen sulfide, water and other minor contaminants. The composition of biogas depends on a number of factors such as the type of anaerobic digester, how it is operated, and the type of substrates that are treated. In most cases, biogas must be processed to remove impurities (cleaning) and carbon dioxide (upgrading) to meet air quality standards and increase the energy content of the gas. When gas is upgraded to meet pipeline quality standards (indistinguishable from natural gas) it is referred to as biomethane. While raw biogas can be used in boilers, but typically H_2S is removed to below 250 ppm. Upgrading biogas by removing CO_2 (to achieve >30-35 mol% CH_4) is commonly done prior to combustion in gas engines and turbines.

Table 37 lists common impurities found in biogas, reasons for their removal, and common methods for their removal. The Office of Environmental Health Hazard Assessment and the Air Resources Board in California developed a list of constituents of concern (Table 38) that could pose health risks and that have been found at levels higher than natural gas in biogas samples from landfills, dairy farms, and sewage sludge treatment. It is suggested that these constituents be monitored and that additional data be developed for biogas from the anaerobic digestion of OFMSW, crop residues, and gasification of woody biomass and crops (California Air Resources Board and the Office of Health Hazard Assessment 2013).

Table 36: Biogas Characteristics Based on Production Facility Type

Parameter	Units	Landfill gas			Biogas from Anaerobic Digesters			Wastewater Treatment Plants			Natural gas	Impacts on biogas utilization
		Low	Ave.	High	Low	Ave.	High	Low	Ave.	High		
Lower heating value	MJ/Nm3	8	16	24	20.5	23	24.2	20.5	23	24.2	39	
CH_4	% (mol)	20	50	70	60	65	70	55		77	85-92	
H_2	% (mol)	0	3	15	0	0	0	0	0	0	0	
CO_2	% (mol)	15	37	60	30	35	40	19	30	45	0.2-1.5	Decreasing calorific value, anti-knock properties of engines, corrosion
H_2O	% (mol)	1	4	7	1	4	7	1	4	7	0	Corrosion, damage due to formation of condensate and ice
N_2	% (mol)	1	10	50	0	1	5	0	1	5	0.3	Decreasing calorific value, anti-knock properties of engines
O_2	% (mol)	0	1	10	0	1	2	0	1	2	0	Corrosion
H_2S	ppm	0	1000	20000	0	500	6000	0	500	6000	1.1-5.9	Corrosion, catalytic converter poison, emissions and health

Source: Lawrence Berkeley National Laboratory

Table 37: Methods of Removal for Common Biogas Impurities

Impurity	Main Problems	Removal Methods
Water	Condensation in gas pipelines, causing corrosion	Cooling: simply by burying pipes in ground Compressing: with compressor Adsorption: SiO_2, activated carbon, molecular sieves Absorption: glycol solutions or hygroscopic salts
Hydrogen Sulfide (H_2S)	Corrosive to steel reactors, toxic at > 50 ppm, can lead to formation of SO_2 and H_2SO_4	Precipitation in digester liquid via addition of Fe^{+2} or Fe^{+3} Adsorption on activated carbon Chemical absorption: washing with NaOH, passing through Fe-coated support materials, absorption on ferric chelate solutions
Oxygen (O_2)	Dilution (reduction of biogas heating value)	Adsorption with activated carbon, molecular sieves, membranes
Siloxanes	Forms silicon oxide when burned, and this particulate white powder is problematic in gas engines	Cooling the gas, adsorption on activated carbon, activated aluminium or silica gel, absorption in liquid mixtures of hydrocarbons
Particulates	Mechanical wear and tear in gas engines and turbines	Mechanical filters

Sources: Petersson and Wellinger 2009; Yang et al. 2014.

There are several processes existing for the purification of biogas:

Adsorption (Pressure Swing Adsorption - PSA)

The PSA technology is used to separate CH_4 from N_2, O_2 and CO_2, since the CH_4 molecule is larger than the other molecules. The adsorption material used for biogas upgrading adsorbs H_2S irreversibly, and so is considered toxic to PSA process. For this reason, initial removal of H_2S is required prior to treatment. The concentration of CH_4 after upgrading is typically about 96–98%. However, high methane losses (2-10%) can be expected in general. Methane losses are linked with high purity requirements.

Absorption (washing with water, amines, or organic washing)

With the pressurized water scrubbing, water is used as a solvent. Indeed, the solubility of CH_4 in water is much lower than that of CO_2. Normally, H_2S can be removed at the same time as

CO_2 since its solubility in water is higher than that of CO_2, however because dissolved H_2S can cause corrosion issues, pre-treatment of H_2S is normally require with this process. Water scrubbing can achieve a methane purity of 80–99%, depending on the volume of non-condensable gases such as N_2 and O_2 that cannot be separated from methane. The methane losses, mainly due to dissolution in water, are usually between 3% and 5%.

Membrane separation

Membrane technology is a separation method at molecular scale. It has several advantages, including low cost, energy efficiency and easy process. For biogas upgrading, CO_2 and H_2S pass through the membrane to the permeate side, while CH_4 is retained on the inlet side. Since some CH_4 molecules may also pass through the membrane, achieving a high purity of methane involves large losses of it. Membrane on optimal processes can deliver a methane purity of 98% with recovery of 99%.

Cryogenic separation

Due to the different condensing temperatures of CH_4 and CO_2, they can be separated through condensation and distillation. To avoid problem such as freezing during the cryogenic process, water and H_2S must have been removed previously. When methane is condensed, N_2 and O_2 can also be separated out. Cryogenic separation process needs to compress raw gas to a high pressure (up to 3,600 psi) meaning that a large amount of energy (around 5 to 10% of the biomethane produced) is needed and consumed in the process. However, cryogenic separation shows great advantages in producing liquid and high-purity biomethane. In addition, the losses of CH_4 can be very low, usually lower than 1%.

Table 38: Constituents That May Pose a Risk to Human Health Detected in Some Types of Biogas

10	Landfills	Dairies	WWTF
Antimony	X		
Arsenic	X		
Copper1	X		
p-Dichlorobenzene	X		X
Ethylbenzene	X	X	X
Hydrogen Sulfide	X	X	X
Lead	X		
Methacrolein	X		
n-Nitroso-di-n-propylamine	X		
Mercaptans (Alkyl Thiols)	X	X	
Toluene	X	X	
Vinyl Chloride	X		X

Source: California Air Resources Board and the Office of Health Hazard Assessment 2013.

In this analysis, scenarios are modeled that assume either raw biogas or biomethane is produced at a Waste-to-energy project. The costs associated with the conversion of biogas to biomethane are extrapolated from demonstrative costs of pilot projects, as discussed further in Chapter 5. Syngas from gasification is a blend of carbon monoxide, carbon dioxide, and hydrogen, and no assumed additional syngas treatment at the gasification facility.

4.5 Power Generation Options

4.5.1 Conversion Technologies

Three classes of biomass residue energy conversion technologies are included in this project: direct-fired combustion, gasification, and anaerobic digestion (wet stand-alone, dry stand-alone, co-digestion at wastewater treatment facilities, and dairy stand-alone). Byproducts from these technologies include ash, biochar, and digestate. The potential for biochar and digestate generation, land disposal, and use for carbon sequestration purposes within California is characterized in detail in a pending journal article by Breunig and colleagues.

4.5.1.1 Direct-Fired

Direct combustion is the most common energy conversion technology for low moisture solid biomass. Hot flue gas resulting from the combustion process is used to produce steam in a boiler, which drives a steam turbine to generate electricity, with the option to also produce heat (cogeneration) via the steam offtake. In cogeneration mode, increased heat production necessarily reduces electrical output. Stoker boilers are quite simple and require little biomass pretreatment, making them viable for small-scale projects. Jenkins provides a global reaction for the combustion of biomass fuel (the first compound listed) in air, but notes that fuel properties will determine the outcome and performance of the combustion process (Equation 6) (Jenkins et al. 1998). There are more than fifteen elements inherent in biomass materials, but concentrations may be quite different even in the same biomass type depending on the amount of contaminants or soil delivered along with the biomass.

$$\begin{aligned} &C_{x1}H_{x2}O_{x3}N_{x4}S_{x5}Cl_{x6}Si_{x7}K_{x8}Ca_{x9}Mg_{x10}Na_{x11}P_{x12}Fe_{x13}Al_{x14}Ti_{x15} + H_2O \\ &\quad + n_2(1+e)(O_2 + 3.76N_2) \\ &\quad = n_3CO_2 + n_4H_2O + n_5O_2 + n_6N_2 + n_7CO + n_8CH_4 + n_9NO + n_{10}NO_2 + n_{11}SO_2 \\ &\quad + n_{12}HCl + n_{13}KCl + n_{14}K_2SO_4 + n_{15}C + \cdots \end{aligned} \tag{6}$$

Direct-fired systems tend to produce ash with 30-40% carbon (EPA Combined Heat and Power Partnership 2007). Fluidized bed boilers burn biomass in a bed of inert particles that are suspended by combustion air. The configuration increases mixing of fuel and oxygen to achieve higher efficiencies, less ash production, and lower NO_x and SO_2 emissions than stoker boilers.

Direct-fired technologies generate bottom ash (60 to 90% of ash from fixed beds), coarse fly ash (2 to 30% from fixed beds), and fine fly ash (primary product from fluidized beds, 2 to 15% of ash from fixed beds). Each ash type tends to accumulate different elements, with volatile heavy metals and semi-volatile K concentrating in fine fly ash, and non-volatile elements concentrating in bottom ash. Fly ash from fluidized beds tend to have lower concentrations of volatile elements due to the lower combustion temperatures used (van Eijk et al. 2012). In general, ashes from ligneous feedstocks are characterized by Si, K, Mg, and K, ashes from herbaceous fuels are characterized by Si, K, Ca, and lower heavy metals (van Eijk et al. 2012), and ashes from MSW can have higher amounts of heavy metals. Ashes generated from fluidized bed boilers can contain bed materials (SiO_2). If biomass is co-combusted with coal, the resulting ash properties will be dominated by the coal ash properties.

For both types of boilers, moisture content in the feedstock should be minimized, particle size should be relatively homogeneous, and feedstocks high in potassium ash content (e.g. green wood, fast growing biomass like grasses) should be avoided to prevent slagging and fouling. Biomass containing chlorine (e.g. grasses and straw) can cause corrosion, and biomass with high sulfur content (e.g. construction debris, paper mill sludges) should be co-fired with limestone to reduce SO_2 emissions. Both types of boilers can be co-fired with coal.

In this project, it is assumed that some low moisture biomass residues can be directed to existing excess capacity at solid biomass combustion power plants in 2014. The fraction of low moisture biomass residues that can be diverted to existing excess capacity at solid biomass combustion facilities in California is estimated by Breunig and Colleagues (Breunig et al. 2017; Breunig et al 2018). However, due to the air quality impacts of combustion facilities, it is assumed all future distributed waste-to-energy projects that manage low moisture biomass residues are either dry anaerobic digesters or gasification projects.

4.5.1.2 Gasification

Gasification is the process whereby solid biomass is heated in an oxygen-limited environment to produce a flammable gas, or syngas, that can be used to drive gas engines, turbines or fuel cells in generating electricity and heat. This process typically takes place in a specifically designed reactor vessel, that can vary in terms of features and operational nature.

Direction of gas flow through the reactor vessel dictates whether the unit is updraft or down-draft technology. Cross draft gasifiers are an available configuration, but are generally considered to be more complex to operate and more expensive to maintain. Updraft gasifiers offer simple operation, high fuel conversion efficiency, low exit gas temperature and fuel flexibility (size and moisture content), but with higher levels of volatiles and tars in the syngas – these need to be removed in advance of use in a generator. Downdraft gasifiers produce fuel with lower levels of tar, but with particulates, which would have to be removed prior to use. The simplicity of gas cleaning to a high purity means they are better suited to CHP applications. Due to pressure drop issues, there is also less fuel flexibility with a downdraft unit.

Fixed bed (updraft and downdraft) and fluidized bed gasifiers (updraft only) differ in their configurations and costs, as well as their sensitivity to variations in feedstock particle size and moisture content. Fixed bed gasifiers direct air flows across a bed where the biomass is placed, while in fluidized bed gasifiers, biomass is heated in a bed of inert materials like silica which are suspended with air flow. Fluidized bed gasifiers can achieve a higher value syngas than fixed bed gasifiers and can handle greater variations in biomass moisture contents, but are much more expensive. These systems produce a number of byproducts depending on the feedstock and operation conditions. In high temperature gasification, molten ash is generated and cools into slag.

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Feedstocks with high ash and moisture content and low volatile solids can be gasified (i.e. poultry litter, dairy manure, alfalfa), but will generate a lower fuel heating value and more byproducts. Feedstocks with heavy metals like Zn and Mn (i.e. switchgrass, red cedar) will generate chars with high heavy metal accumulation, making them more difficult to manage (Qian et al. 2013). Sulfur and chlorine will interact with alkali metals and K, respectively, leading to issues with deposits, emissions, ash sintering and corrosion (IEA Bioenergy). Feedstocks with low density can require more frequent feeding, and can therefore be more challenging to gasify (e.g. mulch, bark without densification) (Sharma 2011).

Ash from bioenergy industry is commonly used in Europe for forestland, agriculture, or landscaping purposes. Ash is not a source of nitrogen, and application is set around a minimum content and availability of N, P, K, Ca, Mg, or S and maximum content of heavy metals (Cd, Cr, Cu, Pb, Mn, Zn) and in some cases polycyclic aromatic hydrocarbons (PAH) (KEMA). Intermediate storage sites are common for handling the seasonality of ash production and the need for large quantities of ash in applications such as construction. Pretreatment like metal separation, screening, blending with compost, or wetting, may also be necessary to reduce dust and prepare ash for direct land application (KEMA).

In this project, gasification projects are included at potential future infrastructure for managing low moisture biomass residues in 2020 and 2050.

4.5.1.3 Anaerobic Digestion

Anaerobic digestion is the microbial degradation of organic matter in the absence of oxygen. Feedstocks are fed into batch or continuous single or double stage reactors where elements undergo biological transformations to biogas comprised mostly of carbon dioxide and methane, and a high moisture solid digestate. Digesters are classified as mesophilic or thermophilic depending on the temperature at which they are maintained. Wet digestion is the oldest and most common technology, referring to the conversion of feedstocks with moisture content greater than 20%, such as sewage sludge, manure, municipal food waste, high strength wastewater like poultry blood, and fats, oils, and greases. Dry and semi-dry anaerobic digestion (sometimes referred to as “high solids”) accepts wastes with moisture content <20% such as municipal yard waste (i.e. green waste), silage, manure, poultry litter. Feedstocks that are recalcitrant to biological breakdown are typically characterized as having high lignin and/or ash content. Pre-treatment of feedstocks is often necessary to remove recalcitrant contaminants, homogenize, and correct for moisture content and pH.

Digestates from anaerobic digestion will biologically stable if feedstocks are processed for an adequate period of time. Their composition with be determined based on the recalcitrant contaminants and ash in the feedstocks. Dewatering is often performed to reduce the cost of transporting digestates. For wastewater treatment facilities with anaerobic digesters, the liquid fraction is often sent back through the wastewater treatment facility for nutrient removal. Solid digestates have been well characterized for manure, and manure-agroindustrial waste blends (silage, manure, blood industry residues), but are poorly characterized for municipal food waste. Digestates will have lower decomposable organic matter and higher concentration of nitrogen than the feedstocks used (i.e. ingestates).

In this project, stand-alone dry anaerobic digesters, stand-alone wet anaerobic digesters, and co-digestion at the existing wet anaerobic digesters at waste water treatment facilities are modeled. Additional details on each anaerobic digester technology cost and performance are provided in Chapter 5. Particularly biogas and syngas production yields by feedstock and technology type are provided.

4.5.2 Energy Generation Technologies

4.5.2.1 Overview

This section provides an overview to the distributed generation technologies included within the Techno-Economic Analysis outlined in Chapter 5. A summary cost table is provided in this section for the purposes of side-by-side comparisons. Summaries below assume a thermally-led CHP operating strategy,[11] to ensure that renewable resources are utilized in the most efficient way possible in the context of providing thermal energy to buildings.

4.5.2.2 Internal Combustion (IC) Engines

Internal combustion engines function by transforming energy from fuel burning into mechanical energy via pistons and a driveshaft, with the mechanical energy generated by the ignition and expansion of hot gases within the engine piston chambers. This is subsequently turned into electrical energy via the connected generator. If operating in CHP mode, thermal energy may also be taken from the engine jacket, engine cooling water circuits, lubricating oil (all low grade heat, less than 160 °C) and exhaust gas heat exchange (high grade heat, higher than 160 °C). These thermal energy supply temperatures are ideal for space heating, hot water (utilizing low and high grade heat) and heat-for-cooling applications via the use of absorption chillers (high grade heat only) in district energy applications. When not operating in CHP mode, the heat offtake is dumped to atmosphere. This may occur during periods where electricity grid stability is a priority and there happens to be no thermal sink available.

IC engines range in capacity from tens of kilowatts to over 5 MW electrical output. Electrical efficiency of when utilizing natural gas is typically in the range of 25-40% (Zogg et al. 2007, Clarke et al. 2012), with a heat-to-power ratio of approximately 1:1 – 1.2:1. For biogas applications, electrical and thermal efficiency are both somewhat reduced due to the normally reduced energy content of the fuel per unit, compared to pipeline natural gas – in order to

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[11] This should not preclude scenarios in which CHP can provide high value grid support services for an equivalent of a few days of the year, but is rather a general operating principle. It could also allow for scenarios in which electric load leads operations, in cases where thermo-electric generation was possible – CHP engines would ramp up and ramp down according to the load being met via the CHP thermo-electric capacity.

generate equivalent energy outputs to a natural gas application, a larger capacity engine is required.

The main advantages of IC engines are that they are a widely available, relatively cheap, very well understood and mature technology utilized in a wide range of applications. As a result they are the most widely used prime moved type for CHP applications worldwide. They are well known for providing generating flexibility in terms of fast start and ramp-up times and capability to modulate down to around 50% output, although there is an efficiency penalty for a reduction in output - IC engines lose approximately 8-10% efficiency when operating at 50% capacity (Clarke et al. 2012). IC engines in large power plants can ramp up to full capacity in less than 10 minutes; a speed that earns the "quick start" or "non-spinning reserve" designation used by utilities such as California ISO and PJM (Wärtsilä).

The main drawback of IC engines relate to costly maintenance. IC engines have many moving parts and are noisy in operation, resulting in a relatively high degree of wear and tear (Clarke et al. 2012).

4.5.2.3 Gas Turbines

Gas turbines (GT) also transform energy from the fuel burning process into mechanical, and subsequently, electrical energy. Gas turbines make use of a compression-expansion cycle to generate electricity. At the start of the combustion cycle, incoming air is compressed before entering a chamber, where high pressure fuel is added to the pressurized air, and this gas mixture is ignited and expands rapidly. The air and exhaust pass through a turbine, which converts the energy from gas expansion into turbine rotation and produces electricity via direct connection to a generator. For CHP systems, the exhaust gases from the combustion process are passed through a heat recovery device, such as a boiler.

Gas turbines range in capacity from approximately 2 MW electrical output up to hundreds of MW (which are typically combined-cycle configuration). The electrical efficiency of simple cycle gas turbines is in the range of 33-41%, with overall efficiency of combined-cycle CHP plant reaching (Zogg et al. 2007, Pilavachi 2002). Heat-to-power ratio varies according to means of thermal energy exchange (i.e. heat recovery boiler, heat exchanger) extending as high as 1:2. The specification of heat to power ratio will normally reflect the marginal benefits of supply of thermal energy and concurrent loss of electrical output.

For CHP applications, gas turbines are typically utilized in a combined-cycle configuration, whereby, in the second stage of operations, a back-pressure steam turbine takes water heated from the gas turbine flue gases and converts this thermal energy into electricity, and heat from the condensed steam, and in the final stage, a heat recovery boiler removes the remainder of the useable heat from the flue gases. Second and third stage activities may provide thermal energy to district thermal systems.

Gas turbine technology is mature and widely available. Applications are typically expected to operate at full power, although partial load operation is possible. Ramping electrical and thermal output up and down in response to demand is not typical due to technology characteristics, and as a result operate best as CHP applications when supplying baseload thermal energy. The nature of the technology means that it is relatively cheap to operate and maintain, and it remains a reliable option for large capacity applications (> 10MWe).

4.5.2.4 Steam Turbines - Combustion

Steam turbines generate power by via pressure reduction of a flow of steam through a turbine, which generates mechanical power, converted via a generator to electrical power. Steam turbines may be either condensing or non-condensing. In a condensing system, steam is condensed to water and the heat of condensation is captured as useful energy to maximize turbine power output. In a non-condensing system, the outlet steam has sufficient energy content to be utilized for thermal energy generation as part of a CHP system (Clarke et al. 2012). Typically, steam turbines have several pressure drops within the system, referred to as stages. The efficiency of steam turbines increases with the number of stages and as a result the larger the steam turbine, typically the more efficient it is (Clarke et al. 2012).

With proper maintenance, steam turbines are expected to last for more than 50 years.[21] Steam turbines have a slow ramp-up speed; when used in large commercial power plants, they can require up to 12 hours to reach full generation capacity (Wärtsilä).

Steam turbines are a very mature prime mover technology, and have demonstrated economic feasibility and commercial viability above > 2 MW in capacity (van Eijk et al. 2012). To operate in CHP mode, steam turbines are typically connected to combustion plant, such as a wood-fired boiler. The boiler raises steam via combustion of the fuel, which in turn drives the steam turbine. Implemented in this configuration, CHP does not achieve the overall efficiencies of some of the other options. It is also not flexible in terms of output – it is a solution that is best suited to meeting a specific thermal load (baseload or otherwise) as once the boiler at operating temperature, modulating output carries an efficiency penalty, particularly on the electrical side, as the steam turbine will not be processing the appropriate volume of fluid to operate optimally.

4.5.2.5 Fuel Cells

In a fuel cell, energy stored within a fuel's chemical bonds is converted directly to electrical energy via electrochemical reactions. Fuel cell units – referred to as stacks – contain two electrodes (a positively charged cathode and a negatively charged anode) and an electrolyte solution sandwiched between the two. Within the fuel cell, hydrogen from the fuel source and oxygen from the ambient air are ionized at the electrodes, creating a flow of electrons through the circuit. The reaction at the anode is best suited for ionizing pure hydrogen, so other fuel sources must be reformed to create a stream of pure hydrogen before entering the fuel cell. This reformation process can take place either within the fuel cell or separately, upstream in the energy system.

In terms of specific technologies, molten carbonate fuel cells (MCFCs) and solid oxide fuel cells (SOFCs) are typically the preferred options for stationary applications. Both operate at high temperatures of 600 °C and 1000 °C, respectively and are suited for running on fuels such as natural gas, methane, biogas or syngas. The higher operating temperature of these fuel cell technologies makes them especially attractive for CHP applications (Buonomano et al. 2015).

The fuel cell technology variants identified above as applicable to the types of projects discussed within this project range in capacity from approximately 100 kilowatts to tens of megawatts – the technology is modular within single units in terms of the number of cells that may be included in a single stack and also the number of units that make up a single installation. Fuel cells typically achieve up to 50% efficiency in conversion to electrical energy, and 90% efficiency when waste heat is captured in a CHP system (Laporte and Shook 2015). Commercial fuel cell systems run on biogas report electrical efficiencies in the range of 42-47% and overall CHP system efficiency of 80% (Remick 2009).

Fuel cells are a promising power generation technology due to their high electrical efficiency and lower source emissions. However, compared to other CHP technologies, they are still relatively immature, and therefore more costly, and unit longevity has been an issue, although both of these issues are being addressed as it becomes more mature.

The main barrier to uptake is the high capital cost of the units themselves. As there are a very small number of moving parts, operation and maintenance costs are low, although the lifetime of the cell 'stack' is still being proven – currently manufacturers state a reliable operating stack lifetime of 50,000 – 60,000 operating hours, which equates to approximately 10-12 years. At this point, the stack must be replaced, but in principle the remainder of the plant assemblies should continue to operate under a normal maintenance regime for many more years.

4.5.2.6 Organic Rankine Cycle

The Organic Rankine Cycle (ORC) is a system that converts heat to useful work based on the thermodynamic Rankine Cycle, using an organic fluid as the working medium (Jradi and Riffat 2014). The advantage of using an organic fluid (as opposed to water) as the working medium is the lower boiling point, which allows for useful work to be generated from waste heat at lower temperatures, typically resulting in greater efficiencies. The ORC unit is a closed process, where the pressurized working medium is vaporized and slightly superheated in the evaporator utilizing steam from a combustion boiler, which in this context, will burn low moisture biomass waste. The working fluid is then expanded in an axial turbine, which is directly connected to a generator. Then, the expanded working fluid passes through a regenerator, where heat is recovered and then enters the condenser and the cycle begins again (van Eijk et al. 2012). The heat source typically generates thermal energy between 90 and 400°C, normally as superheated steam (Maraver et al. 2013). This temperature is low enough that problems with ash agglomeration and sintering are seldom encountered.

The electrical efficiency of ORC systems ranges from 8-23%, depending upon the size of the system. When waste heat is captured, ORC systems often achieve a thermal efficiency of 60-80% (Maraver et al. 2013), with a significant range in heat-to-power ratio. As the heat-to-power ratio is relatively low, the economic viability for this technology may present a challenge due to the relatively low volume electricity sales potential. – it is not considered to be a particularly good fit for the type and scale of projects proposed here.

Specifically, for decentralized CHP plants fueled by biomass combustion, ORC is the most well-proven and commercially available technology. There are currently over 140 biomass-fired ORC plants in Central Europe (Maraver et al. 2013).

It should also be noted that the footprint of larger ORC installations is significant, due in large part to the complexity of the final engineered solution, which incorporates an array of supporting plant. This physical size presents an obvious challenge on the margins of, or embedded within, existing urban centers.

4.5.2.7 Stirling Engine

Stirling engines (SE) present an alternative to ORC for small CHP systems (3-150 kW) (Maraver et al. 2013). The operation of the SE is based on the thermodynamic Stirling Cycle, which can theoretically reach the Carnot efficiency, which is much higher than the Rankine efficiency. However, SE are less technologically mature than ORC. Stirling engines operate in a closed cycle, where the working gas (often helium, nitrogen or hydrogen) is alternately compressed in a cold cylinder volume and expanded in a hot cylinder volume.

The electrical efficiency of stirling engine systems ranges from 15-35%, and the total CHP efficiency ranges from 65-85%. The heat source needs to be between 650 and 1100 °C for sufficient operation of a stirling engine (Maraver et al. 2013). These units are best suited to single-building CHP projects rather than the scale associated with district energy.

4.5.2.8 Microturbines

Micro-Turbines (MT) follow the same principles as larger scale gas turbine units (Combined Heat and Power Partnership 2015b). The turbine configuration is slightly different to large units as microturbines need to operate efficiently at a significantly lower volume flow. The compression-expansion cycle that takes place rotates the turbine shaft which via connection to a generator,[12] produces electricity. For units installed as CHP systems, the exhaust gases from the combustion process are passed through a heat recovery device, such as a boiler or heat exchanger.

Units range in capacity from 30 kilowatts to 1.3 Megawatts, although they are designed for installation as standalone units or in parallel as modular units – a leading manufacturer states that up to 10 units may be installed in parallel, which for the largest unit they sell translates to 10 MW of installed electrical capacity.

Microturbines typically reach up to 30% efficiencies for conversion to electrical energy, although this is impacted by the need for gas compression prior to injection into the microturbine – the load on any such compressors necessary is considered as part of the overall unit efficiency – electrical efficiency is typically 22-28% adjusting for compressor load. In CHP mode, heat-to-power ratio is 1.37-2.17, depending on the capacity of the unit (larger units have lower heat to power ratio) with overall efficiencies of 63-71%.

The design of the technology means that load following operation for single units come at an efficiency cost, although due to the relative impacts on electrical and thermal output, the EPA notes that at 50% load, the impact on a single unit in CHP mode is only 5% overall.

Microturbines also offer the capability to operate on numerous liquid and gaseous fuels, and fuels of varying quality, including unprocessed gas straight from the ground, and process offgases, although clean-up of flue gases from the turbines need to reflect this.

[12] Generator module technology and the means of connection to the driveshaft varies by manufacturer.

Table 39: Summary of Power Generation Technologies

Prime Mover Technology	Power Output (kW)	Tech. Maturity (Scale 1-3)	Electrical Efficiency	Thermal Recovery	CHP Efficiency	Partial Load Performance	Required Level of Gas Cleaning
Internal Combustion Engine	1 - 5,000 [4]	3 [4]	20-36% [5,6]	30-40% [4]	50-76%	Good [9]	Medium
Steam Turbine	2,000 - 5,000 [3]	3 [3]	17% [7]	59%	76% [7]	Poor [9]	Low
Gas Turbine	150 - 5,000 [1]	3 [1]	22-40% [1,9]	40-58%	80% [1]	Poor [9]	Medium
Fuel Cells	0.5 - 5,000 [8]	2 [2]	50% [8]	40%	90% [8]	Good [9]	High
Micro Gas Turbine (recuperated)	< 150 [1]	2 [1]	23-30% [1]	35-52%	65-75% [1]	Fair [9]	Medium
Micro Gas Turbine (unrecuperated)	< 150 [1]	2 [1]	17-20% [1]	50-63%	70-80% [1]	Fair [9]	Medium
Organic Rankine Cycle	200 - 2,000 [2]	3 [2]	8-23% [2]	37-72%	60-80% [2]	Good [3]	Medium
Stirling Engine	3 - 150 [2]	2 - 3* [2]	15-35% [2]	30-70%	65-85% [2]	Good [9]	High
Micro- Turbine	30-1000	2/3	22-28%	38-45%	63-71%**	Fair	Medium

Notes: Efficiencies are given as percentage of input feedstock Notes: Efficiencies are given as percentage of input feedstock heating value, recuperated = compressed air is heated before entering the combustor.

*** Commercially available for natural SEs, but pilot scale for biomass SEs.**

**** The overall efficiencies stated here assume the need for pre-combustion gas compression. Where high pressure gas is available directly from utilities, it is claimed that units can reach overall operating efficiencies of 90%.**

Technological maturity scale: 1=model simulations, 2=pilot scale, 3=commercially available

Sources: [1] Pilavachi 2002; [2] Maraver et al. 2013, [3] Obernberger and Thek 2008; [4] Zogg et al. 2007;

[5] Jung et al. 2015; [6] Lee et al. 2013; [7] Pantaleo et al. 2015; [8] Laporte and Shook 2015; [9] Clarke et al. 2012

The main advantages of microturbines are that they are modular, packaged units that can be easily planned for and installed up to 10MWe, and published case studies indicate that the technology has been demonstrated across a range of applications. They demonstrate operating flexibility and modulation capability, and are capable of fast start to support on-site loads.

The main disadvantage of the technology is that installed costs are still relatively high, although this is partly offset by low maintenance costs. Data on operating lifetime / timing of major overhaul also suggests that it currently is a relatively expensive option. In circumstances where high pressure gas supply is not available, overall operating efficiency is lower than some of the other CHP options. As the technology becomes more widely used and it is proven in a greater range of settings, it is quite possible that it would be an option considered for district energy applications.

4.5.2.9 Augmentation of CHP Operation

Heat-to-Cooling - Absorption Chillers

The transformation of heat to cooling via absorption chiller technology is the primary means of making district heating CHP cost-effective in temperate and warmer climates. Absorption chillers utilize four stages of energy exchange (compression, expansion, evaporation and condensation.) to generate chilled water at appropriate operating temperatures.

There are two variants of absorption chiller technology, 1) single-effect and 2) duel effect. Single effect units utilize low grade heat (typically low temperature hot water at ~130-200°F) as the heat source, and generate cold water at an operating efficiency of Coefficient of Performance (CoP) of 0.65-0.7, where 1 unit of heat generates 0.65 units of coolth. Dual effect units use low- and high-grade heat (typically process waste heat, heat from combustion, or heat recovered from CHP exhaust flue gases at >750°F), and have a typical COP of 1.2 to 1.4. The heat supply temperature to the chiller goes a long way to determining where units are located within the network topology. Single effect units offer the most flexibility as the supply temperatures mean that they can be either collocated with the CHP units, or located remotely within the buildings that they supply, and be connected to the district heating supply. For dual effect plant, for reasons of costs and safety transporting flue gases outside the energy generation site is generally not an option, so they are nearly always connected directly to the CHP unit that supplies them with heat (via at least one heat exchanger). Both single and dual effect units are able to operate at part load conditions, they operate most efficiently under a steady condition.

Absorption technology is mature – it has been utilized in numerous industrial and commercial applications for decades, and is frequently paired with CHP in district cooling applications and is a good fit for both gas engine and fuel cell prime movers. The potential for future deployment will depend in part upon the degree to which CHP is adopted as a distributed energy resource, as the opportunities for direct fired natural gas applications may decline as the focus on reducing carbon emissions intensifies. Absorption cooling is a relatively high capital cost option, although this can be more than offset by high utilization rates. These units also require significant space for the unit and supporting local equipment, and also for the heat rejection / cooling tower capacity that is required to support their use.

CHP Heat-to-Electricity

A CHP configuration that is relatively well developed in the industrial sector is that of 'Bottoming Cycle' CHP, which recovers waste heat from an existing industrial process, and transforms it into electricity (and possibly some further, usable heat). This is typically achieved via a waste heat boiler, which would raise steam, which in turn would drive a turbine.

In recent years, materials science research efforts have advanced the potential for nanotechnology to provide a similar capability, although to date, identifying cost-effective materials and technology configurations have remained elusive. This is largely due to the low electrical conversion efficiency, currently accepted at 5-10% for bismuth telluride-based devices (Kushch 2009, Chen et al. 2010).

New materials or technology configurations developed that increase conversion efficiency or drive down costs could unlock the potential for this technology utilizing CHP heat (assuming high grade heat only) and so it remains possible that this could further support the case for district energy CHP in the medium to long-term.

4.5.3 Retrofitting Gas Boilers for Biogas

The two main modifications that must be made to a natural gas boiler in order to be suitable for biogas combustion are: (1) replacing internal boiler components with stainless steel, and (2) upgrading the controls scheme to tolerate increased variability. The use of stainless steel or other corrosion resistant metals for the interior components of the boiler prevents corrosion and degradation of the boiler. Biogas has a much more variable composition than natural gas, and it is necessary to upgrade the boiler control system to handle this level of variation while maintaining a constant power output. This control scheme upgrade can be simplified or eliminated altogether if biogas is co-fired with natural gas. In this way, there is an additional input variable that can be controlled to regulate the input heating value and flow rate (Landfill Methane Outreach Program).

An additional challenge that exists with burning biogas is the presence of siloxanes. Even in low concentrations, they form a white powder (silicon oxide) when burned. This substance accumulates on the interior of the boiler, and requires cleaning by brushing or water washing.

There have been several successful demonstrations of converting natural gas boilers to combust landfill gas (which is very similar in composition to biogas). Successful case studies can be found in the NASA Goddard space flight center, and the Cone Mills White Oak Plant in Raleigh, NC (Municipal and Industrial Solid Waste Division Office of Solid Waste 1999).

4.6 Technology Compatibility With Feedstock Types

As discussed in Section 4.5, literature on biomass conversion can provide a general sense of whether a type of waste biomass should be processed using thermo-chemical or biological technologies. Key differences between biological and thermal treatment are listed in Section 4.5 and from a technical standpoint, there may be reasons why a facility must chose anaerobic digestion over combustion, or vice versa (Table 40). However, existing literature does not provide a clear picture of what might affect performance, or what might make a type of biomass typically used in combustion an important co-digestion additive to anaerobic digestion (for example, straw). Section 4.6.1 consolidates the findings of literature to improve the understanding of the challenges and decisions an operator might face when matching existing waste feedstocks in California with mature conversion technologies.

Commercially, direct combustion technology has been demonstrated successfully for a wide variety of feedstocks, from dry wood chips to municipal solid waste. Direct combustion is closely related to incineration, which is commonly used as a municipal waste management strategy. To achieve maximum efficiency from a direct combustion system, the feedstock moisture content should be between 5 - 20% by weight. High ash content can lower energy production and is problematic if it is not adequately filtered out of the product gas or if the operating temperature is high enough to affect the ash. Furthermore, the degree of slagging, fouling and corrosion depends upon the chemical composition of the ash. The 2013 paper by Vassilev et al. contains a comprehensive list of high concentration benchmark values. Biomass with high concentrations of K, Na, Cl, S, Si and Ca, low melting temperatures and low viscosity of the melt tend to be the most problematic. The following values are considered "high" mass concentrations for elements present within ash, and are likely to be problematic when used in a thermochemical pathway: potassium (52.8%), sodium (22.1%), chlorine (14.2%), sulfur (10.3%), silicon (44.1%) and calcium (59.8%). For these reasons, it is difficult to assign a general upper limit on the ash content of suitable biomass feedstock for thermochemical decomposition. However, 5% is often given as a benchmark upper limit to minimize problems associated with high ash content. Table 41 shows the prevalence of different energy conversion technologies and disposal options for common feedstock types generated in California.

Table 40: Typical Operation Parameters for Biological (AD) and Thermal (Combustion and Gasification) Conversion Technologies

Parameter	Biological	Thermal
Residence Time	Long (3-60 d)	Short (10 sec - 1 h)
Start-up Time	Long (9-180 d)	Short (20 min - 1 h)
Operational Temp	Low (20-55°C)	High (300 - 1100°C
Operational Complexity	Moderate	Low to high
Potential for Automation	Moderate	Low to high
Preferred Feedstock	Nutritionally balanced, slurried, wet	Dry, minimize potassium, chlorine, sulfur
Residue	Biologically active, slurry and liquid	Dry, sterile ash or char

Sources: Adapted from Vigil and Tchobanoglous 1980.

Table 41: Prevalence of Energy Technologies and Disposal Practices for Significant Biomass Waste Types (Not Including High Strength Wastewater) Generated in California

Primary Feedstocks	Energy Technology			Disposal Practice				
	Combustion	Gasification	AD	Landfill	Sewer	Burning	Burying	Alt Market
Organic Fraction MSW	xxx	xx	xxx	xxx		xxx		
Fats, Oils, Grease (FOG)			xxx	xxx	xxx			xxx
Meat Waste	x	x	xxx	xxx		xxx	xxx	xxx
Bakery Waste			xxx	xxx				xxx
Veg. Fruit Culls and Scraps			xxx	xxx				xxx
Sewage Sludge/ Biosolids	x	xx	xxx	xxx	xxx			xxx
Beverage Waste			xxx		xxx			
Paper Mill Waste	x	xx	x	xxx		xxx		
Orchard Vineyard	xxx	xx	x			xxx	xxx	
Bedding	xx	x	xx	xxx		xxx	xxx	
Nut Shells and Hulls	xxx	xx	x	xxx		xxx	xxx	xxx
Field / Row Crop Reside	xxx	xx	xx			xxx	xxx	
Olive/Fruit Pit Waste	xxx	x	x	xxx			xxx	xx
Cotton Gin Waste	xx	xx	x	xxx				xxx
Rice Hulls/Husks	xxx	xx	x	xxx				xxx

Primary Feedstocks	Energy Technology			Disposal Practice				
	Combustion	Gasification	AD	Landfill	Sewer	Burning	Burying	Alt Market
Dairy Waste			xxx	xxx	xxx			xxx
Manure	x	xx	xxx	xxx			xxx	xxx
Lab-scale studies exist	x							
Pilot projects exist	xx							
Established practices	xxx							

Source: Lawrence Berkeley National Laboratory

Generally speaking, the harsh conditions within a gasification reactor can thermally decompose most biomass feedstocks. However, limits should be placed on the moisture and ash content of feedstocks to ensure efficient operation of gasification processes and to protect the reactors and other equipment.

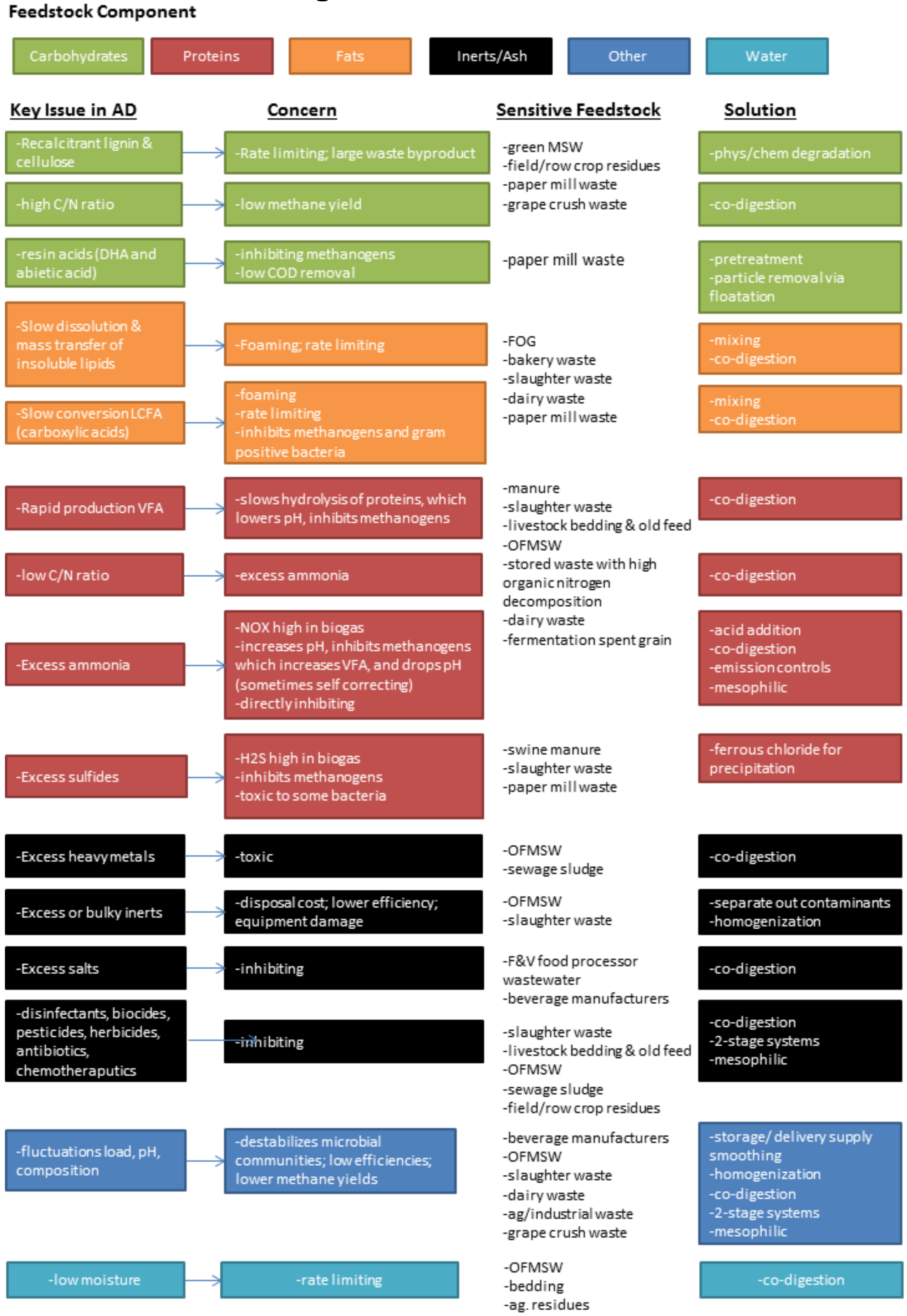
Due to the nature of microbial decomposition reactions, anaerobic digestion requires a moist environment for operation. Biomass feedstocks with moisture content of greater than 55% by weight are generally best suited for AD. Industrial wastewaters with high COD content are best suited for thermophilic AD; all other high moisture feedstocks are better suited towards mesophilic AD, which has more diverse microbial communities and is less sensitive to fluctuations in the feed. Balancing carbohydrates, fats, and proteins, (often just represented as carbon, nitrogen, phosphorus, and other nutrient ratios) in the feedstocks entering the AD system is essential for sustaining microbial communities and enhancing methane production.

4.6.1 Demonstrative Waste-to-Energy Operation Challenges

Figure 12 shows the challenges that can occur in AD systems (wet or high-solids) that is loaded with a protein, lipid, or carbohydrate rich substance (Li et al. 2002). Other common issues that cause inhibition in wet AD systems include: volatile acid build up, sulfides, or high levels of alkali or alkaline earth metals, ammonia, or heavy metals (Stronach et al. 1986). Figure 12 and Figure 13 map the challenges and decisions an operator might face when matching existing waste feedstocks in California with AD and combustion, respectively. Unique fuel characteristics/components are listed that have resulted in issues for power plants or in literature. These components or characteristics are then mapped to feedstocks of significance in California. The type and availability of solutions for each issue give a sense of whether associated efficiency losses or costs can be overcome in the near future.

For example, Figure 12 shows the potential issues that can arise from feedstocks that are protein, carbohydrate, or lipid rich. Dairy wastes, manure, and food wastes appear to be high suitable for AD without co-digestion based on composition balance and performance at facilities. That said, even these materials can generate more consistent or higher methane yields with co-digestion. This is an active area of research.

Figure 12: Considerations for Matching Feedstocks with AD Based on Potential Challenges and Available Solutions



Source: Lawrence Berkeley National Laboratory

Figure 13: Considerations for Matching Feedstocks with Combustion Based on Potential Challenges and Available Solutions

Feedstock Component

C:H:O | N | Ash | Other | Water

Key Issue in Combustion	Concern	Sensitive Feedstock	Solution
-high lignin or cellulose, and K species	-soot / smoke formation	-green MSW -orch/vine prunings -C&D wood -wood bark -olive husks	-physical/chemical degradation
-high fixed carbon	-affects ease of ignition, rate of heating and temperature		
-high volatile matter	-rapid burn hard to control -emissions of CO, PAH, and hydrocarbons	-green MSW -field crop residues -paper mill waste -mixed paper -olive cake and pits -pellets from ag. residues or wood	
-low volatile matter	-difficult to ignite and burn	-dry cattle manure -poultry manure -fruit& veg. pulp	
-low HV	-low combustion temperature		
-Nitrogen	-NOx (near linear relationship with N content) and N2O emissions	-straw (esp. rice, wheat -rice husks -green MSW -orch/vine prunings -C&D wood -sewage sludge -bone meal	-air stagging in fluidized bed to control Nox -combust at lower temperature -torrefaction pretreatment
-High ash concentration	- low energy yield - limits char combustion	-rice husks -straw & grasses -almond hull and shell -green MSW -cattle manure -sewage sludge -row crop waste	-washing leaching to reduce fuel-bound elements
-low melting temperature of ash (e.g. high K2O)	-ash sintering and bed agglomeration		
-Potassium & Sodium (and other alkali metals)	-salts and inorganic aerosols KCl, NaCl -reacts with silica in moderate to high temperatures to form severe slagging (alkali silicates) -reacts with sulfur to form alkali sulfates that deposit on surfaces -potassium can promote char combustion which is a benefit	-straw (esp. rice, wheat -rice husks -green MSW -orch/vine prunings -C&D wood	
-Chlorine (and other halides)	-HCl emissions -facilitates mobility of inorganic compounds like potassium	-herbacious waste	
-Sulphur	-SO2 emissions; H2S	-rice straw and hulls -bone meal	-inject lime or limestone to capture SO2
-biogenic silica	-fibrous PM a health hazard	-rice straw and hulls	
-heavy metals	-affects ash disposal	-OFMSW -biosolids/sewage sludge -manure -soil contaminated ag. waste	
-geometrical shape, porosity, tendency to fragment	-lower combustion temperature -challenging fuel loading conditions/low bulk density -affects fuel/air ratio	-hulls/husks -sawdust -grain chaff	-phys/chem pretreatment -densification
-fluctuations load, composition	-destabilizes microbial communities; low efficiencies; lower methane yields	-ag/food processor -OFMSW -green MSW	-storage/ delivery supply smoothing -homogenization -co-digestion -2-stage systems -mesophilic
-tar production (often heavy hydrocarbons and heavy metals)	-tar in the gas -equipment failure	-field/crop residues -OFMSW -C&D wood	--emissions scrubbing
-Moisture	-poor ignition -incomplete combustion (CO emissions) -excess flue gas requiring larger gas treatment equipment	-green MSW -ag/industrial waste -grasses and soiled field residues -food processor waste (pits) -manure	-drying

Source: Lawrence Berkeley National Laboratory

For thermochemical pathways like combustion and gasification, the main distinctions between low moisture feedstocks including woody, herbaceous, and MSW (paper, wood, green waste) types is the composition of hemicellulose, cellulose, and lignin, and the concentration and composition of the ash and inorganics. The elemental analysis of carbon, oxygen, and hydrogen are very similar among these low moisture waste types. Contamination due to dirt, and the inherent inorganic matter dispersed throughout the material can drive the level of ash fouling and slagging, the quality of the ash, and production of inorganic aerosols. The ratio of hydrogen to carbon is an indicator of the amount of fuel consumed during pyrolysis; biomass are characterized as loosing much of their mass (75-90%) during this stage, compared to coal which loses <65% during this stage (Jenkins et al. 1998). While there are some indicators of the amount of fouling and slagging that may occur during combustion, such as the alkali index (whether there are enough forms of alkali to completely react with the chloride and sulfate inherent in the fuel) and the base-to-acid ratio of the fuel ash, there are no perfect estimates (Jenkins et al. 1998). The energy content has been correlated with the ash content, or carbon content, but again, these are rough approximations. The higher the hydrogen carbon in the carbohydrate and lower the oxidation the higher the heating value (lignin has higher heating value than cellulose for example). Jenkins et al. emphasizes that a low heating value does not necessarily mean a low combustion quality or efficiency. A high flame temperature is dependent on both the heating value and the composition of the feedstock.

It is assumed that following the upgrading of biogas to a specific quality, the handling and applications of that biogas are no longer unique to the original feedstock and therefore do not need additional discussion than what is provided elsewhere in this chapter.

CHAPTER 5: Cost and Environmental Assessment, Feasibility, and Regulatory Compliance

5.1 Introduction

Estimating the environmental costs and benefits of organic waste-to-energy systems requires an analysis of the energy and material inputs required to convert organic wastes to valuable forms of energy and to deliver that energy to end uses. Metrics such as carbon or air pollutant intensity per unit of energy can then be evaluated for the potential life cycle. The impact of a system can be understood by estimating net costs and benefits resulting from deployment, which can only be calculated if the potential system is compared with a baseline scenario for future organic waste management. This requires knowledge regarding existing and likely future management practices, and their associated environmental impacts. In this Chapter, the Techno-economic Analysis (TEA) and Lifecycle Assessment (LCA) methodologies and results are presented for organic waste-to-energy scenarios. These scenarios are developed using data from the previous chapters and capture differences in potential feedstock, logistics, conversion/generation technologies, emission controls and cooling systems. Illustrative results of the TEA and LCA capabilities developed by the project team are presented. Existing and potential policy and regulatory compliance and impact issues are provided at the end of the chapter. A sensitivity analysis is presented for lifecycle greenhouse gas.

5.2 Lifecycle Energy and Greenhouse Gas Assessment

5.2.1 Scope and Literature Review

Goal and Scope Definition

In the context of this study, the relevant lifecycle stages include transportation of waste to the facility, waste sorting, anaerobic digester operation, CHP operation, flaring, biofilter, electricity generation (if applicable), outbound transportation of by-products and any possible soil amendment. The functional unit is defined as one tonne of inbound waste.

Life Cycle Inventory (LCI)Ddevelopment:

For this assessment, unit emission rates and emission factors are collected for all lifecycle stages involved. This data is derived from field measurements at pilot facilities in California, the GREET model (Wang 2001), literature reviews, and existing LCI databases including Ecoinvent (Frischknecht et al. 2005; Frischknecht et al. 2007; Wernet et al. 2016).

Past LCA studies have examined stand-alone waste-to-energy systems (Scipioni et al. 2009; Møller et al. 2011; Turconi et al. 2011; Tonini et al. 2013; Boesch et al. 2014) as well as entire waste management systems that include energy recovery (Finnveden et al. 2005; Moberg et al. 2005; Eriksson et al. 2007; Finnveden et al. 2007; Rigamonti et al. 2014; Christensen et al. 2009; T Fruergaard et al. 2010; Thilde Fruergaard et al. 2010; Bernstad and la Cour Jansen 2011; Manfredi et al. 2011; Tunesi 2011; Merrild et al. 2012; Song et al. 2013). Anaerobic digestion with energy recovery, as well as thermochemical conversion technologies, have consistently been shown to reduce GHG emissions relative to landfilling organic waste (Lombardi et al. 2015; Sadhukhan and Martinez-Hernandez 2017).

Among various feedstocks, gasification of crop residues has been reported promising source of energy owing to its higher energy yield compared to direct combustion (Yang and Chen 2014). The study further reported GHG mitigation benefits from crop residue gasification technology. Gasification of willow biomass has been reported to increase net energy ratio (production over consumption) by over 9% and reduction in GHG emission by 7-10% (Heller et al. 2004). However, prior to large scale implementation of biomass gasification, it is imperative to investigate environmental performance of various feedstocks with respect to their energy yield to be able to shed light on sustainable technologies (Yang and Chen 2014).

This project assumes waste-to-energy projects divert technically available waste organics from landfilling, composting, and open burning (assumptions are biomass type-specific). Composting is already employed for some organic wastes (e.g. yard waste) and allows stabilization of organic waste through anaerobic decomposition, but emits air emissions, namely; NH_3, N_2O, CH_4, SO_2, CO and odor (Amlinger et al. 2008; Boldrin et al. 2009; Saer et al. 2013; CEPA 2017). Composted organic wastes, can be used to displace industrial-sourced fertilizer if applied to croplands (Favoino and Hogg 2008; Martínez-Blanco et al. 2009; Martínez-Blanco et al. 2013). However, environmental impacts and benefits associated with the land application of composted waste organics varies significantly by soil type, crop type, and composting process, and is a source of uncertainty (Martínez-Blanco et al. 2009).

5.2.2 Lifecycle Environmental Assessment Methods

This LCA model is based on the conversion facility cost model that utilizes a site-level cost and optimization scheme (Section 5.3.1). For a given site, the model assesses the available feedstocks within a defined maximum distance and calculates the associated environmental impacts of building different types of facilities at different scales. The model aggregates the total amount of biogas or biomethane produced, the total waste processed and the byproduct, for the types and sizes of facilities built. This process is conducted for electricity, biogas, and biomethane generation separately over a range of energy price levels for the years 2020 and 2050. Figure 16 gives an example system boundary for analyzing a set of projects using anaerobic digestion and gasification to convert feedstocks into electricity, biogas/syngas, or biomethane. In the conversion facility cost model, municipal food waste, high moisture agricultural residues, food processor high moisture solids, and fats oils and grease are allocated to anaerobic digesters. Table 42 provides feedstock classifications for conversion technology based on the price level. Low moisture agricultural residues, food processor low moisture residues, and municipal lumber, paper, cardboards, and green waste are allocated to gasification in 2020 and 2050.

In the scenarios, daily shipments of incoming organic wastes are transported via diesel trucks. Wastes are then cleaned and preprocessed (reflected only as an additional cost in the TEA model), and fed into the facility's conversion technology. Type of waste, location of waste source, and annual quantity of waste in California for the year 2020 is obtained from the biomass inventory portion of this study. A flatbed trucking is assumed for the pickup and delivery of waste from waste generation sources to the AD/ gasification facility. Transportation distances from the waste source to the facility is calculated based on site-level cost and optimization model (Section 5.3.1). Emissions from natural gas and diesel used in transportation include CO_2, CH_4, N_2O, NO_x, SO_2, CO, NMVOC and $PM_{2.5}$ and are sourced from GREET model. Dry anaerobic digesters are assumed to have a total solids loading rate of 22 to 40% (Ward et al. 2008), and can be modeled as airtight chambers to which micro-organisms are added via sprinklers (Di Maria et al. 2017). Electricity required to operate an existing dry AD facility (ZWEDC) is used to represent energy consumption for pre-inspection, sorting and operation of all the dry AD facilities in this study. Electricity consumption to operate dairy and WWTP AD facility are minimum and are not considered in this study. Finally, electricity required to operate a stand-alone wet AD facility is approximated using values adopted from the UC Davis's Renewable Energy Anaerobic Digester (READ) Facility. Emission rates measured by members of the project team at a dry-AD facility in California are assumed for combined heat and power generation from biogas combustion, biogas flare and fugitive emissions from organics composting. These emissions are assumed to be representative for the same processes at dry AD, wet AD, dairy AD and codigestion at WWTP AD facilities. Finally, emissions at gasification facilities are sourced from California Environmental Protection Agency, Air Resource Board report (2014). The construction lifecycle phase of waste-to-energy facilities is not considered owing to its minimal impact when normalized over the facility life cycle.

Once the transportation distances (inbound and outbound), biogas produced, flared, vented, electricity produced, offset for fertilizers, carbon storage and electricity produced are estimated, the emission rates collected from literature, the Ecoinvent database, the GREET model and direct on-site measurements are used to estimate lifecycle environmental emissions (CO_2 eq, NO_x, NMVOC, SO_2, CO and $PM_{2.5}$) assuming 20 years life time of the facility. Greenhouse gas emissions and carbon sequestration from biochar application on cropland and rangeland are estimated based on the labile and recalcitrant carbon content expected in biochar generated from specific feedstocks (methodology pending in Breunig et al. 2019). Biochar yields for the gasification of various feedstocks included in this study are presented in Table 42. Use of digestate as fertilizer not only replaces inorganic fertilizers but can result in higher nitrogen use efficiency by crops and increased soil organic matter (Tambone et al. 2010). Previous studies suggest that applications of digestate and biosolids can increase soil organic carbon (Brown and Leonard 2004), however turnover of carbon may be too fast to warrant long term carbon sequestration. Unlike digestate, biochar does not replace fertilizer, but the carbon content of biochar gets sequestered in the soil post its application. Emissions from digestate application on cropland and rangeland are estimated based on representative emissions profiles for raw or composted digestate on California soils (Silver et al. 2018). Additional details on the byproduct disposal lifecycle are available in a pending journal article by Breunig and colleagues. Recalcitrant carbon content of some waste such as food waste, wood, paper, yard waste does not degrade even after landfill, rather gets sequestered in the landfill offsetting up to 7.5% of the methane emissions from landfill (USEPA 2018). Therefore, methane emissions from landfill are estimated considering the carbon sequestered by the landfill. Biogenic CO_2 emissions from sources such as composting, landfill gas flare, biogas combustion and biogas flare are not taken into account while estimating emission rates.

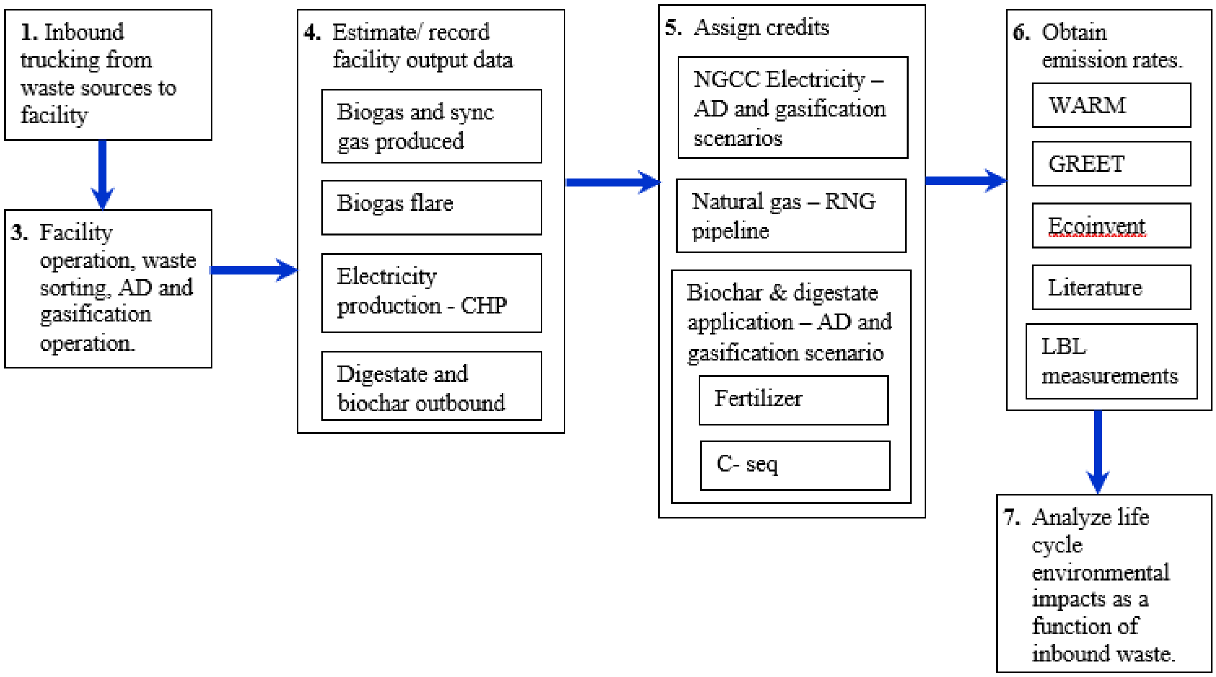
Finally, to interpret the results, lifecycle environmental impacts are analyzed as a function of inbound waste (Figure 14). This means that results cannot be compared on a per-tonne waste conversion basis, rather they are the total impact of a scenario divided by the total tonnage treated per year. As the tonnes of materials diverted to bioenergy vary by price point and end use (electricity, biogas, or biomethane), it is important to keep the LCA functional unit in mind. Starting out with the idea that amount of energy produced is directly related to the amount of waste entering the waste management facility, functional unit of “Emissions per tonne of inbound waste” is selected.

Table 42: Biochar Yield for Various Feedstocks

Biomass Residue	Proxy	Reference	Biochar Yield @ 1025	Biochar Yield @ 778	Biochar Yield @ 477
Cardboard	wood	Ronsse et al 2013	17%	20%	29%
Field crops unsp.	corncob	Demirbas 2004	4%	13%	24%
Field other	corncob	Demirbas 2004	4%	13%	24%
Forest slash	wood	Ronsse et al 2013	17%	20%	29%
Forest thinning	wood	Ronsse et al 2013	17%	20%	29%
Fruits & nuts unsp.	palm oil empty fruit bunch	Claoston et al 2014	13%	17%	27%
Green	wood	Ronsse et al 2013	17%	20%	29%
Lumber	wood	Ronsse et al 2013	17%	20%	29%
Olive	olive husk	Demirbas 2004	7%	26%	39%
Paper	wood	Ronsse et al 2013	17%	20%	29%

Source: Lawrence Berkeley National Laboratory

Figure 14: Schematic Representation of Conceptual LCA Model



Source: Lawrence Berkeley National Laboratory

5.2.2.1 System Boundary and Scenarios

BAU (Landfill, Compost and Burning Residues)

A BAU scenario assumes the state's technically available biomass residue resource is either landfilled, composted, or burned. In this scenario, all MSW is sent to landfill. Emissions from landfill include the emissions from trucking of waste from city facilities as well as the emissions from the landfill. A flatbed truck that uses diesel is assumed for the waste pickup and delivery. Trucking emissions include emissions from diesel production as well as diesel combustion. Landfill gas is modeled as roughly 50% methane. The EPA (WARM) model is used to estimate GHG emissions from landfills.

A fraction of orchard and agricultural field residues are assumed to be burned in piles on the field ("open burning"). This fraction is set at 30%, and varied in a sensitivity analysis. Emission from burning (mainly CO_2 and CH_4) are sourced from IPCC guidelines for managed soils (2006 IPCC Guidelines for National Greenhouse Gas Inventories).

All waste except MSW, and a fraction of orchard and field residues, are modeled as being sent to compost facilities which generate compost that is then applied to the soil as a partial fertilizer replacement. Emissions from composting include methane emissions from organics composting, emissions from direct application of compost and carbon-sequestration from the land application of compost. A similar flatbed trucking is assumed for the pickup and delivery of waste from city facilities to the compost facility. Transportation distances from the waste source to the facility is calculated based on site-level cost and optimization scheme (Section 5.3.1). After further treatment and dewatering, final compost can be applied as fertilizer. Assuming 5.5% N (Sullivan 2015) content in the compost, the amount of urea fertilizer (46% N) replaced by 1 kg of compost is estimated. Many studies indicate that when the compost is dewatered, 33% of the mass is removed in the liquor fraction. This is a key source of uncertainty in the model as it affects the weight and volume of materials requiring transportation, and should be investigated further in future studies. As CO_2 emissions from compost are biogenic, these emissions are not regarded as contributing to a systems lifecycle greenhouse gas emission.

Conversion

Starting out with the idea that biogas and biomethane that can be produced throughout California at various price levels by utilizing the biomass inventory data and information regarding waste tipping fees, expected biogas yield, and facility capital and operational costs, associated environmental impacts are estimated for various price levels (high and low). The model assumes five waste to energy conversion facility types: dry AD, wet AD, dairy AD, co-digestion at existing wastewater treatment AD and gasification. For example, wet AD is limited to accepting liquids and high moisture solids, while dry AD cannot accept liquids but can accept low or high moisture solids. Gasification system accepts wastes such as field residues, low moisture solids, lumber and green waste. Wastewater and dairy AD facility are specific to co-digestion of wastewater sludge and dairy respectively.

Methane yield is feedstock- and facility type-specific, and can vary significantly across waste types. AD byproduct (digestate) is assumed to be sent to nearby farms for land application to offset fertilizer requirements. Gasification byproduct (biochar) does not replace fertilizer, and is modeled as being used as a soil amendment on marginal lands for carbon sequestration purposes. Digestate from dry AD is dewatered, 20% of the mass is removed in the liquor fraction, leaving a dewatered cake of approximately 80%. In the case of wet-AD, the dewatered cake is only 20% of the initial mass. Dairy and WWTP AD systems are also assumed to produce digestate with 20% dewatered digestates for land application. In this preliminary analysis, the carbon sequestration ability of biochar is estimated by assuming 90% carbon content of biochar, of which 100% gets sequestered in soils. In reality, a fraction of carbon in biochar is labile and will be emitted as carbon dioxide in the first 100 years. A detailed analysis of biochar and digestate carbon sequestration potential and net greenhouse gas emissions is available in a pending journal article by Breunig and colleagues.

Biomethane Production and Pipeline Injection

Biogas is treated to remove moisture, particulates, contaminants and other gases (such as CO_2, O_2, N_2 and VOC's); this increases the methane content to 90% or more, depending on the upgrading technology. Upgraded biogas with methane content more than 96%, referred as renewable natural gas (RNG) can be used for pipeline injection. Use of RNG as fuel reduces consumption of natural gas which would otherwise be used in absence of RNG. In the state of California, RNG is now being considered as an important energy product of anaerobic digestion facilities, to be used as a vehicle fuel or potentially be injected into existing or extended natural gas pipelines. As of 2018, there are around 50 landfill gas to RNG facilities in operation, of which mostly produce RNG as vehicle fuel. To the research team's knowledge, there is only one RNG pipeline injection facility in operation - the Point Loma Wastewater RNG project developed by BioFuels Energy, LLC.

Conversion of biogas to biomethane, as described in Chapter 4 is highly energy intensive and processes vary in the literature. A membrane separation technology is assumed in these scenarios owing to its relative maturity, low cost, energy efficiency and least loss of product. With no heat consumption in the upgrading process, an electricity consumption of 0.18-0.20

kWh/m3 is assumed for raw biogas upgrading while, clean biogas required 0.14 to 0.26 kWh/m3. Average loss of less than 0.6% loss is assumed during the upgrading process with almost 98% purified biomethane (Angelidaki et al. 2018). Starting out with the idea that upgraded biogas can also be used as renewable pipeline-injected natural gas, bio-CNG was assumed to offset natural gas via existing commercial pipeline located 1 mile away from the site. An average of 1 mile of pipeline is assumed for the pipeline injection to the existing commercial natural gas distribution system. Owing to the fact that pipeline construction has minimal impact on the lifecycle stages, its construction is omitted from the study. The end use of natural gas, which is natural gas combustion, is not applied to pipeline scenario offset, as it cancels out with the biomethane combustion assuming they have similar properties.

Emitted and Avoided Emissions from District Energy Networks

Operation data for district energy networks in five regions of California were evaluated for their emissions based on fuel consumption and operation hours. These systems were compared with a base case where energy consumption is met with the electricity grid and natural gas boilers. For each region, networks are assumed to be powered by syngas, biomethane, or biogas CHP units using either spark ignition gas engines (SIGE) or fuel cells. Direct emissions from these systems are calculated, as are emissions from any additional grid electricity (for the chiller or HP) or natural gas consumption in boilers to meet expected network energy needs. These operation parameters are calculated using the models presented in Section 5.3.2. Similar to the LCA model, a 2050 grid mix is assumed for electricity. Carbon dioxide emissions from the use of syngas, biogas, and biomethane are assumed biogenic, while CH_4 and N_2O are accounted for. Air pollutants included NO_x, $PM_{2.5}$, SO_2, NMVOC, and CO are also evaluated to explore the effects of decisions at the network, and get perspective beyond the waste-to-energy facility. In this preliminary comparison the emissions from biogas in SIGE and fuel cells are assumed to be double that of biomethane. Emission factors from a facility in San Jose California suggest substantial methane emissions can come from CHP systems using biogas, resulting in order of magnitude increases in GHG emissions from these systems. As such, sensitivities in emissions factors should be carefully explored and verified through measurements and monitoring. Results of this analysis for GHG are presented in the Introduction in Figure 1; additional results for emissions are pending in an article by Smith and colleagues.

5.2.2.3 Sensitivity Analysis Methodology

In the sensitivity analysis, the effect of 10%, 50%, and 200% changes are explored in key emission factors on net GHG emissions in each of the 2020 scenarios. Emission factors associated with the largest emission sources in the base case results for each scenario are selected. This method is used rather than applying a distribution in emission factors as identified in existing literature, as a starting point. This method is useful for identifying nonlinearities in complex models, which guides future efforts to improve data inputs. The sensitivity analysis only affects values in the lifecycle model, and therefore does not have an effect on the amount of waste being processed and diverted towards electricity generation, RNG production, or conventional waste disposal methods (as determined by the TEA model). Following these variations, assumptions more aligned with hypothetical future conditions are explored. These include an increase in gas leakages from natural gas pipeline infrastructure, an increase in methane generated from biomethane upgrading, and an increase in electricity generated from biogas (Table 43).

Table 43: Variations in Parameters Explored in the Sensitivity Analysis in Addition to Modifying Emission Factors

Contributor	Positive Change	Negative Change
Electricity generated	Total electricity generated (kWh) increased by 5%	Total electricity generated decreased by 5%
CNG loss	Percent loss of methane changed to 0%	Percent loss of methane changed to 4%
RNG generated	Volume of CH_4 generated for RNG increased by 5%	Volume of CH_4 generated for RNG decreased by 5%

***Percent loss of methane in the original model is assumed to be 2%**

Source: Lawrence Berkeley National Laboratory

Three statewide scenarios are included, and base case emission values from key processes, as found in the LCA, are presented in Table 44.

Table 44: Key Parameters for Three Statewide Scenarios Evaluated in the Sensitivity Analysis: BAU, Electricity/High and RNG/High

	Business As Usual (kg CO_2eq/tonne of waste)	Electricity/High (kg CO_2eq/tonne of waste)	RNG/High (kg CO_2eq/tonne of waste)
Agricultural Residue Burning	39.11	13.39	39.11
Biochar Application	0	-13.9	0
Chemicals	0	0	0
CHP	0	1.49	0
Compost Application	-73.56	-65.56	-73.05
Diesel	0.25	0.27	0.18
Digestate Application	0	- 4.86	-7.51
Fertilizer Use	-14.71	-14.62	-16.94
Gasification	0	0	0
Landfill	138.07	36.61	74.85
Methane Loss	0	0	4.93
Natural Gas	-3.17	-7.15	-22.16
NGCC Electricity	0	-22.51	0.30
Organics Composting	43.10	38.42	42.80
Other Electricity	0	-6.76	-7.99
Petroleum Products	0.42	0.46	0.30
Transportation	-1.74	-4.12	-2.79
Net	121.19	-0.56	32.03

Source: Lawrence Berkeley National Laboratory

5.2.3 Results

5.2.3.1 Lifecycle Greenhouse Gas Emission Results

This section presents illustrative results of the lifecycle inventory for a set of scenarios modeled in the waste conversion facility siting tool (as described in Section 5.3). Scenarios are modeled that evaluate the fate of all technically available biomass residues in the state. For both scenarios modeled (a low and high energy price point), a fraction of residues would continue to be landfilled. Despite a significant amount of waste diversion in these scenarios, landfilling is the largest contributor to lifecycle GHG emissions (Figure 15, Figure 16). Compost application, fugitive emissions from organics composting and agricultural residue burning are following contributors, and highly sensitive to assumptions regarding the BAU case.

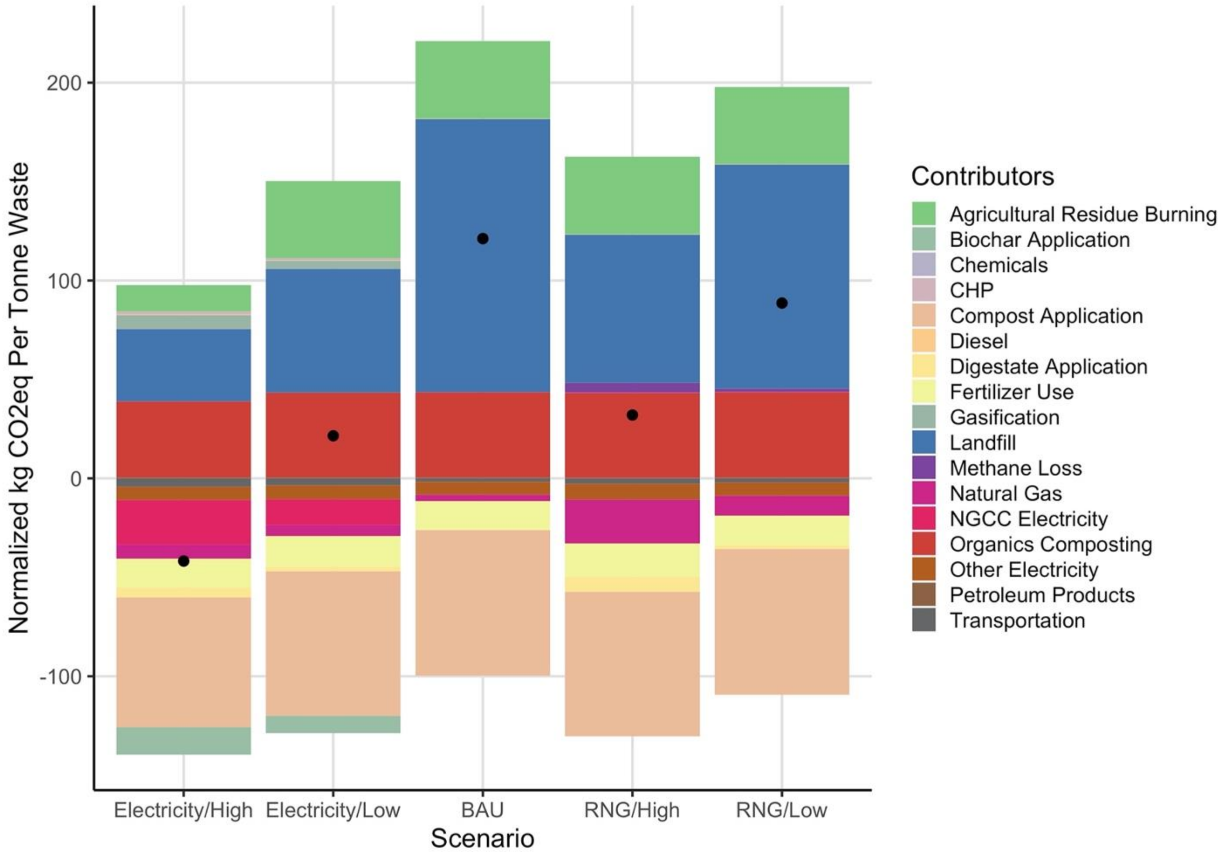
To the team's surprise, relatively similar emissions from compost application as well as organics composting are noted in all three scenarios, as similar amounts of organic waste are composted in each of the scenarios, suggesting the build-out of anaerobic digestion waste-to-energy projects is not sensitive to energy price point in the ranges evaluated.

However, as expected, at the high energy price point, more waste (primarily orchard and field) is diverted from burning to gasification, resulting in less net GHG emissions than the low price point scenario. As higher amounts of orchard and field wastes are diverted from burning and gasification, more natural gas consumption is avoided, resulting in higher natural gas offsets. Impacts from transportation of waste to its designated treatment facility are minimal. Finally, "other electricity" refers to the upstream energy needs associated with urea production, which is avoided when digestate land application offsets urea fertilizer use.

Four offsets are captured in this analysis: electricity generation from biogas or syngas, fertilizer offsets from digestate application, carbon storage from compost, digestate and biochar application and natural gas offset (Pipeline scenario only). NGCC electricity refers to the electricity credit from the conversion technology. Electricity that is generated via waste-to-energy conversion offsets electricity that would have otherwise been generated at a natural gas power plant, the primary source of electrical energy in California. Conversion technology at the higher price have more NGCC credits as more biomass is used in the conversion process. CO_2 emissions from the combustion of biomethane (which would have otherwise been seen as natural gas offset) is considered biogenic and therefore not included in LCA metrics.

In the high price point scenario, higher electricity generation and higher carbon-sequestration from biochar application as well as lower emissions from landfill and reduced agricultural residue burning led to a net reduction in greenhouse gas emissions (Figure 15). The BAU scenario with partial landfill, partial composting, and partial burning has the highest net emissions among the considered scenarios. Carbon sequestration from landfills is accounted for but not visible in the plots as net landfill emissions are positive once fugitive methane is accounted for. Emissions from landfills can further be reduced if landfills use a gas turbine to generate electricity instead of flaring the landfill gas, which would provide a small electricity credit (but would not eliminate all fugitive emissions).

Figure 15: Lifecycle GHG Emissions from Various Waste Management Options - 2020

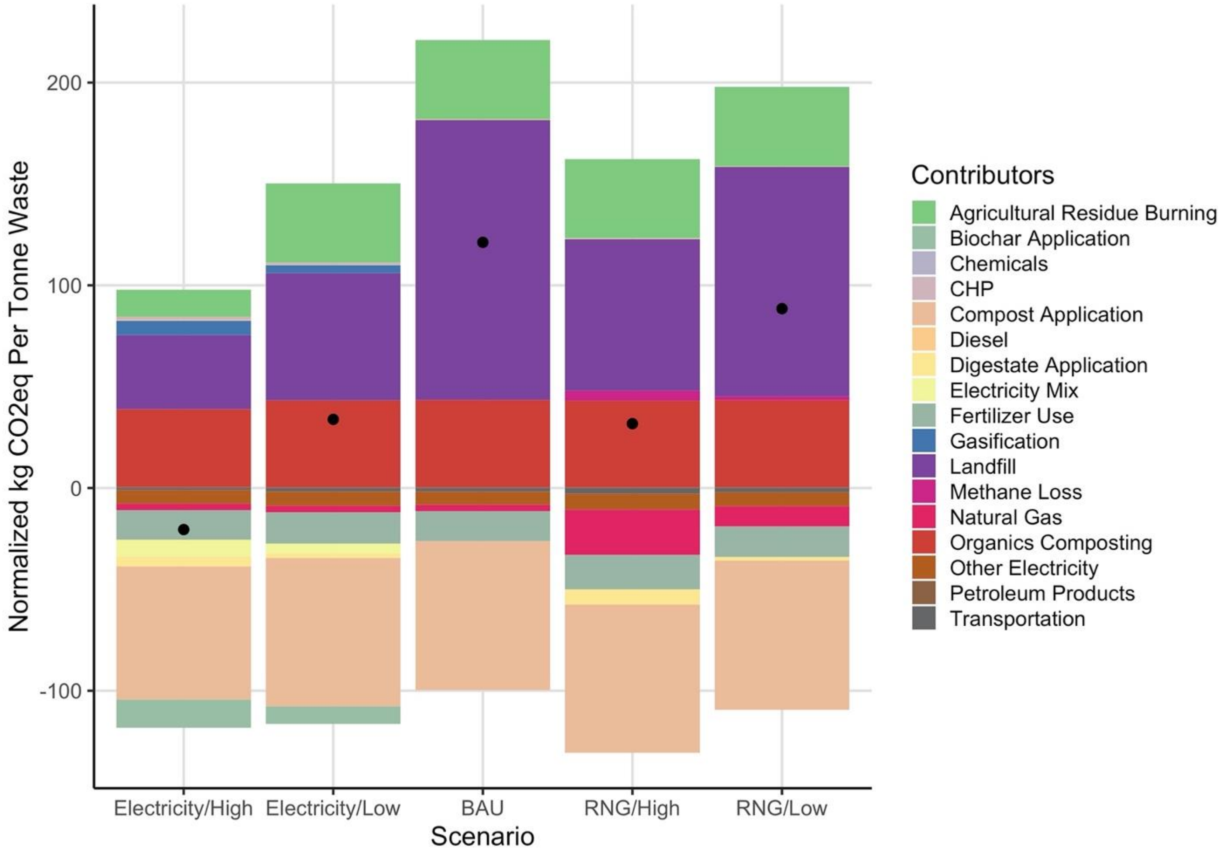


The black dot indicates net emission rate for a given scenario.

Source: Lawrence Berkeley National Laboratory

The net GHG emissions from conversion of the total technical waste stream available for the year 2050 increased (Figure 16). For the year 2050, an electricity grid mix of 60 percent renewables and 40 percent NGCC electricity is assumed owing to California’s target towards renewable energy. Therefore, offsets from electricity reduced significantly from 2020 to 2050.

Figure 16: Lifecycle GHG Emissions from Various Waste Management Options - 2050



The black dot indicates net emission rate for a given scenario.

Source: Lawrence Berkeley National Laboratory

5.2.3.2 Sensitivity Analysis – Carbon Dioxide Equivalents

A 10 percent decrease in the methane emission factor for composting organics led to a decrease in emissions, specifically from composting, of 9.7 percent in all three scenarios (Table 45). This change in emissions from composting contributed to very different percent changes in net emissions from each scenario (ranging from less than 5 percent in the BAU case to 700 percent in the Elec/High case). This is due to the relatively small net emission value in the Electricity High Price scenario and the difference in proportions of CO_2eq and their sources across scenarios.

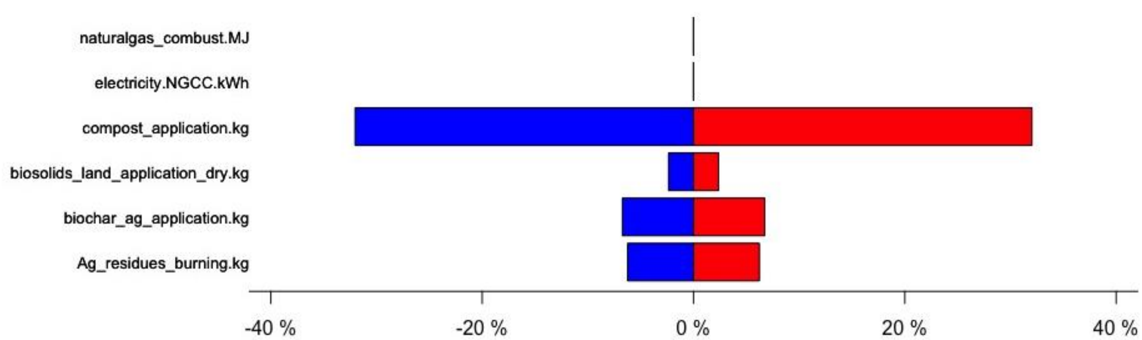
Table 45: Sensitivity Data Describing Impact of 10 Percent Decrease in Composting Emission Factor on GHG Emissions in the BAU, Electricity/High, and RNG/High Scenarios

Scenario	Original value for kg CO_2eq/tonne from Organics Composting	kg CO_2eq/tonne from Organics Composting when reducing factor by 10 percent	Percent change in kg CO_2eq/tonne from Organics Composting	Percent change in net kg CO_2eq/tonne
BAU	4.31E+01	3.89E+01	-9.7%	-3.4%
Electricity/High	3.84E+01	3.47E+01	-9.7%	-18.1%
RNG/High	4.28E+01	3.87E+01	-9.7%	-12.9%

Source: Lawrence Berkeley National Laboratory

The results from the initial LCA show that the most favorable scenario is Electricity High Price, with net negative lifecycle GHG emissions. Following the variation in methane leakage from pipelines, methane generation from biogas upgrading, and electricity generation from biogas CHP systems, these results indicate that even if RNG generation can be improved and methane loss/leakage can be reduced (even to 0 percent), the Electricity/High situation is more favorable (Figure 17). That said, substantial improvements to the RNG scenario can be made, while substantial improvements to the Electricity/High Price scenario are more difficult. For example, a 15 percent improvement in RNG/High net GHG emissions results in a reduction of 4.8 kg CO_2eq/tonne of waste while a 300 percent improvement in Electricity/High net GHG emissions means a reduction of 1.7 kg CO_2eq/tonne of waste.

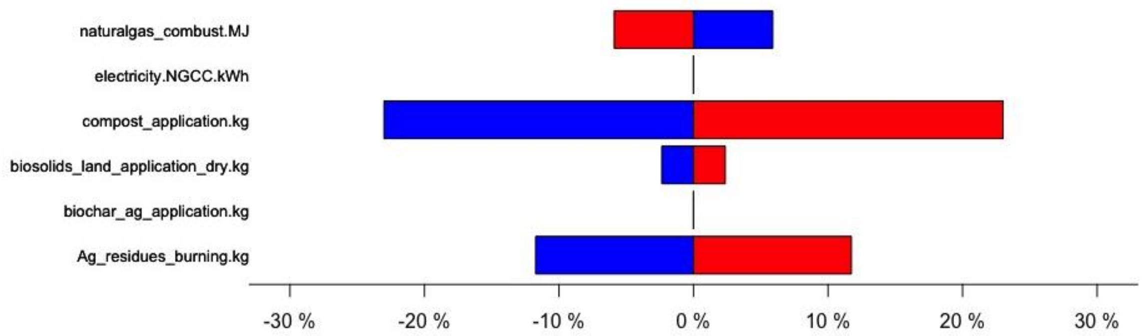
Figure 17: Sensitivity Analysis of Energy Generating Processes in the 2020 Electricity/High Scenario



The y-axis represents percent change in net lifecycle GHG emissions for a given scenario due to a change in a specified parameter or process. The red bars represent positive changes and the blue bars represent negative changes as explained in Table 43.

Source: Lawrence Berkeley National Laboratory

Figure 18: Sensitivity Analysis of Energy Generating Processes in the 2020 RNG/High Scenario



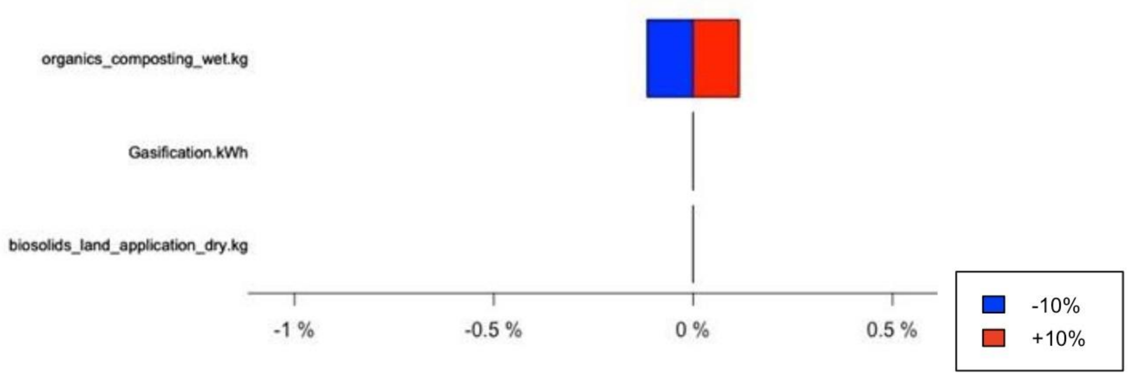
The y-axis represents percent change in net lifecycle GHG emissions for a given scenario due to a change in a specified parameter or process. The red bars represent positive changes and the blue bars represent negative changes as explained in Table 43.

Source: Lawrence Berkeley National Laboratory

Sensitivity of BAU Scenario

Varying direct carbon dioxide emissions from the application of compost on lands and from open burning of low moisture residues on farms, followed by methane emissions from the composting of organics and the landfilling of food waste and other organics, had the greatest impact on lifecycle GHG emissions in the BAU scenario. Results in Figure 19 and Figure 21 reflect a 10 percent change in parameter values; no significant nonlinearities are identified.

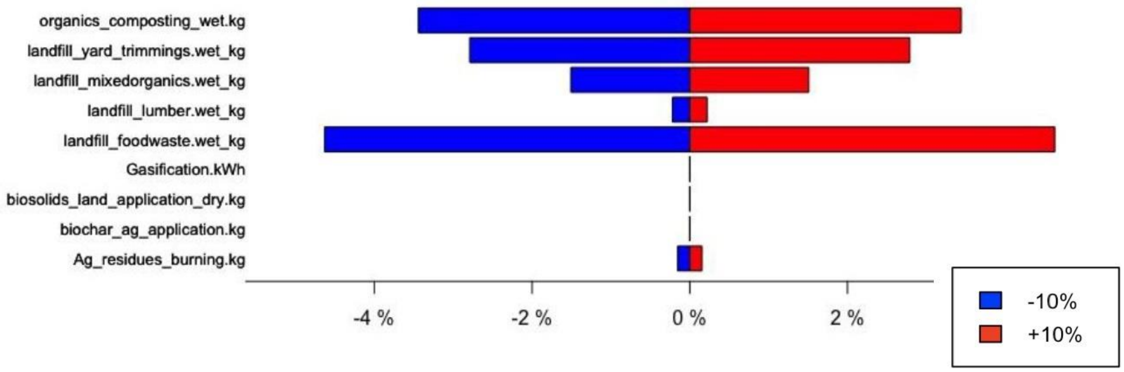
Figure 19: Sensitivity Analysis of N_2O Emission Factors in the 2020 BAU Scenario



The y-axis represents percent change in net lifecycle GHG emissions for a given scenario due to a change in a specified parameter or process (as indicated by the legend).

Source: Lawrence Berkeley National Laboratory

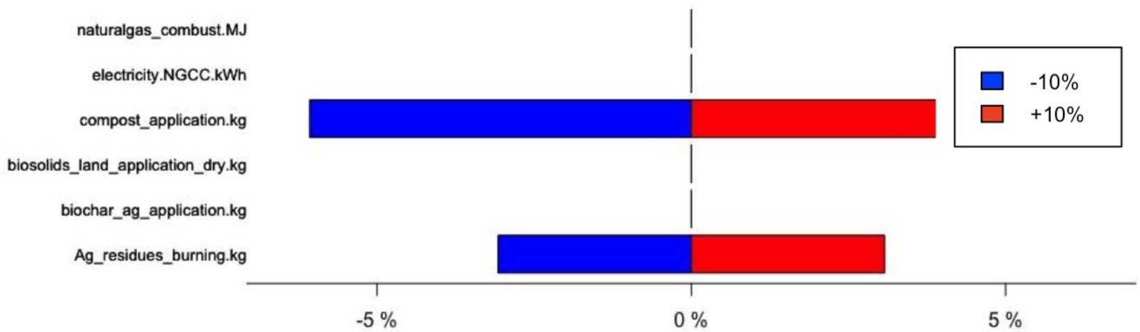
Figure 20: Sensitivity Analysis of CH_4 Emission Factors in the 2020 BAU Scenario



The y-axis represents percent change in net lifecycle GHG emissions for a given scenario due to a change in a specified parameter or process (as indicated by the legend).

Source: Lawrence Berkeley National Laboratory

Figure 21: Sensitivity Analysis of CO_2 Emission Factors in the BAU Scenario



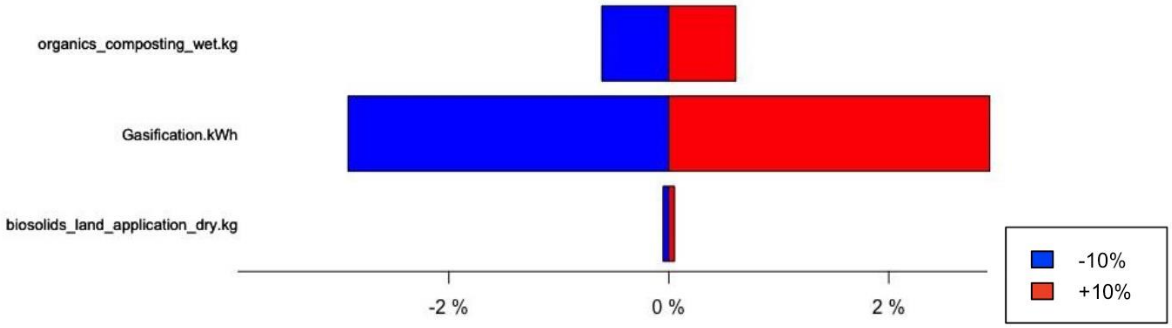
The y-axis represents percent change in net lifecycle GHG emissions for a given scenario due to a change in a specified parameter or process (as indicated by the legend).

Source: Lawrence Berkeley National Laboratory

Sensitivity of Electricity High Price Scenario

A number of parameters led to substantial changes in lifecycle GHG emissions of the Electricity High Price scenario, suggesting the clear value in additional research that can further bound and verify assumptions and emission factors used in this study. Results in Figure 22, Figure 23, and Figure 24 reflect a 10 percent change in parameter values; no significant nonlinearities are identified. CH_4 emissions from landfilling of organics, CH_4 emissions from organics composting, direct CO2 emissions from composting application, and direct CO_2 and N_2O emissions from gasification all drive results for this scenario.

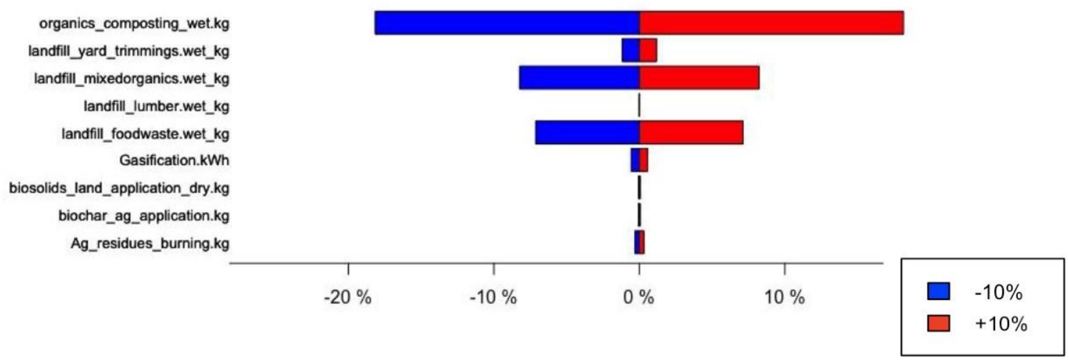
Figure 22: Sensitivity Analysis of N_2O Emission Factors in the Electricity/High Scenario



The y-axis represents percent change in net lifecycle GHG emissions for a given scenario due to a change in a specified parameter or process (as indicated by the legend).

Source: Lawrence Berkeley National Laboratory

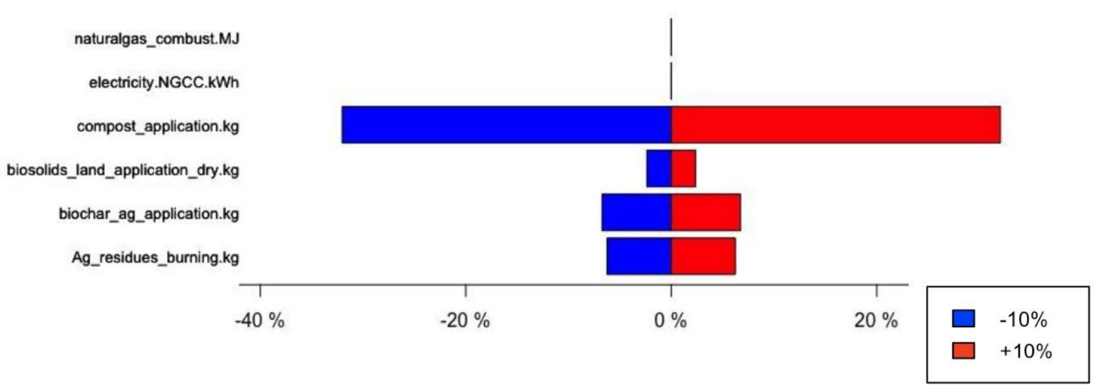
Figure 23: Sensitivity Analysis of CH_4 Emission Factors in the Electricity/High Scenario



The y-axis represents percent change in net lifecycle GHG emissions for a given scenario due to a change in a specified parameter or process (as indicated by the legend).

Source: Lawrence Berkeley National Laboratory

Figure 24: Sensitivity Analysis of CO_2 Emission Factors in the Electricity/High Scenario



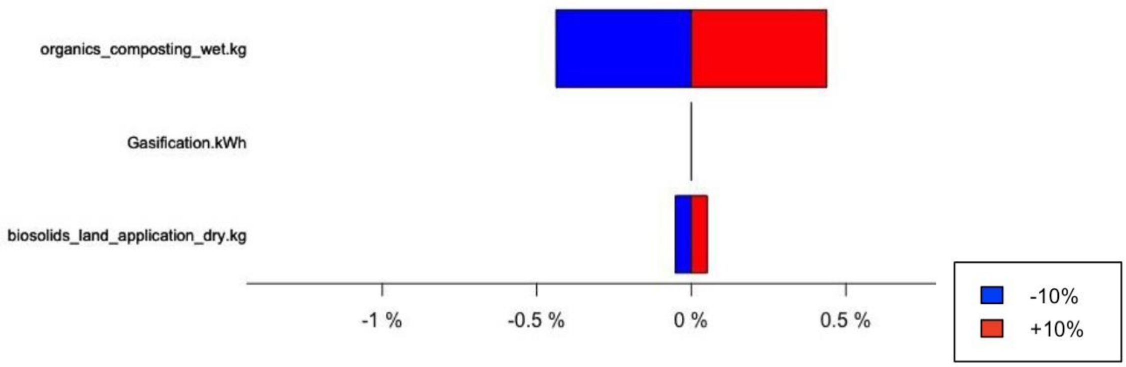
The y-axis represents percent change in net lifecycle GHG emissions for a given scenario due to a change in a specified parameter or process (as indicated by the legend).

Source: Lawrence Berkeley National Laboratory

Sensitivity of RNG Scenario

Similar to the BAU scenario, the RNG scenario showed less sensitivity to emission factor variation than the Electricity High Price scenario. Results in Figure 25, Figure 26, and Figure 27 reflect a 10 percent change in parameter values; no significant nonlinearities are identified. Direct CO_2 emissions from the application of compost on land and from the burning of organics on farms are found, followed by CH_4 emission from composting of organics and the landfilling of organics all drive results for this scenario.

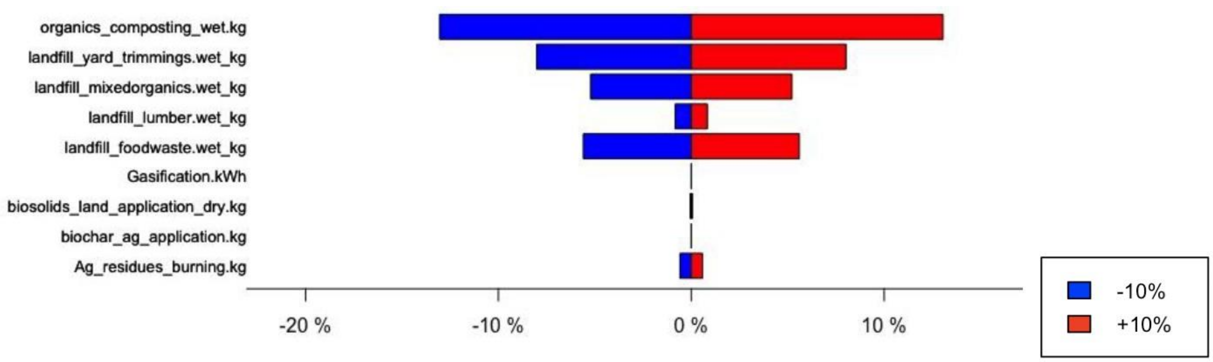
Figure 25: Sensitivity Analysis of N_2O Emission Factors in the RNG/High Scenario



The y-axis represents percent change in net lifecycle GHG emissions for a given scenario due to a change in a specified parameter or process (as indicated by the legend).

Source: Lawrence Berkeley National Laboratory

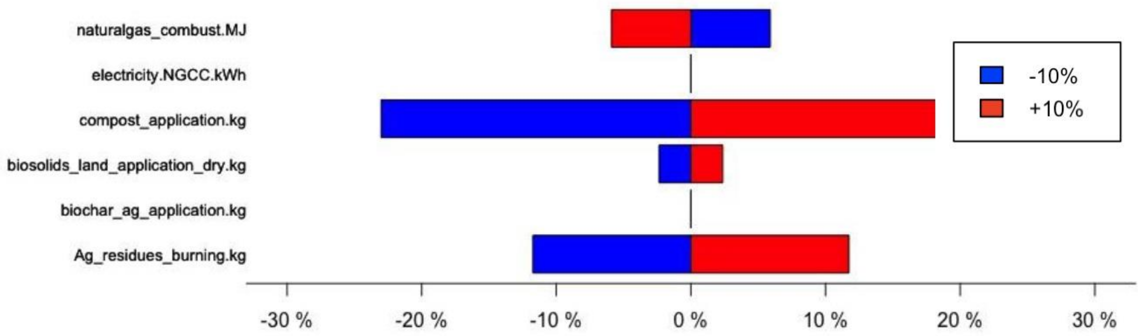
Figure 26: Sensitivity Analysis of CH_4 Emission Factors in the RNG/High Scenario



The y-axis represents percent change in net lifecycle GHG emissions for a given scenario due to a change in a specified parameter or process (as indicated by the legend).

Source: Lawrence Berkeley National Laboratory

Figure 27: Sensitivity Analysis of CO_2 Emission Factors in the RNG/High Scenario



The y-axis represents percent change in net lifecycle GHG emissions for a given scenario due to a change in a specified parameter or process (as indicated by the legend).

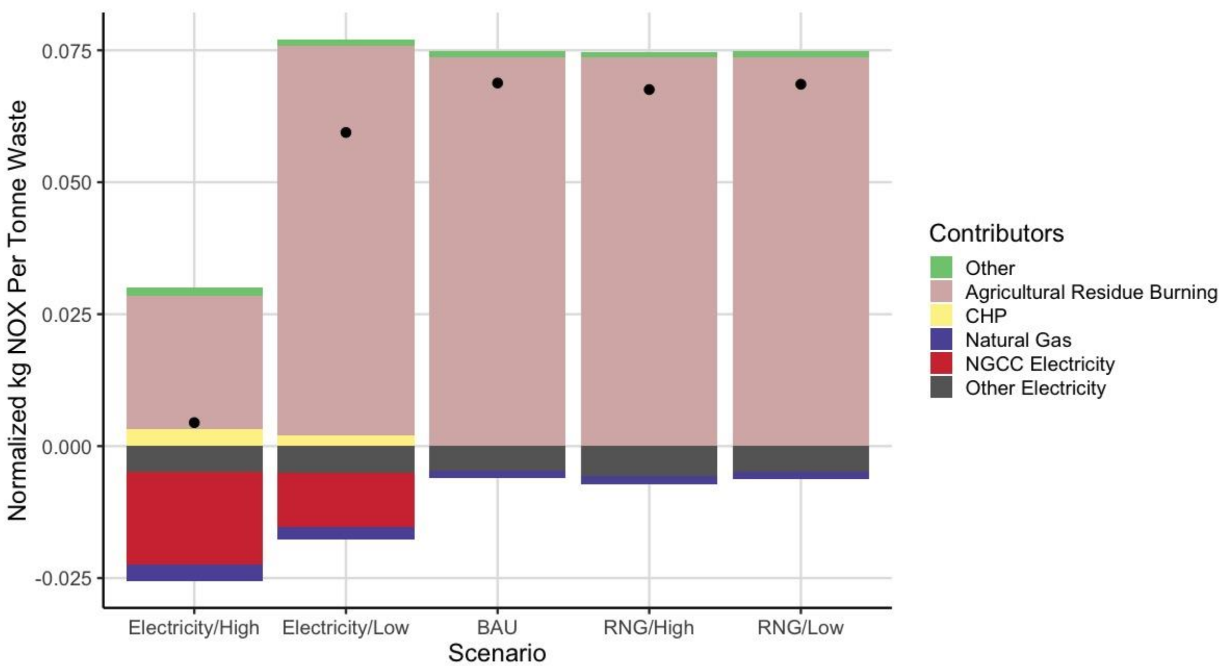
Source: Lawrence Berkeley National Laboratory

5.2.4 Lifecycle Analysis Results for Non-Greenhouse Gas Air Pollutant Emissions

5.2.4.1 Lifecycle NO_x Emissions

Agricultural residue burning is reported as the most significant contributor to lifecycle NO_x from biomass waste to energy technologies, despite the large amounts of waste being diverted to anaerobic digestion and gasification (Figure 28 and Figure 29). Combustion of natural gas in a combined heat and power unit to produce electricity is the second largest contributor.

Figure 28: Lifecycle NO_x Emissions from Various Waste Management Techniques - 2020

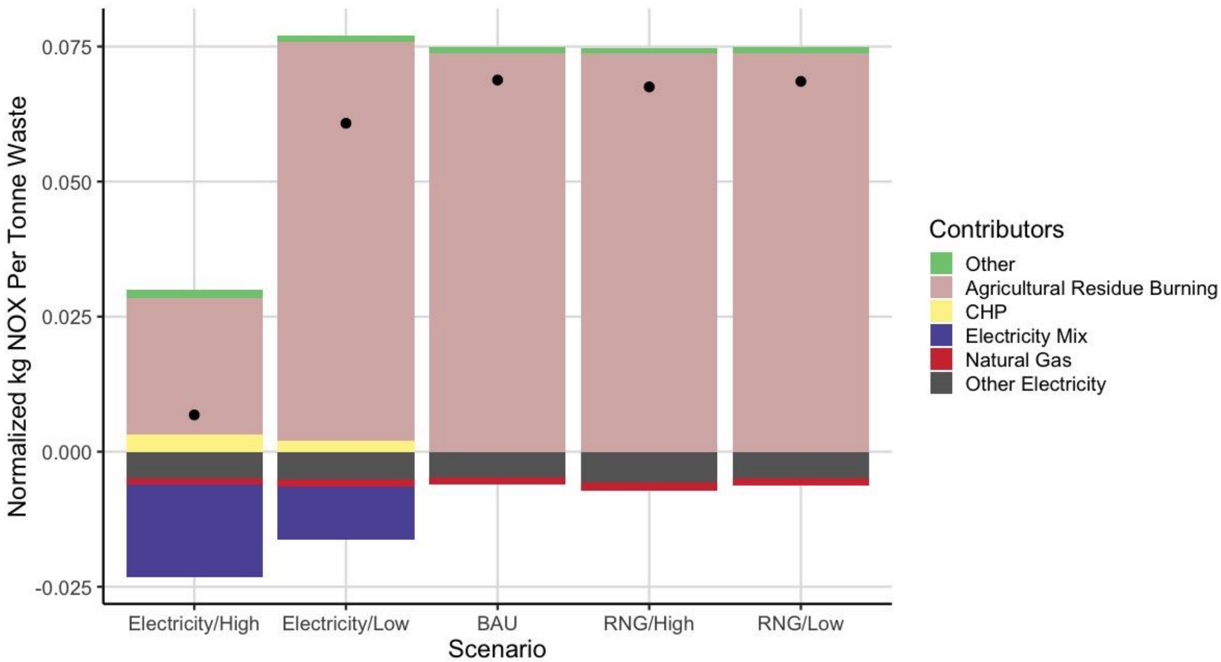


The black dot indicates net emission rate for a given scenario.

Source: Lawrence Berkeley National Laboratory

Natural gas offsets observed are due to urea offsets; the production of which consumes natural gas. The category “Other Electricity” refers to the electricity used in the upstream process of fertilizer manufacturing, an offset which is captured as a result of compost application on working soils.

Figure 29: Lifecycle NO_x Emissions from Various Waste Management Techniques - 2050



The black dot indicates net emission rate for a given scenario.

Source: Lawrence Berkeley National Laboratory

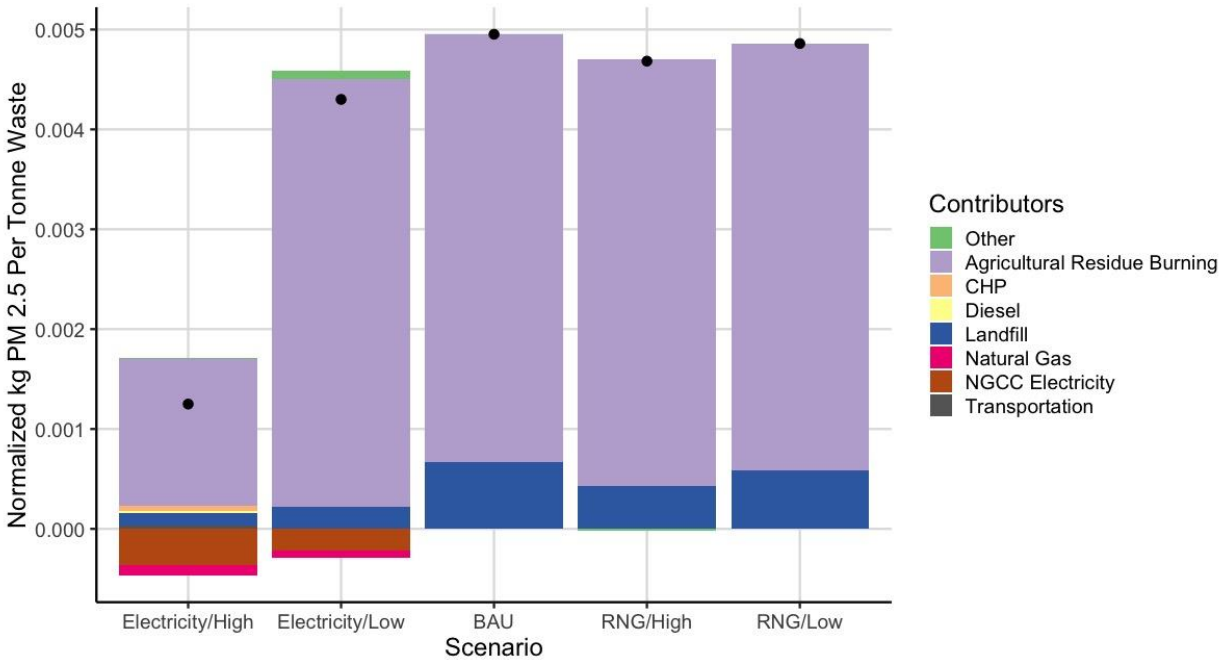
Like CO_2eq, the electricity conversion scenario with a higher energy price results in the lowest lifecycle NO_x emissions of the scenarios under consideration. In the case of NO_x, this is because this scenario increases the amount of agricultural residue diverted from open pile burning. Minimizing/avoiding agricultural residue burning from all the waste to energy options can lower the lifecycle NO_x to an extent, provided that NO_x from open pile burning cannot be avoided completely.

Earlier research reported that fuel combustion and biomass burning were major source of NO_x emission, out of which, fuel combustion accounted for roughly 50 percent of it (Zyrichidou et al. 2015) while 20 percent come from electric power plants (Cox and Blaszczak 1999). In an effort to reduce NO_x emissions, California Air Resource Board has passed regulations for on-road, marine and agricultural vehicles as well as public utilities. However, without the proper use of NO_x capture techniques in industries, power plants and vehicles, the target have not been achieved. EPA recommended several NO_x reduce/capture techniques with an aim to reduce NO_x from combustion activities such as reducing peak temperatures, use of sorbent and absorbent, nitrogen removal prior to combustion, among others (Cox and Blaszczak 1999). EPA further reported that limiting the excess flow of air inside the combustion engine could reduce NO_x generation. Even though NO_x free combustion engines do not exist, the combustion of fuels can be controlled in such a way that the NO_x emissions can be controlled. NO_x from electricity grid mix reduced by half for the waste generated in 2050 as the grid mix assumed 60 percent renewable source for electricity production that avoided combustion of natural gas (Figure 29). The net impacts remained approximately equal even with the 16 percent increase in average total waste stream.

5.2.4.2 Lifecycle $PM_{2.5}$ Emissions

Combustion of fossil and non-fossil fuels are significant contributors of $PM_{2.5}$ emissions (F Laden et al. 2000; Francine Laden et al. 2000). Agricultural residue burning is found as the most significant contributor to lifecycle $PM_{2.5}$ from waste to energy scenarios evaluated despite the large amount of waste diverted to anaerobic digestion and gasification (Figure 30 and Figure 31). Landfill gas flare and natural-gas derived electricity offsets are the next most significant contributors to $PM_{2.5}$. Only 15-30 percent of produced landfill gas is estimated to be flared by landfill facilities, and PM emissions from landfill gas flare is relatively small. Lifecycle $PM_{2.5}$ from the transportation of waste to the treatment facility and digestate from the facility are also relatively small.

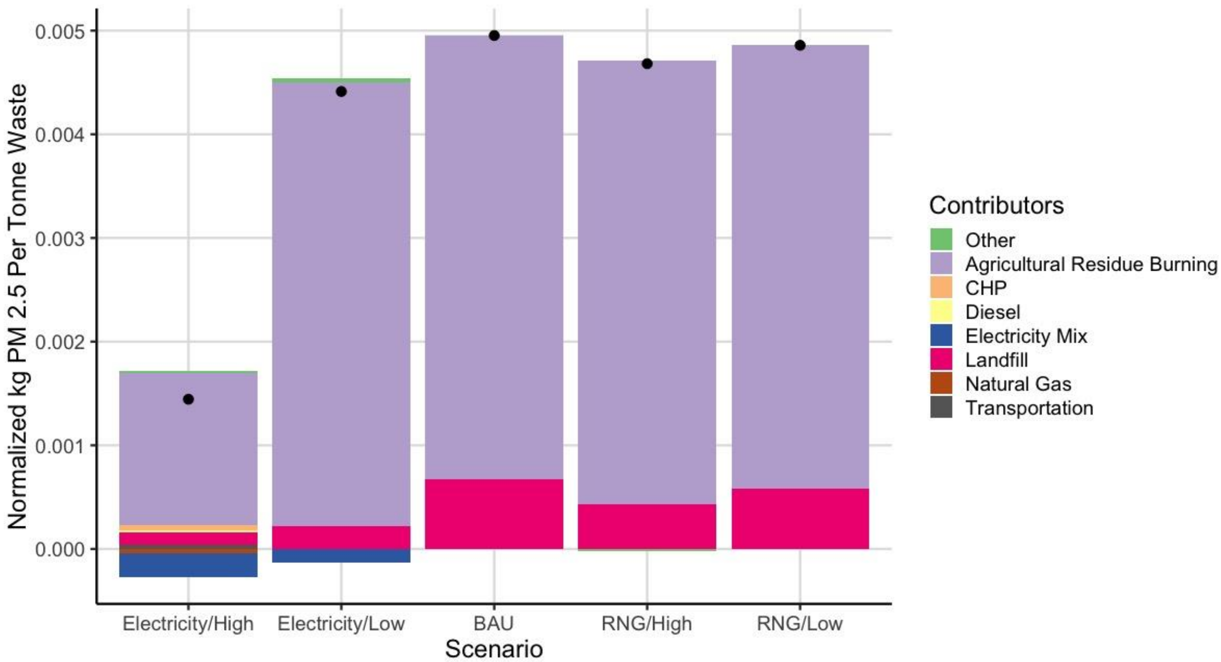
Figure 30: Lifecycle $PM_{2.5}$ Emissions from Various Waste Management Techniques - 2020



The black dot indicates net emission rate for a given scenario.

Source: Lawrence Berkeley National Laboratory

Figure 31: Lifecycle $PM_{2.5}$ Emissions from Various Waste Management Techniques - 2050



The black dot indicates net emission rate for a given scenario.

Source: Lawrence Berkeley National Laboratory

Like CO_2eq and NO_x emissions, the electricity conversion scenario with a higher energy price results in the lowest lifecycle $PM_{2.5}$ emissions among the scenarios under consideration. This can be attributed to the large diversion of low-moisture wastes away from open pile burning. Scenarios with partial landfill of organic waste had net higher PM emissions due to emissions from landfill gas flare.

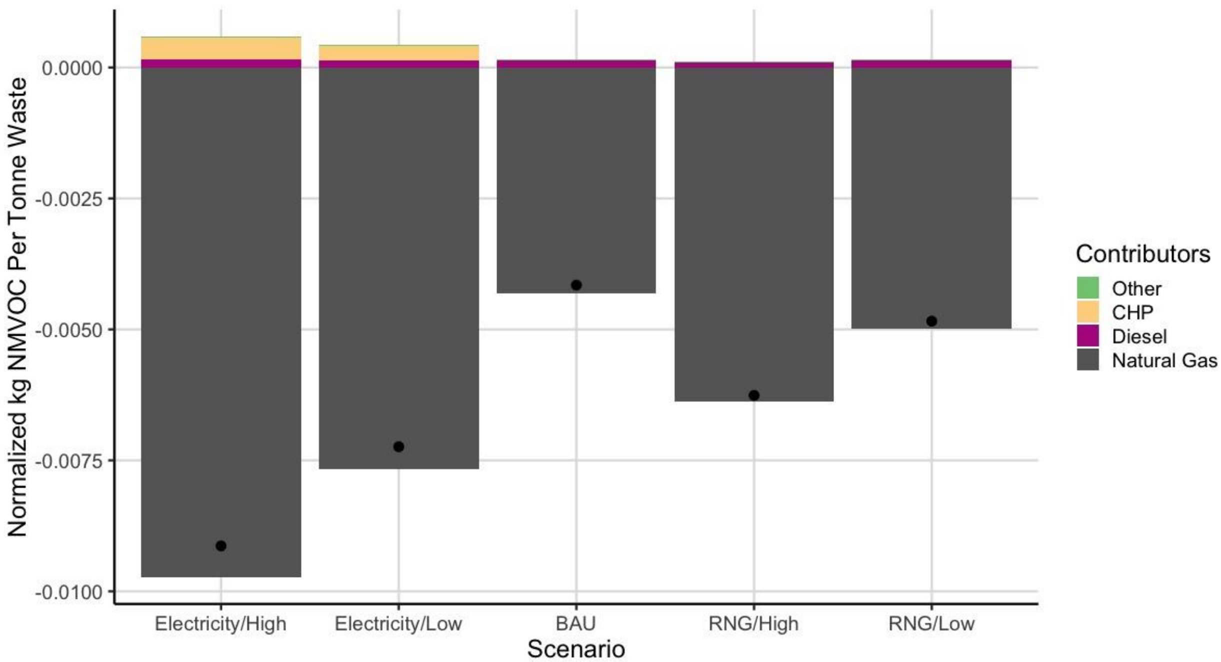
Use of emission reduction technologies such as ceramic filters (for high temperatures > 800° C), absolute fabric/ paper filters (for toxic emissions), electrostatic precipitators (for <400° C), wet scrubbers and mechanical collectors in the flare and CHP exhaust can help minimize PM emissions from stationary sources (Van Harmelen et al. 2002). PM from non-stationary transportation sectors can be minimized by the use of reheated filter in the vehicle exhaust (Wardoyo et al. 2017). $PM_{2.5}$ from electricity grid mix reduced by half for the waste generated in 2050 as the grid mix assumed 60 percent renewable source for electricity production that avoided combustion of natural gas (Figure 31). The net impacts remain approximately equal even with the 16 percent increase in average total waste stream.

5.2.4.3 Lifecycle VOC Emissions

Production and distribution of natural gas and diesel are identified as the two most significant contributors to lifecycle NMVOC among the waste to energy scenarios evaluated (Figure 32 and Figure 33). NMVOC emissions from gasoline production have been reported as significant source of ozone precursors (Gilman et al. 2013), arising from fugitive emissions from the storage and distribution of crude oil. Precautions such as the closed containment of natural gas during loading, unloading and storage could help reduce NMVOC from natural gas and diesel. Combustion in gas engines for power generation (CHP) emits NMVOC due to incomplete combustion of natural gas in the gas engine as well as from the solvents used in the natural gas production (Klimont et al. 2002; Amous 2018) and depend on the mode of operation of gas engine. While, an open dump site releases significantly higher NMVOC (Majumdar et al. 2014), the landfills in California are reported to emit significantly low fugitive NMVOC emissions.

Electricity conversion scenario with higher energy price is the most attractive waste to energy technology in terms of lowering NMVOC emissions. Substantial NMVOC offsets can be attributed to avoided natural gas production used for NGCC electricity and for fertilizer manufacturing. A BAU scenario with partial composting is also found to have an offset of NMVOC from natural gas production as compost offsets urea fertilizer consumption.

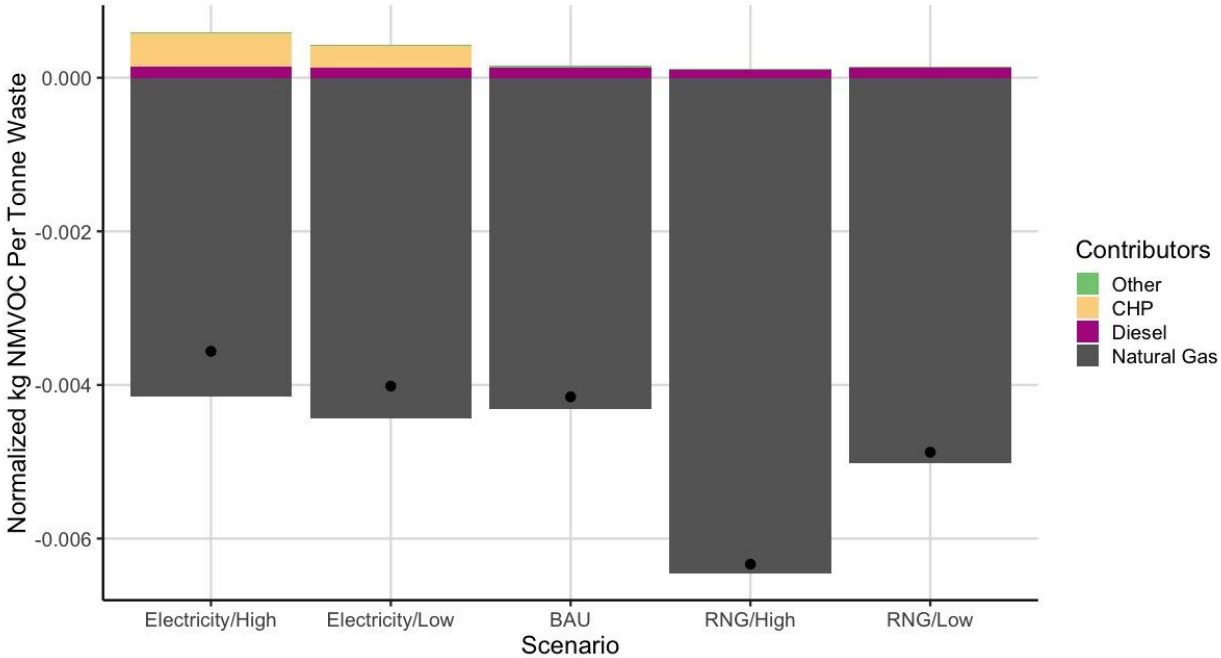
Figure 32: Lifecycle NMVOC Emissions from Various Waste Management Techniques - 2020



The black dot indicates net emission rate for a given scenario.

Source: Lawrence Berkeley National Laboratory

Figure 33: Lifecycle NMVOC Emissions from Various Waste Management Techniques - 2050



The black dot indicates net emission rate for a given scenario.

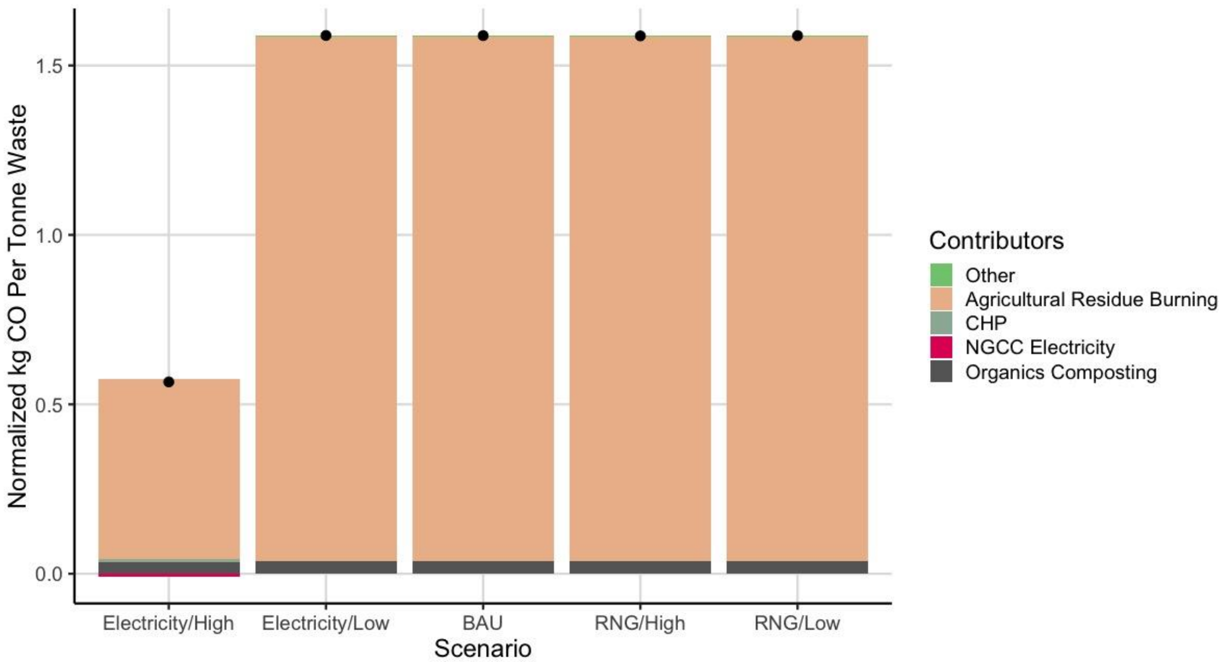
Source: Lawrence Berkeley National Laboratory

5.2.4.4 Lifecycle CO Emissions

Agricultural residue burning is the largest contributor to lifecycle CO emissions (Figure 34 and Figure 35). Organics composting also emits CO and is thought to be due to thermal oxidation (Hellebrand and Schade 2008; Phillip et al. 2011; Haarstad et al. 2006), however biological production of CO is poorly understood (Rich and King 1999). Landfill gas is a small source of CO as organics at landfills decomposed slower than compost at lower temperature on average. A positive correlation has been noticed between CO and H_2S (Haarstad et al. 2006), indicating H_2S may need to be controlled for and monitored at composting facilities. Finally, incomplete combustion of biogas and natural gas contribute carbon monoxide.

The electricity conversion scenario with higher energy price results in the lowest lifecycle CO emissions among the scenarios under consideration because least amount of agricultural residue is diverted to open pile burning.

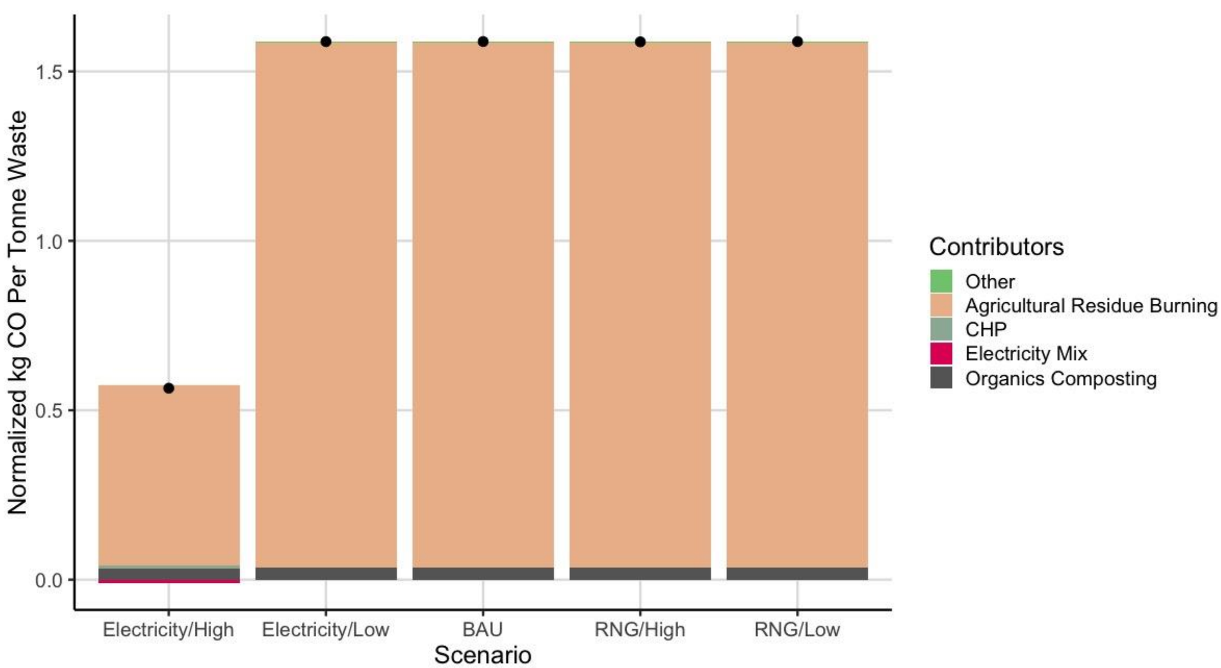
Figure 34: Lifecycle CO Emissions from Various Waste Management Techniques - 2020



The black dot indicates net emission rate for a given scenario.

Source: Lawrence Berkeley National Laboratory

Figure 35: Lifecycle CO Emissions from Various Waste Management Techniques - 2050



The black dot indicates net emission rate for a given scenario.

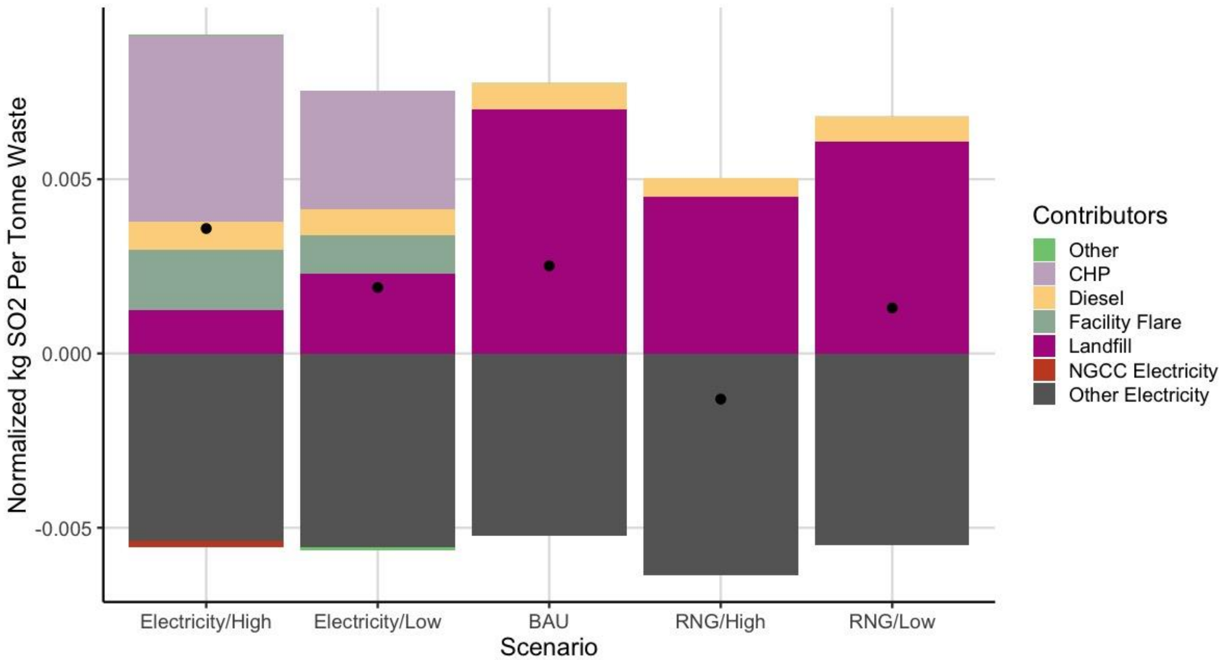
Source: Lawrence Berkeley National Laboratory

5.2.4.4 Lifecycle SO_2 Emissions

Lifecycle SO_2 emissions are mainly attributed to CHP, flaring and the Other Electricity lifecycle stage used in fertilizer production (Figure 36 and Figure 37). Landfill gas flare is a significant contributor to lifecycle SO_2 which is to be expected as landfill gas can have high sulfur concentrations. Combustion of biogas in gas engine for power generation (CHP) and biogas flare emit SO_2 due to the combustion of sulphur content (H_2S) in biogas. Wet flue gas and dry injection desulphurization before biogas combustion can help minimize SO_2 emissions from CHP and flare.

Pipeline scenario with higher energy price is the most attractive waste to energy strategy because it avoids emissions from CHP and flare despite an increase in emissions from landfill. Sulfur is removed from biogas in this scenario, resulting in lower SO_2 emissions during end use.

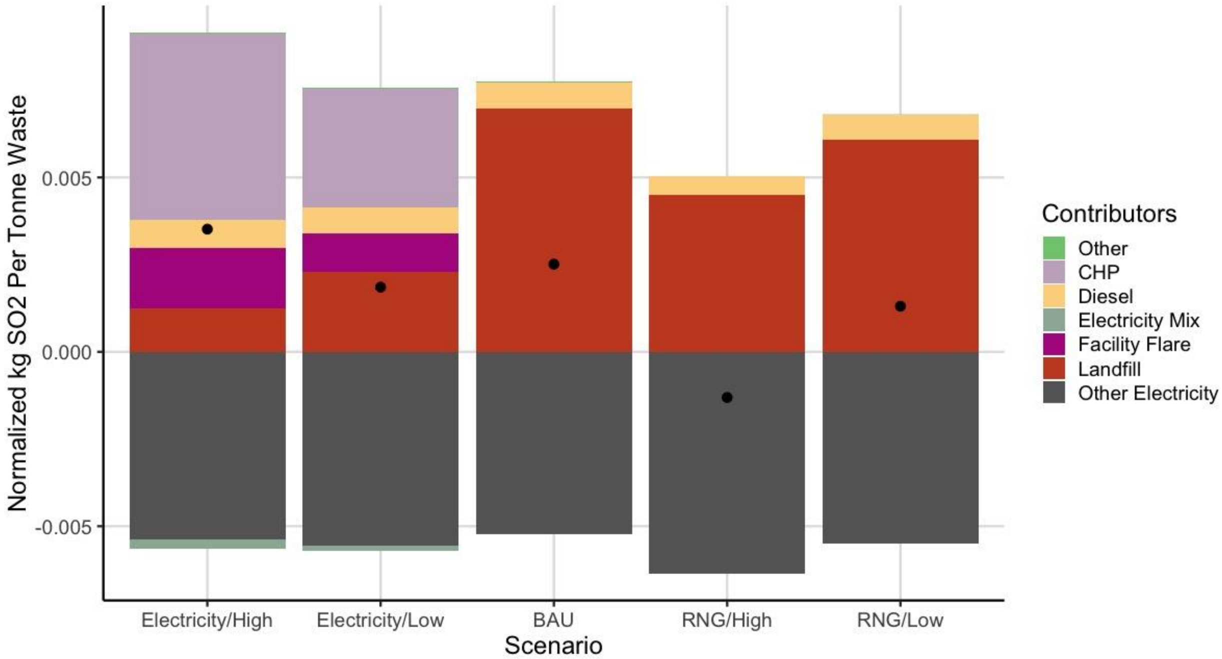
Figure 36: Lifecycle SO_2 Emissions from Various Waste Management Techniques - 2020



The black dot indicates net emission rate for a given scenario.

Source: Lawrence Berkeley National Laboratory

Figure 37: Lifecycle SO_2 Emissions from Various Waste Management Techniques - 2050



The black dot indicates net emission rate for a given scenario.

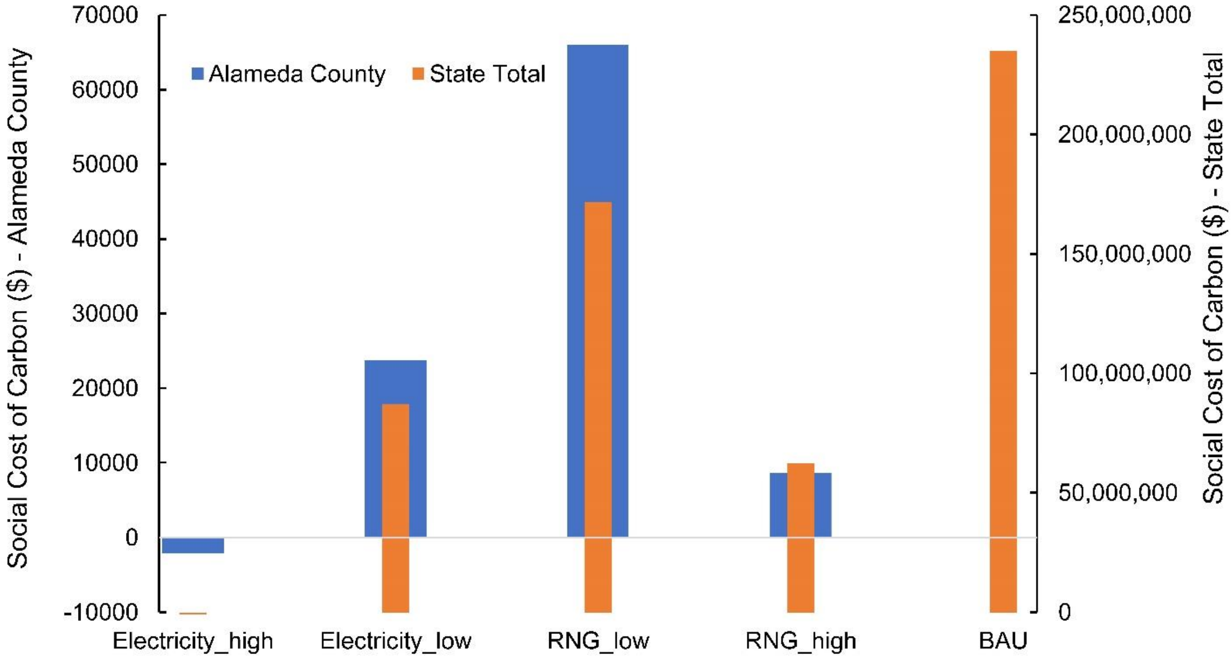
Source: Lawrence Berkeley National Laboratory

5.2.5 Results – Social Cost of Carbon

A wide range of damages are attributed to climate change as a result of greenhouse gas emissions. An end-point metric, referred to as the social cost of carbon, is the monetized value of these damages and can be used to present a cumulative measure of the impacts stemming from greenhouse gas emissions. A social cost of carbon of \$36/tCO_2eq is used as a conservative estimate. For comparison, values for the social cost of carbon have been compiled by the Interagency Working Group on Social Cost of Carbon (White House 2013), for use in regulatory analysis, and provide an intermediate value of \$37/tCO_2eq (\$2007). The social cost is estimated based on the assumptions for likely economic damage that might happen under future climate change. A 3 percent inflation rate is used to estimate social cost of carbon for the year 2020 and 2050. The BAU case is a hypothetical scenario that does not maps out specific landfill, compost or burning facilities (no real location), instead, an average travel distance to the landfill or compost facility is assumed.

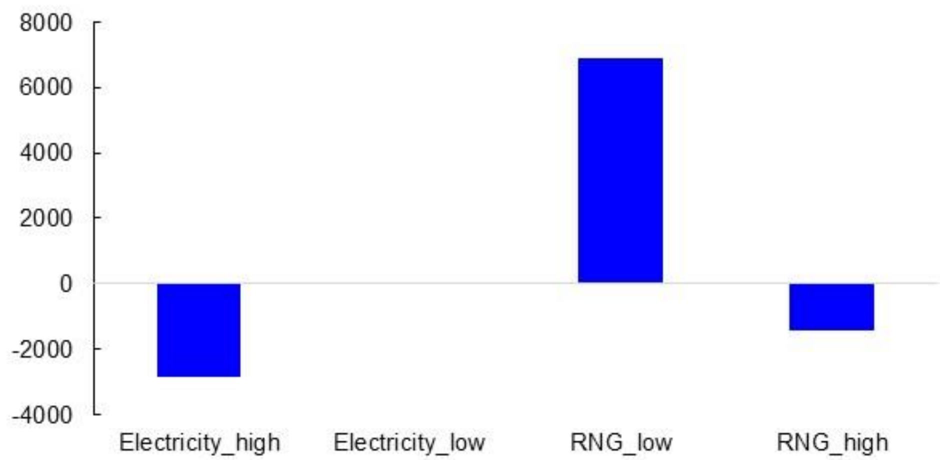
The team estimates CO_2eq emissions in kg per metric tonne of waste for scenarios in all counties, and present results for scenarios implementing electricity generation and renewable natural gas production in Figure 38 and Figure 39. Among various scenarios under consideration, electricity conversion scenario with higher energy price has net negative social cost of carbon for Alameda and Yolo counties (Figure 38 and Figure 39), while biomethane injection via pipeline at higher cost has the higher social cost. These plots are not direct comparisons of electricity generation versus RNG production from the same waste, but the scenario results which are associated with flows of diverse waste organics to processing facilities and conventional disposal, as determined by set price points. The total waste entering the hypothetical facility with partial burning, landfill and composting is equal to 5,38,47,212 wet tonnes. Net CO_2eq emissions from landfilling, composting and burning the is 121 kg CO_2eq/tonne of waste. Among various scenarios under consideration, electricity conversion scenario with higher energy price is the most attractive waste to energy strategy with net negative social cost of carbon for Alameda County and for the state, while biomethane injection via pipeline at higher cost is the worst with higher social cost. In comparison, the hypothetical BAU scenario has the highest social cost of carbon, resulting in $234,926,770 of damages annually from GHG emissions.

Figure 38: Social Cost of Carbon – Alameda County and State Gross from Various Biomass Energy Technologies - 2020



Source: Lawrence Berkeley National Laboratory

Figure 39: Social Cost of Carbon ($) from Various Waste Management Techniques for Yolo County in 2020



Source: Lawrence Berkeley National Laboratory

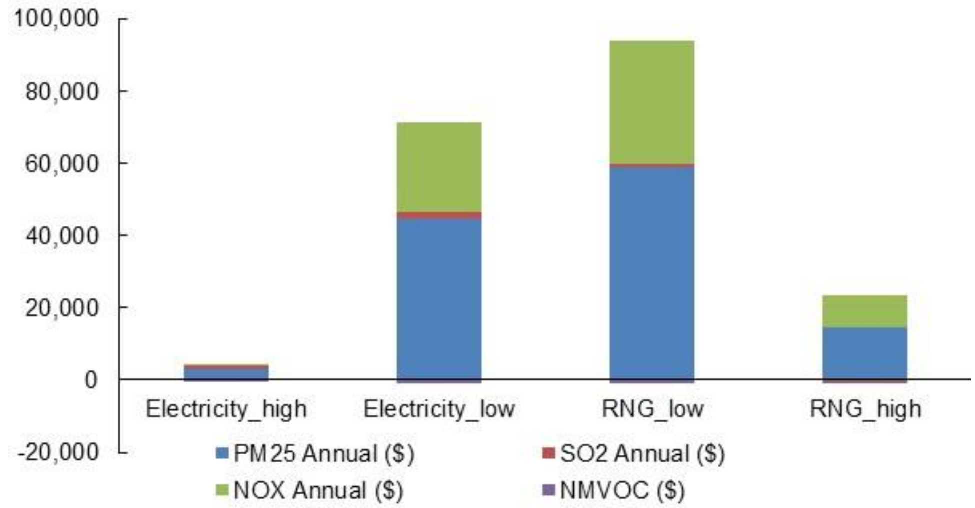
5.2.6 Results – Public Health Damage Cost from Air Pollutants

The Washington Post in 2011 reported that air pollution from energy production caused $131 billion damages to the public health in that year. Air pollution is the main contributor to many serious diseases to the public. Estimating public health cost from air pollutants is crucial in policy research. This section presents public health damage cost of biomass energy projects in the State of California.

In this study, the Estimating Air Pollution Social Impact Using Regression (EASIUR) model is used to estimate public health cost of the direct air pollutants from proposed facilities in the scenarios, as further discussed in Section 5.3.1. Assuming a ground level stack height, the unit public health cost from NO_X, $PM_{2.5}$ and SO_2 for the proposed facility locations are estimated. An inflation rate of 3 percent is assumed to estimate health damage cost for the year 2050 and present results for Alameda county to given an example of results in an urban region. Upstream processes such as natural gas, urea fertilizer, and diesel are not modeled as site specific emissions in the lifecycle analysis, and therefore only evaluate direct emissions from facilities and not net or gross lifecycle monetized damages from criteria air pollutants.

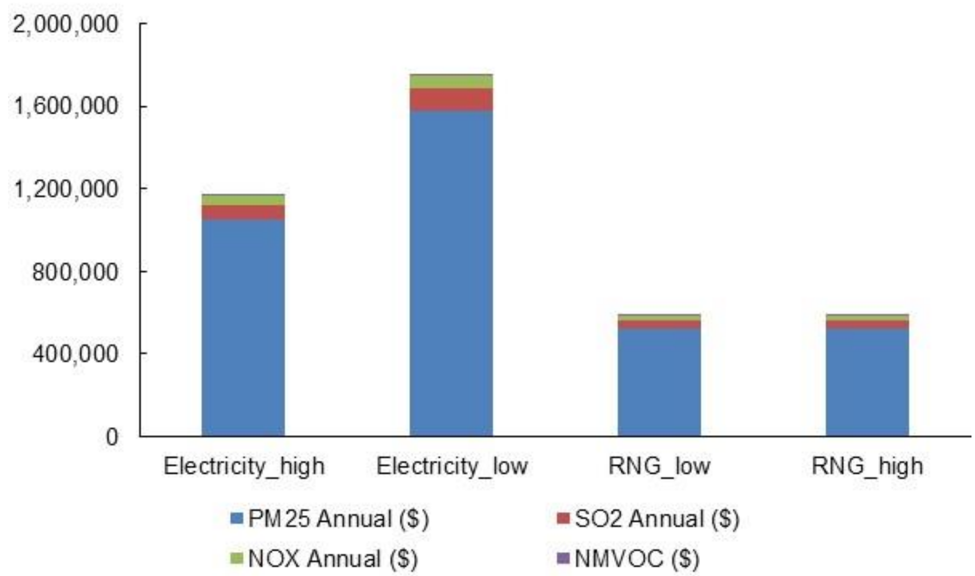
As expected, the electricity conversion scenario with higher price results in the lowest damages to public health in the year 2020 (Figure 40). The team estimates biomethane injection via pipeline may result in approximately $93,000 damages per year, most of which is caused by $PM_{2.5}$ and NO_x emissions (Figure 40). $PM_{2.5}$ and NO_x from agricultural residue burning from RNG scenario are the main cause of public health damage in Alameda county waste-to-energy projects (Figure 40 and Figure 41). On average, $PM_{2.5}$ leads to more costly damage than SO_2 and NO_x. SO_2 is found to have higher damages on a per tonne basis than NO_X, explaining how the two can have similar contributions despite SO_2 emissions being approximately 10 times less than NO_x. Assuming a 3 percent inflation rate for 2050, the public health damage cost due to air pollutants from the electricity high scenario increased by 300 percent, electricity low by 25 percent, RNG low by 6 percent and RNG high increased by 25 percent. The $PM_{2.5}$ emerged as the major contributor to most health damage in 2050 (Figure 40 and Figure 41). This was because of its higher unit damage cost with a continuous inflation for 30 years.

Figure 40: Public Health Damage Cost ($) from Various Waste Management Techniques for Alameda County in 2020



Source: Lawrence Berkeley National Laboratory

Figure 41: Public Health Damage Cost ($) from Various Waste Management Techniques for Alameda County in 2050



Source: Lawrence Berkeley National Laboratory

5.3 Cost Assessment

Two models have been built for analyzing costs in this work: a conversion facility cost model and a district energy cost model. The conversion facility cost model estimates the quantity of biogas, biomethane, or syngas that can be produced throughout California at various price levels. Additionally, it estimates statewide electricity generation economic potential if all conversion facilities produced electricity in on-site generators. The model utilizes the biomass inventory data shared in Chapter 2 and information regarding waste tipping fees, expected biogas or syngas yield, and facility capital and operational costs. The district energy cost model then assesses the feasibility of purchasing biogas, biomethane, and syngas at the various price levels determined in the facility cost model based on expected capital and operational costs and energy sales revenues. The inherent assumption is that for a district energy facility to utilize biogas or syngas, it would need to be co-located with the digestion or gasification facility, while biomethane can be purchased through the natural gas distribution system.

5.3.1 Conversion Facility Cost Model

The conversion facility cost model conducts a statewide analysis utilizing a site-level cost and optimization model. For a given site, the model assesses the available feedstocks within a defined maximum distance and calculates the expected costs and revenues of building different types of facilities at different scales at the site. The model then chooses the most profitable facility at that given site, and compares it to all other sites in the model. The most profitable facility is chosen and "built", and its accepted feedstocks are removed from the analysis. The process is then repeated with the remaining feedstocks to determine the next facility built. Once no more profitable facilities are possible, the model aggregates the total amount of biogas or biomethane produced, the total waste processed, and the types and sizes of facilities built. This process is conducted for different energy types (biogas, biomethane, or syngas) at various price levels. The result is a supply curve of energy products in the state, as well as other data of interest such as waste diversion and ideal facility types and locations. The team modeled 2020 and 2050.

It should be emphasized that this model does not maximize the energy production or waste conversion in a given scenario, and therefore does not represent the total economic potential of these technologies. Rather, it aims to mimic the way California's waste conversion infrastructure is likely to be developed, with lower-cost, more profitable facilities being built first and procuring the most valuable wastes, and additional facilities being built around what is available. Outside intervention would be necessary to distribute the most profitable waste streams across multiple facilities in order to maximize the total quantity of waste that can be economically converted to energy.

The model considers five anaerobic digestion facility types: dry AD, stand-alone wet AD, co-digestion at wastewater treatment facilities (WWTF), on-farm dairy digesters, and gasification. Potential sites for WWTF AD are existing WWTF with excess digester capacity, as determined in the biomass supply inventory portion in Chapter 2. For stand-alone wet and dry AD and gasification, potential sites are existing or planned solid waste handling sites in California such as landfills, transfer stations, or compost facilities (CalRecycle 2018b). Dairy farm sites are as identified by point sources of dairy manure in the biomass inventory data.

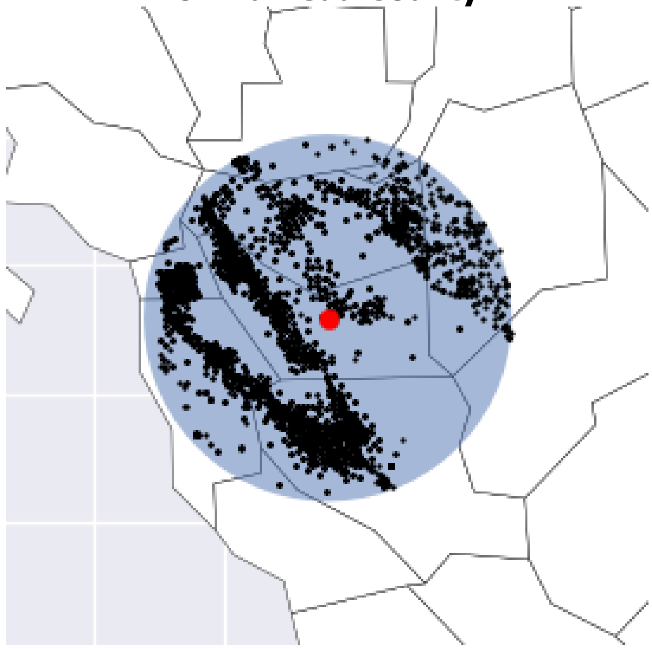
Data regarding the type, location, and annual quantity of organic waste in California in 2020 is obtained from the biomass inventory portion of this study. There are over 70,000 feedstock supply points in the model covering 125 different types of waste. The 125 waste types are mapped to various characteristics: how it can be processed, how much methane and/or syngas it generates, the tipping fee (or cost) to procure, and the moisture content. Processing category is important to realistically assigning waste streams to the five facility types. For example, wet AD is limited to accepting liquids and high moisture solids, while dry AD cannot accept liquids but can accept low or high moisture solids. Methane yield is feedstock- and facility type-specific, and can vary significantly across waste types. Lastly, the tipping fee is based off of the typical disposal method of the waste. This can range from $45, the state median landfill tip fee, all the way down to -$45, for certain agricultural residues that are typically left on-field and would be costly to collect.

A total of seven cost categories are included in the model. These are split into two categories: waste revenues, which include waste tipping fee, waste trucking cost (negative revenue), energy sales revenue, and digestate or biochar handling cost (negative revenue), and three facility costs, facility capital (conversion, codigestion handling, and electricity generation), fixed facility operations and maintenance, and facility labor.

5.3.1.1 Waste Revenue Calculations

For each site and facility type, the model first finds all of the feedstocks that lie within a defined maximum distance from the site and that are accepted at the given type of facility. A maximum transportation distance of 50 miles is assumed, as the average distance a ton of waste travels to before being disposed in California is 33 miles (CalRecycle 2018a) and organic wastes are particularly unsuitable for long travel due to their degradability, moisture, and odors. The 50-mile transportation limit is converted to a Euclidian distance using a detour index of 1.4, found to be generally representative for the United States (Boscoe et al. 2012), which is then used to find all potential feedstocks for the site. The distance between each feedstock and the site is calculated, and then converted into a driving distance using the detour index. An example for a dry AD facility located at the centroid of Alameda County is shown in Figure 42. The four costs under "waste revenues" are calculated for each feedstock point within the buffer zone. Trucking cost ($/tonne) is simply the driving distance between the feedstock and the site multiplied by an assumed trucking cost of 0.20 $/tonne-mi (Sanscartier et al. 2012). Tipping fee is an input assumption in dollars per tonne. Tipping fee assumptions come from state-specific municipal solid waste and green waste tipping fee data (CalRecycle 2015b), national estimates of costs of procuring agricultural wastes (Langholtz et al. 2016), and known costs of liquid waste disposal at a local WWTF (EBMUD 2019).

Figure 42: All Waste Feedstock Points Within a Defined Buffer Zone of the Centroid of Alameda County



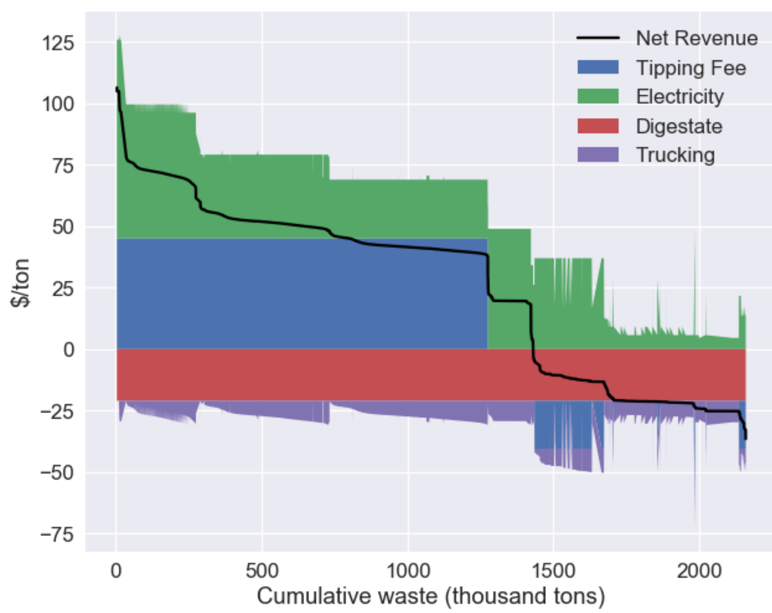
Source: Lawrence Berkeley National Laboratory

Energy revenue is calculated based on the unit price defined for the given scenario, along with the expected gas yield based on the feedstock type, facility type, and scenario. For electricity generation scenarios, 40 percent electrical efficiency of biogas engines is assumed and 25 percent electrical efficiency of syngas engines (Caputo et al. 2005). For digestion facilities selling biogas or electricity, 20 percent of the biogas is assumed flared due to low energy content or limited storage (Hake et al. 2017, ZWEDC 2019), and that if biogas is being sold directly (i.e. not combusted in CHP engines on-site) 5% of the biogas must be diverted to boilers for digester heating (Banks et al. 2018). Digestion facilities upgrading the biogas to biomethane are assumed to experience 3 percent methane losses during the upgrading process, typical for pressure-swing absorption or water scrubbing systems (Angelidaki et al. 2018), and it is assumed they do not have to self-consume any gas for heating as the upgrading process will produce non-methane tail gases that can be combusted in on-site boilers (Goldstein 2018).

Lastly, the digestate handling cost captures what the facility must pay to dispose of the solids remaining after digestion is complete. For wet AD facilities, 34 percent of the initial waste mass is assumed remaining in the solids portion of the digestate, and that liquid digestate is sent to a wastewater treatment plant (or recirculated to the head of the plant if the facility is a WWTF) (Sanscartier et al. 2012). For dry AD, it is assumed 70 percent of the mass remains in the digestate based on known operational facility data (ZWEDC 2019), and for gasification facilities, it is assume 13-34 percent of the solids remain as biochar, depending on the waste type. All solids are assumedd to be disposed of, whether that be at landfill, composting, or land application facilities, for a cost of $30/tonne (Sanscartier et al. 2012, CalRecycle 2015b).

The four waste revenues are summed to obtain a "revenue per tonne" metric. The facilities are assumed to always choose to accept a feedstock with a higher revenue per tonne rather than one with a lower revenue per tonne, and they will not accept any wastes that have a negative total value. Therefore, the set of feasible feedstocks for the site is sorted in terms of decreasing revenue per tonne, and that is the preferred procurement order for the site. An example of the waste "supply curve" at this step is shown below. For a 100,000-tonne facility, the first 100,000 tonnes of highest-revenue waste would be procured, and nothing else. For dry AD digesters, this procurement order is further adjusted to assure that, at any facility size, the fraction of low-moisture wastes is less than or equal to 50 percent of the total wastes. Operational dry AD facilities use at most a 1:1 dry-to-wet waste ratio, as higher dry waste content lowers the biogas yield from the digestion process (ZWEDC 2019, Goldstein 2018, MRWMD 2018). The procurement order for dairy digesters is also slightly altered, in that the first wastes accepted must be 100% of the on-site manure wastes, no matter the value. Finally, the feedstocks are cut at defined tonnage and energy generation limits. WWTF dry tonnage is capped at 1 percent of the estimated maximum available solids loading of the digesters as a base scenario (Breunig et al. 2017), while stand-alone wet and dry AD and gasification facilities are capped at 400,000 wet tonnes per year, as the largest currently planned or operating digestion facility in California has a planned final capacity of about 290,000 tonnes per year (California Climate Investments, 2018). For electricity generation scenarios, a maximum generation capacity of 20 MW is set, as this is the limit for a facility to be defined as "distributed generation", which is the scope of this study. Additionally, the capacity of dairy digesters is limited by assuming they will only be willing to take in co-digestion waste streams up to a tonnage equal to 10 percent of their manure waste tonnage.

Figure 43: Waste Feedstock Supply for a Waste Facility Generating Electricity Located at the Centroid of Alameda County



Source: Lawrence Berkeley National Laboratory

5.3.1.2 Facility Cost Calculations

Once the feedstocks are sorted in terms of waste revenue, facility costs can be calculated. Facility costs include any costs that are a function of total facility or equipment capacity and are nonlinear, and therefore cannot be calculated for individual feedstocks outside of the facility context. Facility capital and labor costs take the form "y = a*x^b" to account for economies of scale, captured by the parameter b which is often referred to as the scaling factor. In these cost equations, "y" is the capital costs in dollars and "x" is the total relevant waste mass in wet tonnes.

A summary of the exponential cost curves used in the model is given in Table 46. For facility capital the parameter "a" is set based on literature and the known cost of $43.5 million for a 90,000-ton facility in California (ZWEDC 2019). According to Sanscartier et al.'s (2012) analysis of wet AD facility costs, and known dry AD facility costs in California, there is not enough information to conclude a significant difference in costs between the two facility types. For WWTF and dairy co-digestion, costs for building a co-digestion receiving station and the associated pumping, screening, and handling equipment are included Based on interviews with WWTF who have built these types of equipment in California, the "a" parameter is calibrated to a $12 million facility that is able to receive 122,000 tons per year (LASAN 2018).

Table 46: Conversion Facility Exponential Cost Curve Parameters

Item	Parameter a	Parameter b	X variable units	References
Wet AD digester	14800	0.7	wet tons/year	Sanscartier et al. 2012
Dry AD digester	14800	0.7	wet tons/year	ZWEDC 2019
Dairy digester	1074	0.7	wet tons/year	Summers and Hurley 2013; California Dairy Campaign 2013
Co-digestion handling	3400	0.7	wet tons/year**	LASAN 2018
Gasification	4257	0.75	wet tons/year	EPA 2007; Ahmad et al. 2016
CHP engine	13147	0.75	kW	EPA 2015
Gas upgrading*	44.289	-0.296	ft3 methane/min	Ong et al. 2014
Labor	100	0.8	wet tons/year	ZWEDC 2019; MRWMD 2018

*** Includes O&M costs**
**** For dairies, only the co-digestion tonnage is included**

Source: Lawrence Berkeley National Laboratory

For biomethane scenarios, add a gas upgrading capital cost, and a pipeline interconnection cost of $1 million, based on estimated interconnection costs and a 50 percent rebate from the California Public Utilities Commission (California Dairy Campaign 2013; CPUC 2019). For electricity generation scenarios, the team includes the cost of a spark-ignited gas engine (SIGE) CHP unit, and an interconnection cost of $200,000 for every 5 MW of generation capacity (Bird et al. 2018). Facility capital cost is transformed from a total investment cost to an annual cost using a simple payment function and amortization. A borrowing rate of 5 percent, payment period of 15 years, and facility lifetime of 25 years are assumed.

Labor costs are also exponential in form, and the a and b parameters are set using two known data points in California: 1 full time operator for a 5,000-ton facility, and 10 operators for a 90,000-ton facility (ZWEDC 2019, MRWMD 2018). A fully burdened cost of 90,000 $/FTE for an annual salary is assumed. Finally, the annual operational costs are calculated as 5 percent of the total capital cost, based on collected facility data.

5.3.1.3 Forecast to 2050

The statewide model is also run for a 2050 scenario, which considers changes in costs, and revenues, and technologies that are possible in the next 30 years. The 2050 waste source data forecasted in the biomass inventory portion of this study is used, and no changes are made to the assumptions regarding what types of facilities can process each waste stream, the maximum distance waste can travel, the maximum facility capacity and WWTP excess capacity, or the set of possible facility locations. The only change to non-cost-related assumptions is a 20% increase in biogas yield for all AD technologies; this is due to current research developments in terms of processing and additive techniques that show promising results for energy yield and are already being demonstrated at small scales. The California Energy Commission has highlighted techniques such as improved feedstock preprocessing and cleaning, codigestion, and the use of enzymes and speciality microbes to increase biogas yields.

Facility capital and interconnection costs are forecasted using historical data for Construction Cost Index (CCI) for San Francisco and Los Angeles (California Department of General Services, 2019), and assumptions about the learning rate of building these facilities. The CCI captures costs trends for labor and materials related to general building construction in terms of nominal price relative to a defined baseline year. The 30-year (1988-2018) compound annual growth rate (CAGR) for the California CCI is approximately 2.5 percent, with 10- to 15-year time scales of showing CAGRs of 2-3 percent. For a medium forecast case, a CAGR of 2.5 percent is used, which means that 2050 construction costs, in nominal prices, will be 2.2 times 2020 costs. An experience curve framework, which examines the relationship between cumulative market production and prices, is used to capture the fact that prices for new technologies and systems tend to decline with production due to factors such as improvements in labor skills, efficiency in manufacturing and building processes, and market competition (Smith et al. 2016). The "learning rate" parameter represents the percent price (or in some cases, cost) reduction for every doubling of total production; for the construction industry, a learning rate of 20 percent is commonly assumed. For wastewater treatment co-digestion and dairy co-digestion, and gasification facilities the team assumes no "doubling" in total production occurs, as these are mature technologies that are not likely to see significant cost reductions in terms of learning. This is true for some aspects of stand-alone wet and dry AD facilities as well, but these facilities as a whole are extremely new, particularly in California, so modest cost reductions is assumed in these facilities' capital costs (23 percent by 2050, based on a 10 percent learning rate and 2.5 doublings of total installed capacity). This results in 2050 costs of stand-alone wet and dry AD being equal to 1.7 times 2020 costs.

We assume all on-site electricity generation will occur via fuel cells with electrical efficiency of 50% (Trendewicz and Braun 2013, Combined Heat and Power Partnership 2015c) in 2050, as opposed to the spark-ignited gas engines assumed in 2020. This assumption is made based on the growing prevalence of fuel cells at large WWTF in the United States and the substantial investments in the technology made by agencies such as the Department of Energy (DOE). Costs are estimated using cost forecasts to 2030 with continued nominal price decrease of 2 percent per year. The resulting nominal price of 2484 $/kW for 300 kW systems would require 6 cumulative market doublings at a learning rate of 18% (Wei et al. 2017a), or much fewer if an increase in the learning rate occurs as deployment increases (Wei et al. 2017b). For larger systems, an exponential cost curve is assumed with a scaling factor of 0.8.

Biogas upgrading technology, particularly for low-flow applications such as waste management facilities, is quite young. A 2014 market report estimated the biogas upgrading market to have a 17.4 percent CAGR through 2018 (Hanft, 2014). Based on the market size estimates and future growth assumptions, the biogas upgrading market would likely experience about 6 doublings from 2020-2050. For capital costs it is assumed a learning rate of 10-20 percent, and a conservative range of 4-6 doublings, while O&M costs remain constant in terms of real dollars. All costs increase with inflation, assumed at 2 percent per year. Therefore, total upgrading costs in 2050 would be 0.65-1.1 times the 2020 costs; for the mid case 0.85 is assumed as the multiplier.

Facility labor costs are forecasted using the Employment Cost Index (ECI) for Natural Resources, Maintenance, and Operations sectors from 2008-2018, which indicates a CAGR of 2.1 percent (U.S. BLS 2019a). Trucking costs are forecasted using a combination of labor and fuel cost forecasts, as these are the dominant costs in the trucking sector (Hawes, 2018). EIA forecasts a 0.8 percent annual growth in the cost of motor gasoline in real dollars through 2050 (U.S. EIA 2018), while the transportation sector ECI shows 2.5 percent annual growth in nominal dollars (U.S. BLS 2018). Additionally, the Bureau of Labor Statistics has a Producer Price Index specifically for waste trucking, but with only 5 years of data; these years show a 1 percent CAGR (nominal) (U.S. BLS 2019b). The team assumes an overall annual growth rate of 1.5 percent in nominal dollars for trucking costs out to 2050.

The tipping fees a facility can expect to receive (or pay) for MSW in 2050 are estimated based on landfill and compost facility tipping fee trends. Upcoming state regulations will require jurisdictions to send their organic waste to organics recycling facilities, so digestion and gasification facilities may be able to procure a premium tipping fee depending on how much the compost industry is able to expand to take in high-food, mixed MSW waste streams. From 2000 to 2010, California's average tipping fee increased $17, an average of $1.70 per year, which is comparable to the national trend of $1.62 per ton increase per year (CalRecycle 2015b). If this trend is assumed to continue to 2050, the landfill tipping fee will only have increased 17 percent in terms of real price (assuming 2 percent inflation). Therefore, this is considered a conservative estimate for the increase in landfill tipping fees, and particularly for organics processing tipping fees. Tipping fees for other waste streams are assumed to increase with inflation, such as the amount facilities can receive for liquid waste streams or the amount they would need to pay for agricultural residues that have a collection cost or "gate fee”. The cost to clean-up and slurry high-solid wastes for wet, WWTP, and dairy facilities is assumed to hold a constant nominal cost, so decreases with inflation in terms of real dollars. This is because over time waste sorting and collection practices should improve, and the rapidly developing waste pre-processing industry and technologies should lower costs.

Finally, the low-medium-high nominal energy price scenarios is adjusted to the model so each price level represents approximately the same energy cost relative to that year’s wholesale and retail energy prices. EIA forecasts are used, for a 1.2 percent annual increase in real natural gas costs (for the biomethane price scenario) and 0 percent real cost increase for electricity and syngas. Prices modeled are nominal, so also include inflation.

5.3.1.4 Results

Figure 44 and Table 47 and 48 show total waste processed and electricity generated for all 2020 scenarios that involve generating electricity on-site, while Table 51 shows the fraction of statewide technical potential waste processed in each case. The same results for 2050 are given in Figure 45, Table 49 and 50, and Table 51, respectively. Electricity generation scenario results are useful because, as opposed to biomethane, biogas, and syngas results, this energy pathway is an option for all facility types.

Stand-alone wet and dry AD and dairy digesters are only feasible in 2020 at 12 c/kWh or more due to the need to offset digester capital costs. Wet AD has limited feasibility even at relatively high electricity prices, processing 1.8 million wet tonnes per year (TPY) to generate 65 MW of electricity at 20 cents/kWh. Dry AD’s potential is much higher, primarily due to the wider range of waste streams dry facilities are able to accept. At 20 c/kWh, 7 M TPY are processed generating 250 MW. Only 5 percent of dairy manure (1.4 M TPY) will be processed, even at 20 c/kWh, if dairies are not willing to take co-digestion tonnages above 25 percent of their manure tonnage. Stand-alone wet and dry AD fare much better in 2050, and are significant starting at 14 c/kWh. At the highest modeled electricity price, these facilities are processing almost all of the MSW and food processing resources that they are able to; however, they are still not able to afford to pay for all agricultural residues. While dairy feasibility grows significantly in 2050, it still only manages to process 14 percent of the state’s dairy manure.

Wastewater treatment plant co-digestion is feasible in 2020 at all electricity price points modeled, as waste tipping fees are high enough to offset the co-digestion handling costs even at low energy values. This is especially apparent in the 4 c/kWh scenario, where the ratio of tonnage processed to electricity produced is significantly higher than the other scenarios; here the plants are choosing to accept wastes with higher water content and lower energy production value as they are less concerned with electricity revenue. As electricity prices go up, the marginal returns in terms of waste handling and energy generation decrease. At 20 c/kWh, WWTP process almost 3 M TPY. In 2050, WWTP digestion does not change significantly, due to the fact that the available large treatment facilities are already being utilized in the 2020 scenario. Even at higher gas yield and tipping fee assumptions, the WWTP-only scenario leaves over 60 percent of municipal food wastes unprocessed. Interestingly, FOG waste is not widely accepted at WWTP or other facilities, even though this is typically considered a high-value waste stream due to its high biogas production per solids tonnage. However, the team assumed FOG tipping fees are relatively much lower than other municipal waste streams, based on known WWTP fee structures. A low solids content (3 percent) was assumed, which makes the energy production per wet tonne less competitive with other waste streams.

Lastly, gasification facilities have extremely high potential relative to the other types, primarily due to their relatively low capital costs. In 2020, at 12 c/kWh and below, very high fractions of statewide technically available low-moisture municipal (70-97 percent) and processor (30-74 percent) wastes are gasified with the help of their high tipping fees. At 16-20 c/kWh, essentially all dry MSW and 80 percent of processor LMS are gasified, along with significant amounts of field and orchard and vineyard (OV) residues. This is the only situation in 2020 in which facilities are willing to pay for feedstocks, and is likely only possible due to the significant tipping fees being collected simultaneously from other waste streams. OV residues are more valuable than crop residues, due to the higher syngas generation assumed (approximately 4,000 kWh per bone-dry tonne (BDT) for woody wastes compared to 1850 kWh/BDT for grassier residues), while field residues beat out crop residues due to their much lower moisture content (14 percent vs. 40 percent assumed). Electricity production from gasification increases rapidly by 2050, due to the very syngas-inefficient engines being replaced by fuel cells with high electrical efficiency. This makes gasification even more profitable than it already was in the 2020 scenario, however total tonnage handled only goes up about 30 percent. This is partially because of the assumed maximum facility size of 400,000 wet tonnes per year and the fact that the model does not allow building multiple facilities at a given site; at electricity prices of 14 c/kWh and above the possible sites start getting closer to saturation.

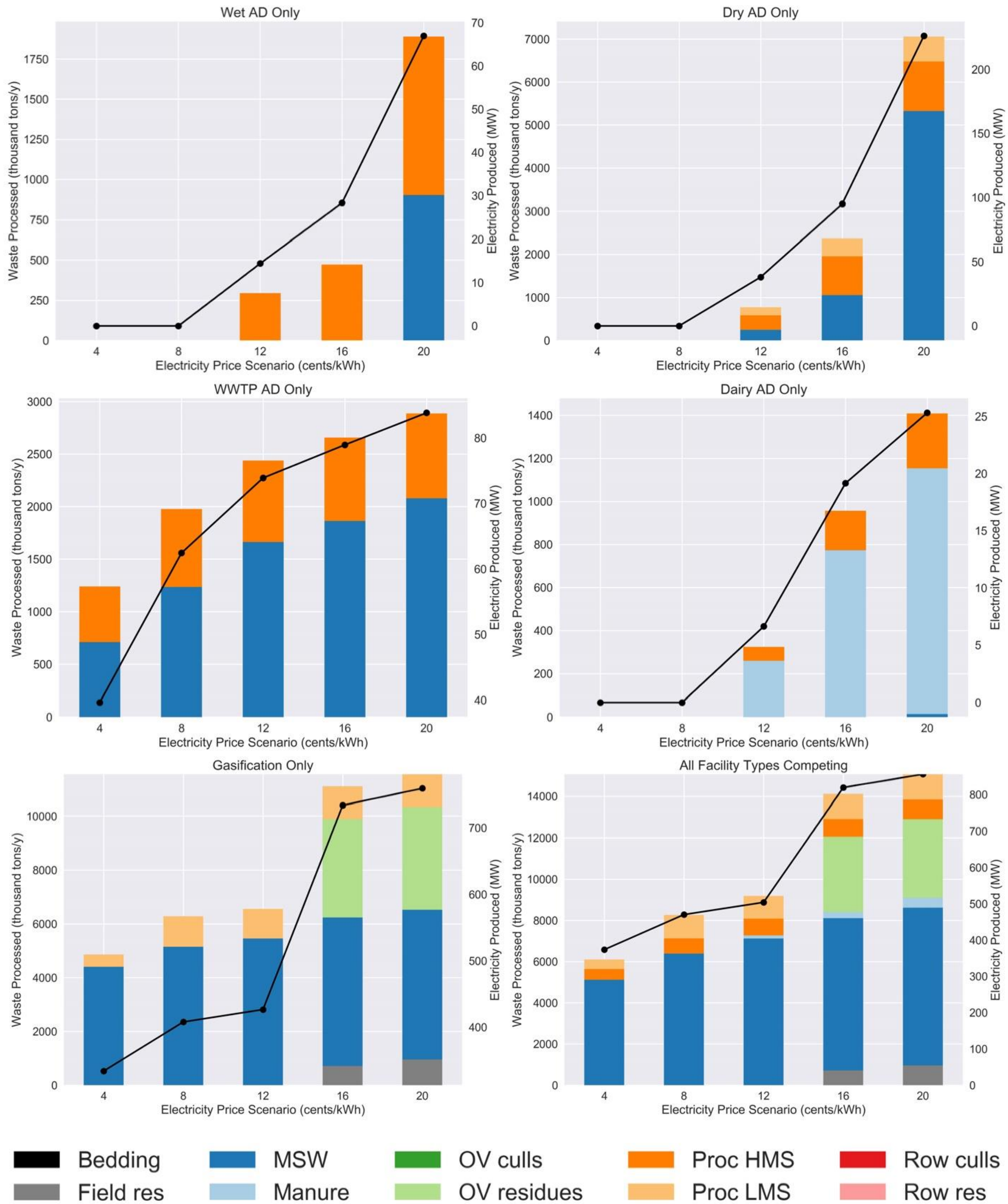
When these facilities compete in 2020, as shown in the "All Competing" scenario (bottom of Table 47 and 48; Table 51), gasification facilities take all technically available low-moisture wastes while WWTP take the high-moisture and liquid waste streams. At higher price points, a small amount of dairy and wet AD also appears. However, significant portions of the waste stream are left unprocessed, namely about half of technically available MSW food waste, 30 percent of processor HMS, and essentially all FOG, dairy manure, and row crop culls and residues. In 2050, dry AD is able to take up some a significant amount of MSW food, such that only 25 percent is left unprocessed, however in order to do so it must pay for row residues to meet the dry waste fraction requirements, as the valuable dry MSW and processing wastes are sent to more profitable gasification facilities first. Wet wastes are left unprocessed as the greedy, profit-maximizing formulation of the model concentrates the highest-value wastes at the cheapest facilities, namely WWTP. WWTP capacity is limited, however, and by the time there is no more room at WWTP there aren't enough high-value wastes streams close enough together to justify stand-alone wet or dry AD facilities. Future work will assess re-formulating the model to distribute high-value wastes in such a way that waste processed is maximized, while still ensuring profitability. However, for this strategy to be implemented in practice, outside intervention through municipal waste contracts or state policies would likely be required.

A map of the waste conversion results at the highest electricity price point for 2020 is shown in Figure 46, and for 2050 in

Figure 47. As expected, wet, dry, and WWTP AD facilities are concentrated in urban areas, where the majority of high-value waste and WWTP infrastructure is located. Dairy facilities are in the state concentrated in the Central Valley, with a couple along the southern border. Gasification facilities cover almost the entirety of the state, as they process urban and agricultural wastes at the 20 c/kWh price point. These are the only facilities that reach the northernmost parts of the state.

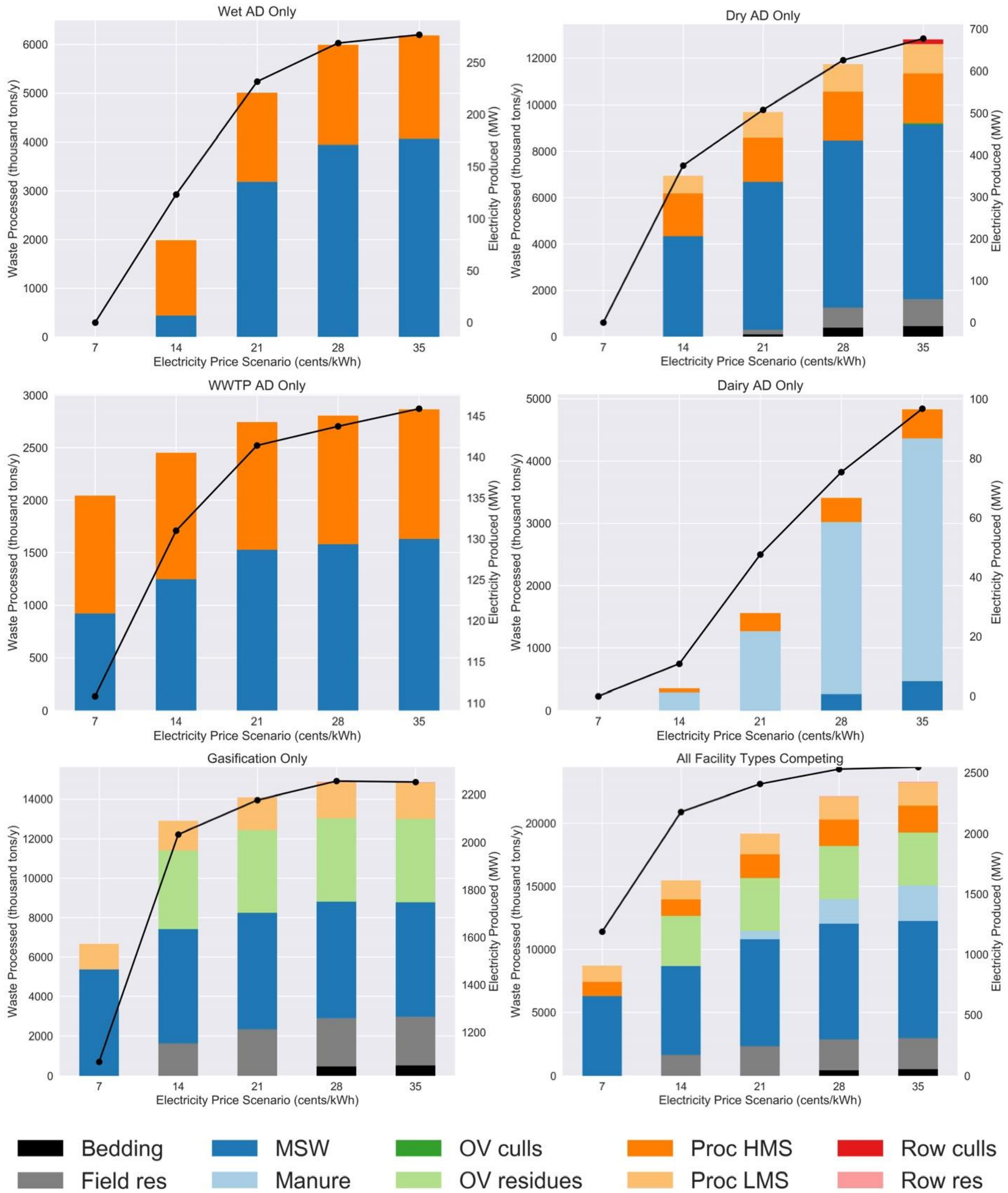
Finally, results for 2050 biogas, biomethane, and syngas generation scenarios are shown in Figure 50. These results inform the modeling done in the district energy network (DEN) techno-economic analysis by showing the quantities of each of these energy projects that could be produced state-wide at various price points. For biomethane scenarios, where the resulting gas is assumed to be injected into the pipeline network, all digestion facility types are possible, whereas for the biogas case, the stand-alone wet and dry AD facilities are only included and not WWTP or dairy co-digestion as these would not be co-located near new DEN developments. The syngas scenario only includes gasification facilities. Syngas and biogas scenarios will over-estimate the potential for co-locating these facilities at DEN sites, as all solid waste handling sites are included as feasible locations and still have a maximum facility size of 400,000 tonnes per year, which may not always be feasible in co-location designs. However, these results give us an understanding of what prices DENs may need to pay to consume these renewable energy types. As shown, biogas generation is limited to around 5 billion cubic feet (Bcf) of methane content per year at the lowest price point, then jumps significantly to 25-35 Bcf at higher prices. Biomethane results are similar, with production at 12 $/Mcf (approx. 10 Bcf) about a third of that at 24 $/Mcf. Syngas generation shows a similar trend to gasification facilities in the electricity generation scenario, with the lowest two prices generating significant amounts of energy, but a jump occurring at the middle price point when O&V residues begin to be accepted.

Figure 44: Total Waste Processed and Electricity Produced for Six Facility-Type Scenarios and Five Electricity Price Scenarios in 2020



Source: Lawrence Berkeley National Laboratory

Figure 45: Total Waste Processed and Electricity Produced for Six Facility-Type Scenarios and Five Electricity Price Scenarios in 2050



Source: Lawrence Berkeley National Laboratory

Table 47: Total Waste Processed and Electricity Produced for Six Facility-Type Scenarios and Five Electricity Price Scenarios in 2020 – Electricity Generation (MW)

Facility Scenario	4 c/kWh	8 c/kWh	12 c/kWh	16 c/kWh	20 c/kWh
Dairy AD Only	0	0	6	19	25
Dry AD Only	0	0	38	95	225
Wet AD Only	0	0	14	28	67
WWTP AD Only	40	62	74	79	84
Gasification Only	333	408	425	733	758
All Types Competing	373	470	503	819	856

Source: Lawrence Berkeley National Laboratory

Table 48: Total Waste Processed and Electricity Produced for Six Facility-Type Scenarios and Five Electricity Price Scenarios in 2020 – Waste Processed (thousand wet tons per year)

Facility Scenario	4 c/kWh	8 c/kWh	12 c/kWh	16 c/kWh	20 c/kWh
Dairy AD Only	0	0	324	956	1,409
Dry AD Only	0	0	774	2,368	7,057
Wet AD Only	0	0	295	472	1,890
WWTP AD Only	1,239	1,977	2,438	2,656	2,886
Gasification Only	4,862	6,289	6,560	11,103	11,549
All Types Competing	6,101	8,266	9,187	14,125	15,072

Source: Lawrence Berkeley National Laboratory

Table 49: Total Waste Processed and Electricity Produced for Six Facility-Type Scenarios and Five Electricity Price Scenarios in 2050 - Electricity Generation (MW)

Facility Scenario	7 c/kWh	14 c/kWh	21 c/kWh	28 c/kWh	35 c/kWh
Dairy AD Only	0	10	48	76	96
Dry AD Only	0	374	507	626	678
Wet AD Only	0	123	232	269	276
WWTP AD Only	111	131	142	143	146
Gasification Only	1,078	2,033	2,176	2,255	2,254
All Types Competing	1,189	2,179	2,406	2,531	2,549

Source: Lawrence Berkeley National Laboratory

Table 50: Total Waste Processed and Electricity Produced for Six Facility-Type Scenarios and Five Electricity Price Scenarios in 2050 – Waste Processed (wet tons per year)

Facility Scenario	7 c/kWh	14 c/kWh	21 c/kWh	28 c/kWh	35 c/kWh
Dairy AD Only	0	352	1,560	3,408	4,828
Dry AD Only	0	6,950	9,691	11,736	12,810
Wet AD Only	0	1,989	5,005	5,993	6,184
WWTP AD Only	2,044	2,452	2,744	2,806	2,864
Gasification Only	6,665	12,904	14,080	14,863	14,852
All Types Competing	8,709	15,466	19,192	22,125	23,259

Source: Lawrence Berkeley National Laboratory

Table 51: Total Percent of Statewide Technical Potential Waste Processed for Each Facility-Type and Electricity Price Scenario (2020)

Scenario		Percent of Waste Type Processed												
		MSW						Processor		Crops				Manure
Facility Types	Price (c/kWh)	Cardboard	FOG	Food	Green	Lumber	Paper	HMS	LMS	Row culls	Row res	Field res	OV res	Dairy
Dairy AD	12							5						1
	16							14						3
	20			<1				19						5
Dry AD	12			2	1		39	25	13					
	16			9	14		68	67	27					
	20			68	78		87	85	39			<1		
Wet AD	12							22						
	16							35						
	20			24				73						
WWTP AD	4			19				39						
	8			32				55						
	12			43				58						
	16			49				59		<1				
	20		3	54				60		<1				
Gasification	4	86			73	85	86		31					
	8	94			89	95	94		76					

Scenario		Percent of Waste Type Processed												
		MSW						Processor		Crops				Manure
Facility Types	Price (c/kWh)	Cardboard	FOG	Food	Green	Lumber	Paper	HMS	LMS	Row culls	Row res	Field res	OV res	Dairy
	12	97			97	97	97		74					
	16	99			98	99	99		81		<1	32	94	
	20	99			99	99	99		81		<1	43	98	
All Competing	4	86		19	73	85	86	39	31					
	8	94		32	89	95	94	55	76					
	12	97		43	97	97	97	61	74					1
	16	99		49	98	99	99	64	81	<1	<1	32	94	1
	20	99	3	54	99	99	99	70	81	<1	<1	43	98	2

Source: Lawrence Berkeley National Laboratory

Table 52: Total Percent of Statewide Technical Potential Waste Processed for Each Facility-Type and Electricity Price Scenario (2050)

Scenario		Percent of Waste Type Processed														
		MSW						Processor		Crops					Manure/Ag	
Facility Type Scenario	Price (c/kWh)	Cardboard	FOG	Food	Green	Lumber	Paper	HMS	LMS	Row culls	Row res	Field res	OV Culls	OV res	Dairy	Bedding
Dairy AD	14							3							1	
	21			<1				13							5	
	28		2	6				18							10	
	35		3	10				21							14	
Dry AD	14			44	67		85	85	42							
	21			78	82		90	88	60			8				18
	28			91	90		96	96	64		<1	35	3	<1		72
	35			96	92		97	98	69	26	30	48	36			84
Wet AD	14			9				71								
	21			68				84								
	28			85				94								
	35			87				97								
WWTP AD	7			20				52								
	14			27				55								
	21			33				56								

Scenario		Percent of Waste Type Processed																
		MSW						Processor		Crops					Manure/Ag	
Facility Type Scenario	**Price (c/kWh)**	**Cardboard**	**FOG**	**Food**	**Green**	**Lumber**	**Paper**	**HMS**	**LMS**	**Row culls**	**Row res**	**Field res**	**OV Culls**	**OV res**	**Dairy**	**Bedding**
	28			34				56								
	35		11	35				57								
Gasification	7	95			83	96	95		71			95				
	14	99			93	99	99		82		<1	99		95	67	
	21	100			97	100	100		89		9	100		99	96	<1
	28	100			97	100	100		98		59	100		100	99	88
	35	100			93	100	100		99		65	100		100	100	99
All Competing	7	95		20	83	96	95	52	71			95			67	
	14	99		27	93	99	99	60	82		<1	99		95	96	
	21	100		55	97	100	100	87	89		9	100		99	99	<1
	28	100	15	70	97	100	100	95	99		60	100		100	100	82
	35	100	6	75	93	100	100	98	99		88	100		100		99

Source: Lawrence Berkeley National Laboratory

Table 53: Total Percent of Statewide Technical Potential Waste Processed for All Facilities Competing – Electricity Generation 2020 Scenario at Five Electricity Price Points

Price scenario (c/kWh)	Facility Type	MSW						Processor		Crops				Manure
		Cardboard	FOG	Food	Green	Lumber	Paper	HMS	LMS	Row culls	Row res	Field res	OV res	Dairy
4	WWTP			19										
	Gasif.	86			73	85	86		31					
8	WWTP			32				55						
	Gasif.	94			89	95	94		76					
12	WWTP			43				58						
	Gasif.	97			97	97	97		74					
	Dairy							3						1
16	WWTP			49				59		<1				
	Gasif.	99			98	99	99		81		<1	32	94	
	Dairy							5						1
20	WWTP		3	54				60		<1				
	Gasif.	99			99	99	99		81		<1	43	98	
	Dairy			<1				7						2
	Wet AD							3						

Source: Lawrence Berkeley National Laboratory

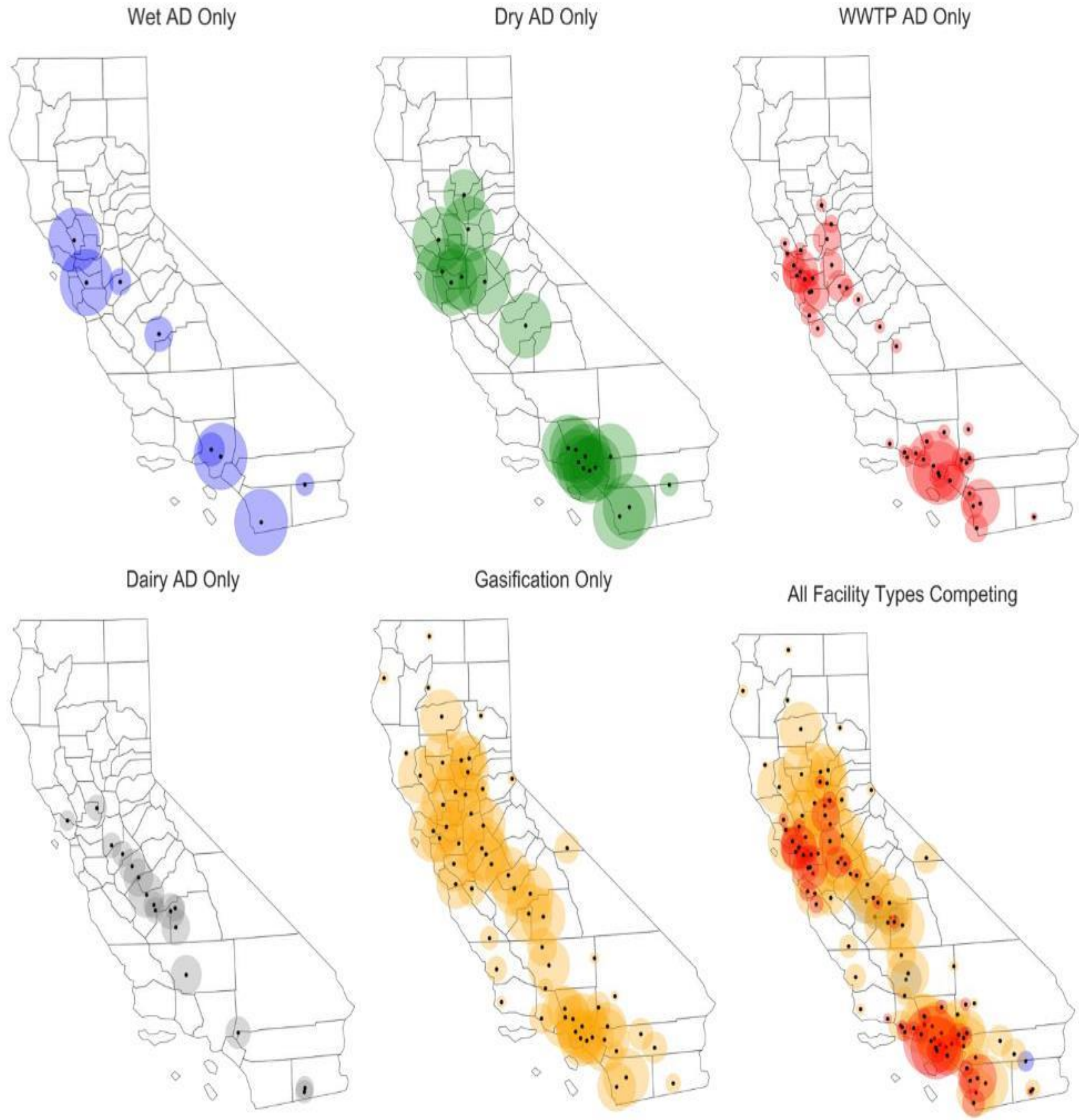
Table 54: Total Percent of Statewide Technical Potential Waste Processed for All Facilities Competing – Electricity Generation 2050 Scenario at Five Electricity Price Points

Price scenario (c/kWh)	Facility Type	MSW						Processor		Crops				Manure/Ag	
		Cardboard	FOG	Food	Green	Lumber	Paper	HMS	LMS	Row culls	Row res	Field res	OV res	Dairy	Bedding
7	WWTP			20				52							
	Gasif.	95			83	96	95		71						
14	WWTP			27				55							
	Gasif.	99			93	99	99		82		<1	67	95		
	Wet AD							5							
21	WWTP			32				56							
	Gasif.	100			97	100	100		89		9	96	99		<1
	Wet AD			2				18							
	Dry AD			21	<1		<1	6	<1						
	Dairy			<1				7						2	
28	WWTP		13	34				56							
	Gasif.	100			97	100	100		98		59	99	100		82
	Wet AD			3				25							
	Dry AD			27	<1			6	1		1	<1			
	Dairy		2	6				8						7	
35	WWTP			34				56							

Price scenario (c/kWh)	Facility Type	MSW						Processor		Crops				Manure/Ag	
		Cardboard	FOG	Food	Green	Lumber	Paper	HMS	LMS	Row culls	Row res	Field res	OV res	Dairy	Bedding
	Gasif.	100			93	100	100		99		65	100	100		99
	Wet AD			4				27							
	Dry AD			26				6	<1		23	<1			
	Dairy		6	11				9						10	<1

Source: Lawrence Berkeley National Laboratory

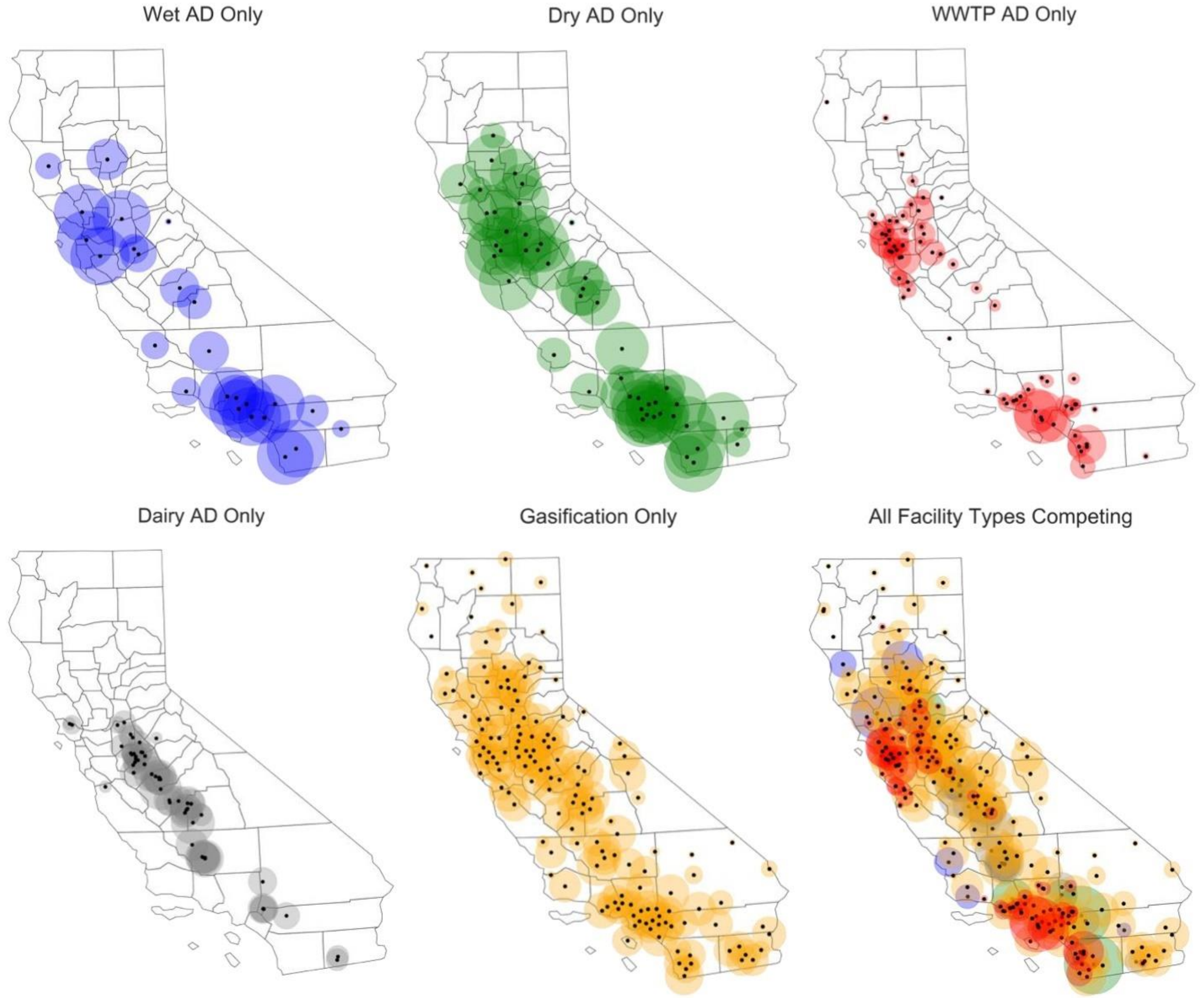
Figure 46: Location and Relative Size of Built Facilities for Six Facility-Type Scenarios at an Electricity Price of 20 c/kWh in 2020



Red = WWTP co-digestion facility; green = dry AD facility; blue = wet AD facility; grey = dairy AD facility; yellow = gasification facility. Size of circle represents relative quantity of waste intake.

Source: Lawrence Berkeley National Laboratory

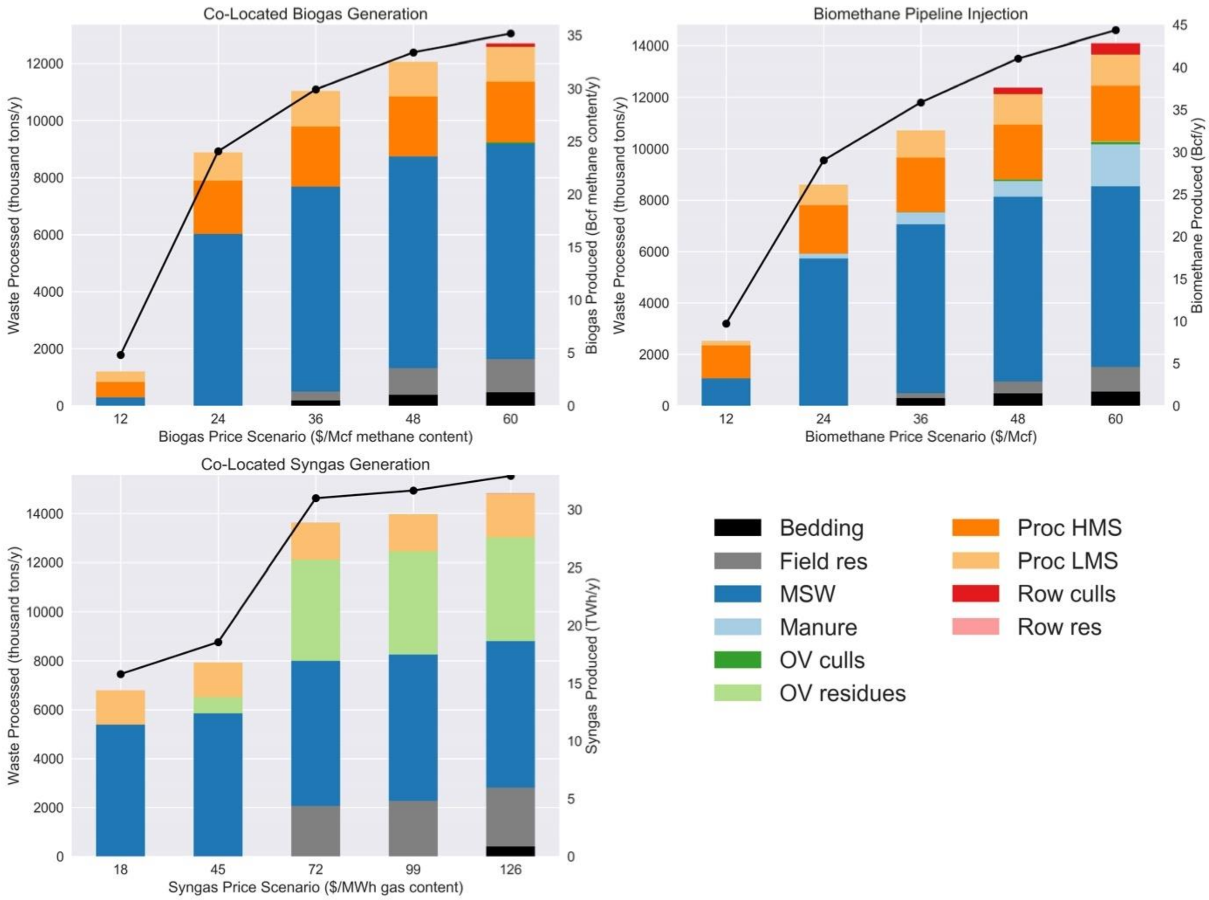
Figure 47: Location and Relative Size of Built Facilities for Six Facility-Type Scenarios at an Electricity Price of 35 c/kWh in 2050



Red = WWTP co-digestion facility; green = dry AD facility; blue = wet AD facility; grey = dairy AD facility; yellow = gasification facility. Size of circle represents relative quantity of waste intake.

Source: Lawrence Berkeley National Laboratory

Figure 48: Total Waste Processed and Energy Produced for Three Energy Product Scenarios at Five Price Points



Source: Lawrence Berkeley National Laboratory

5.3.2 District Energy Cost Model

While the waste conversion model described above quantifies the amount of biomethane, biogas, and syngas that is economically feasible at various price points, the district energy cost model assesses the economics of district energy networks (DEN) and associated energy generation and supply assets utilizing these energy products to generate and sell energy in the form of electricity, heat, and cooling.

There are approximately 25 cost and revenue categories in the model. To calculate the net present value (NPV) of each scenario, "baseline" costs are calculated for each of these categories first, as described in the following sections. These costs either represent an up-front cost for capital or a single year cost for fuel, labor, and maintenance. These costs are then projected into a 30-year cash flow assuming they are either inflating annually at a rate of 2 percent, or if capital, paid off over 10 years at a finance rate of 8 percent. Interest payments, depreciation (using the MACRS 7 schedule), and taxes (assuming a 21 percent federal and 8.8 percent state tax rate) are then calculated for the 30-year cash flow. Finally, all costs are discounted to present date using a discount rate of 10 percent. Results are shown in terms of "amortized annual cost", which is essentially the net present value of the given cost category averaged over the DEN's assumed 30-year lifetime.

5.3.2.1 District Energy Scenarios

Five hypothetical DEN sites across California were modeled, reflecting the five climate zones in which large-scale mixed-use development sites are anticipated (as outlined in Chapter 3). These systems are defined by their heating and cooling demand, peak heating and cooling loads, and the associated equipment capacities needed to serve them. System definition also includes the quantities of energy (electricity, cooling, and heat) that they consume and/or sell. Key metrics are shown in Table 55. Costs for these systems built in 2050 are modeled.

Table 55: Key Site Metrics for DEN Cost Modeling

Metric	CHP Type	Bay Area	Central Valley	LA	N. Central Valley	San Diego
CHP Electrical Capacity (kW)	SIGE	11,157	5,331	6,694	6,198	6,694
	Fuel Cell	9,396	18,649	12,150	16,038	8,424
Abs. Chiller Capacity (kW)	SIGE	6,351	3,034	3,811	3,528	3,811
	Fuel Cell	10,005	19,665	12,938	17,078	8,970
Peak Heating Load (kW)	--	32,429	31,714	30,396	36,178	34,741
Peak Cooling Load (kW)	--	13,382	40,885	34,502	27,090	20,291

Source: Lawrence Berkeley National Laboratory

Each of these DEN sites is modeled under numerous scenarios. "New District Energy" (N-DE) scenarios involve the investment in a complete DEN as a new development is being built, fueled by either biomethane from the natural gas pipeline network, biogas piped from a co-located anaerobic digestion facility, or syngas piped from a co-located gasification facility. For each of these fuel types use of a spark-ignited gas engine (SIGE) or fuel cell (FC) for combined heat and power (CHP) generation is assessed.

The team also modeled the economics of existing DEN wanting to incorporate consumption of biomethane into their operations. Biogas and syngas are not considered for these scenarios, as it is unlikely that new waste handling operations would be built within the existing urban environment. The "Existing - Fuel Switch" (E-FS) scenario represents a DEN with SIGE CHP that wishes to switch from using fossil natural gas to biomethane through a purchasing contract, while the "Existing – New CHP" (E-NC) is for an operating DEN that currently uses natural gas boilers and electric chillers to supply thermal loads, but wishes to switch to a biomethane-fueled SIGE or FC CHP unit.

Each of the scenarios described is run for all five DEN sites, for three fuel price points; this results in a total of 150 cases. Additionally, there are two non-district energy scenarios for new developments at each of the five sites, which estimate the cost of supplying the required energy demands with separate plants located in each building using either fossil fuels (N-FF) or renewable energy (N-RE).

5.3.2.1 Capital Costs

Capital costs included in the model are summarized in Table 56. All district energy scenarios include capital for the heating and cooling piping networks, CHP units, absorption chillers that utilize CHP waste heat to provide cooling, electrics chiller that can use CHP electricity or grid power to provide additional cooling, and gas boilers for back-up and additional capacity when CHP capacity is not sufficient to meet heating demands. The N-FF scenario includes gas boilers and electric chillers for each building in the site, while the N-RE scenario provides heating and cooling in each building via heat pumps. For the fuel switching scenario (E-FS), no capital costs are impacted. For E-NC, it is assumed the DEN already has gas boilers and electric chillers, but will need to install an absorption chiller to use waste heat in addition to the new CHP unit.

Table 56: Capital Costs Included in Various DEN Scenarios

Capital Costs	New Systems: District Energy	New Systems: Fossil Fuels	New Systems: Renewable Energy	Existing Systems: New CHP
Network cost	X			
CHP	X			X
Absorption chiller	X			X
Gas boiler	X	X		
Electric chiller	X	X		
Heat pump			X	
Construction, engineering, and installation	X	X	X	X

Source: Lawrence Berkeley National Laboratory

Network costs include piping to distribute hot and chilled water to each building in the network, heat exchangers needed to connect each building's internal heating and cooling systems to the network piping, and operational costs for the network over its lifetime. These costs are calculated using assumptions summarized in Section 3.4.1 (Network Model) of this report. These costs are forecasted to 2050 using the California' Construction Cost Index (California Department of General Services 2019) for capital costs, which shows exponential growth of approximately 2.5 percent annually, and Bureau of Labor Statistics Employment Cost Index (ECI) (exponential 2.1 percent annually) for maintenance costs (U.S. BLS 2019a).

The five sites require CHP capacity of 5-11 MW. A DEN will likely install 2-3 generator units to meet the desired capacity in order to account for maintenance, unexpected downtime, and to better run the generators closer to their full load. Over this narrow range of approximately 2-4 MW, CHP costs are can be assumed to scale linearly with rated capacity; the current-year unit cost assumed is $1,800/kW for SIGE generators (IEA-ETSAP 2010) and $4,600/kW for fuel cells. SIGE costs are forecasted to 2050 using the Producer Price Index (PPI) for non-vehicle internal combustion engines, which results in 2050 costs equal to 1.34 times current costs in nominal dollars (U.S. BLS 2019b). Fuel cell costs are forecasted according to 2030 projections and technology learning assumptions described in Section 5.3.1.3. Interestingly, these two forecasts result in SIGE and FC engines having approximately the same cost in 2050 (2400 and 2500 $/kW, respectively). For biogas scenarios, both engine types are de-rated by 10 percent to account for differences between biogas and natural gas combustion, based on an analysis of Innio (formerly General Electric) Jenbacher engine specification sheets (Innio 2019). Similarly, SIGE engines running on syngas are de-rated 25 percent (Bates and Dölle 2017). For SIGE combusting biogas or biomethane, an additional cost for the selective catalytic converter (SCR) is added and assumed at $305 per kW of CHP electrical capacity. Absorption chillers are sized based on the high-grade heat capacity of the CHP units, and similarly costs are assumed to be linear with a current unit cost of $280/kW (MGE 2019; U.S. DOE 2017), which are forecasted to 2050 using the PPI for HVAC and refrigeration equipment, resulting in 2050 nominal prices equal to 1.41 times current values (U.S. BLS 2019b).

Gas boilers and electric chillers are sized based on peak heating and cooling loads, respectively, and sized up 20 percent for contingency. For the non-district energy scenario, the average peak load for each individual connection on the DEN site is taken and size the boilers and chillers accordingly. Therefore, in the non-DE scenario, instead of one set of boilers at X kW capacity, there are N sets of boilers at X/N kW capacity, where N is the number of connections. Exponential curves with a scaling factor of 0.8 are used for gas boiler and electric chiller capital costs, so that the economies of scale between district energy and non-district energy systems can be adequately captured. For natural gas boilers, the reference point of $42,650 is used for an 800 kBtu/h boiler to calculate the parameters for the cost curve (EIA 2018). For electric chillers, $250,000 is used for a 500-ton chiller (MGE 2019). Boiler and electric chiller costs are forecasted using the PPI for boilers and HVAC/refrigeration equipment, respectively, resulting in 2050 cost multipliers of 1.52 and 1.41 (U.S. BLS 2019b).

In the renewable energy scenario, the heat pumps must be sized to meet the peak of heating or cooling demand, whichever is greater. If the cooling load is greater, the capacity an additional 25 percent is scaled up to account for the hot water demands that must be met even during times of peak cooling. A unit cost of $1,350/kW capacity is then assumed (EIA 2018), which is forecasted to 2050 using a multiplier of 1.23 based on the heat pump PPI (U.S. BLS 2019b). Lastly, construction, engineering, and installation costs are estimated as 15 percent of the total capital costs for the given scenario.

Capital costs for the plant room are not included in the model. Commercial floorspace value varies widely across California, and the actual value of the space typically used for plant rooms (basements, rooftops, etc.) is very difficult to quantify. However, the plant room space saved in individual buildings by having a centralized district energy plant may be significant. For example, a 6-building development was estimated to require 48,600 square feet for individual plant rooms (5,400-10,800 per building), as opposed to 16,200 square feed for a centralized utility plant, plus 1000-sqft exchange rooms in each of the buildings connected to the network (Calven and Naqvi 2014).

5.3.2.2 Operating Cost

Operating costs included in the model are summarized in Table 57. In general, fuel and maintenance costs are included for each relevant equipment type in the scenario, and incremental fuel and maintenance costs are included for existing systems for any piece of equipment whose load is impacted.

Table 57: Operating Costs Included in Various DEN Scenarios

Operating Costs	New Systems: District Energy	New Systems: Fossil Fuels	New Systems: Renewable Energy	Existing Systems : New CHP	Existing Systems : Fuel Switch
CHP fuel	X			X	X*
CHP maintenance	X			X	
Absorption chiller maintenance	X			X	
Boiler fuel	X	X		X*	
Boiler maintenance	X	X		X*	
Electric chiller fuel	X	X		X*	
Electric chiller maintenance	X	X		X*	
Heat pump fuel			X		
Heat pump maintenance			X		
Labor	X	X	X		

*** Incremental costs (positive or negative) only**

Source: Lawrence Berkeley National Laboratory

Fuel for the CHP is either biogas, biomethane, or syngas depending on the scenario. For each fuel type, three price levels used in the waste conversion model in the previous section are modeled. That way, the results of the two models can be compared to assess (1) how much of the energy product could profitably be produced at the given price and (2) the feasibility of utilizing the energy produce in DEN at the given price. For biogas and biomethane, 2050 prices of 12, 24, and 36 $/1000scf of methane are modeled, which translates to 40, 80, and 120 $/MWh of fuel energy content. For syngas, 18, 45, and 72 $/MWh of fuel content are used. These are the low, medium-low, and medium prices modeled in the waste conversion model for each fuel type. Considerable bioenergy is feasible at these price points, and there are decreasing marginal returns to total production at higher prices. The prices chosen aim to cover expected energy market prices on the low end, and on the high end, prices that could reasonably be achieved through a mix of energy prices, consumer renewable energy mark-ups, and monetary environmental incentives such as carbon pricing.

The quantity of fuel needed is the desired CHP energy production divided by the efficiency. For biomethane SIGE and FC, electrical efficiency is 40.4 percent and 42.5 percent, respectively, while biogas generators are assumed to be 2 percentage points lower in efficiency (Innio, 2019). The combustion of syngas in an SIGE generator has an efficiency of 25 percent (Caputo et al. 2005), while fuel cells operating directly on syngas are assumed to have the same efficiency as methane at 42.5 percent (Bang-Møller et al. 2011, El-Emam and Dincer 2015).

Boiler fuel is needed to serve heating loads that are not met by the CHP waste heat. The typical fossil natural gas is assumed to be used for the boilers in all cases. While biogas and biomethane could also be used for the boilers, there may not be adequate environmental incentives to do this like there typically are for electricity generation end-uses. Additionally, the DEN operator may want to secure a lower quantity of renewable fuel to solely be used for consistent CHP operation, and rely on grid fossil fuels for additional peaking loads. The average California commercial customer natural gas price in 2017 of $8.64 per 1000 cubic feet (EIA 2019b), and 80 percent energy efficiency is used. Similarly, electric chillers are used when the CHP waste heat and absorption chillers cannot meet all of the cooling load. If CHP units are operating, CHP electricity is used for this purpose. When this option is not available, grid electricity is purchased to power the chillers, at the average California commercial electricity price of 16 cents/kWh (EIA 2019a), and a performance coefficient of 6 is assumed. These prices are each forecasted to 2050 using the Annual Energy Outlook (AEO) (EIA 2019c). For existing system new CHP scenarios, electric chiller and boiler fuels are a negative cost as the system will save money in these areas relative to a case where they don't install a CHP unit.

The heat pumps in the renewable energy scenario are assumed to have a COP of 3.7 for heating and 5 for cooling, and to also run off of grid electricity at the average commercial electricity price. Historically, consumers may have needed to pay a premium for renewable electricity, but at current California solar energy prices, and by making direct long-term purchase contracts with the renewable energy generator, an entity may actually have a lower price than the retail rate (Bolinger and Seel 2018).

Maintenance costs are estimated for each equipment type. As mentioned, network maintenance costs are included in the lifetime capital cost inputs. In general, maintenance costs are estimated per kWh of energy delivered by the equipment. Current price assumptions are: 0.5 cents/kWh for CHP and absorption chillers each, 0.2 cents/kWh of fuel energy content for SCR, 0.4 cents/kWh for heat pumps (EIA 2018), and 0.3 cents/kWh for boilers and electric chillers each. All of these costs are forecasted to 2050 based on the ECI for operations and maintenance (U.S. BLS 2019a).

Labor costs are included for all new systems, and are assumed to not be significantly impacted in the existing system scenarios. Similar to plant room costs, the labor rate will vary widely across California. A moderate rate of $60,000 was used for the fully-burdened cost for one full-time equivalent (FTE) employee, forecasted to 2050 based on the ECI. A California Energy Commission report estimated 11 FTE required for 6 buildings operating independent thermal plants (Calven and Naqvi 2014); therefore, it is estimated the number of FTE needed for the 40-building sites under non-district energy scenarios is 73, with the labor scaling linearly to the number of buildings connected. The same report estimated 6.5 FTE for the centralized district energy system serving six buildings with 4,900 tons of chiller capacity and 30 MMBTu/h of boiler capacity. These sites require 4,500-14,000 tons of chiller capacity and 125-150 MMBtu/h of boiler capacity; scaling labor linearly would mean approximately 8-20 FTE required for the sites. While the team does not assume moderate economies of scale for labor required, the district energy sites also include CHP units (not present in the Energy Commission's report), and therefore estimate FTE of 8-15 for the sites, depending on the total amount of load served (and therefore equipment present).

5.3.2.3 Energy Revenues

The district energy system recoups its capital and operating costs by selling energy. Thermal energy in the form of heating and cooling is sold to the occupants and/or owners of the buildings connected to the network, while electricity generation not used for the operation of the system (namely, the electric chillers) is sold to the electricity grid. It is assumed thermal energy prices of 3.5 cents/kWh for heating and 2.7 cents/kWh for cooling based on price per unit of thermal energy equal to that of the conventional base case scenario, and these are forecast to 2050 based on the AEO natural gas price forecast.

The price obtained for selling electricity to the grid will vary widely depending on the customer and contract structure of the electricity. The DEN operator may choose to enter a power purchase agreement (PPA) with an individual energy consumer or consumer choice aggregator (CCA) interested in procuring renewable energy. Examples of each of these options have been seen in the context of wastewater treatment plants generating excess electricity: East Bay Municipal Utility District sells power directly to the neighboring port of Oakland for $58/MW (Hake et al. 2017), while Central Marin Sanitation Agency has a PPA with Marin Clean Energy, a CCA, for approximately $105/MW (CMSA 2018). If selling to one of California's major Investor-Owned Utilities (IOU), the DEN would be able to obtain a wholesale price for electricity, which generally ranges from $40-60/MWh in California (EIA 2019), plus any value from renewable energy credits. Another option for the facility would be to enroll in the bioenergy feed-in tariff (BioMAT) program offered by the IOUs, which offers prices of $127-197/MW to small bioenergy producers. However, the current program is scheduled to sunset in 2021, and only generators below 5 MW are eligible (CPUC 2018). Taking all of this into consideration, a current value of $100/MW for electricity sales is used, which is again forecasted based on AEO electricity price projections. This would include both the power sales revenue and additional revenue obtained from environmental incentives, whether that be renewable energy credits, a feed-in-tariff similar to BioMAT, or others.

5.3.2.4 Results

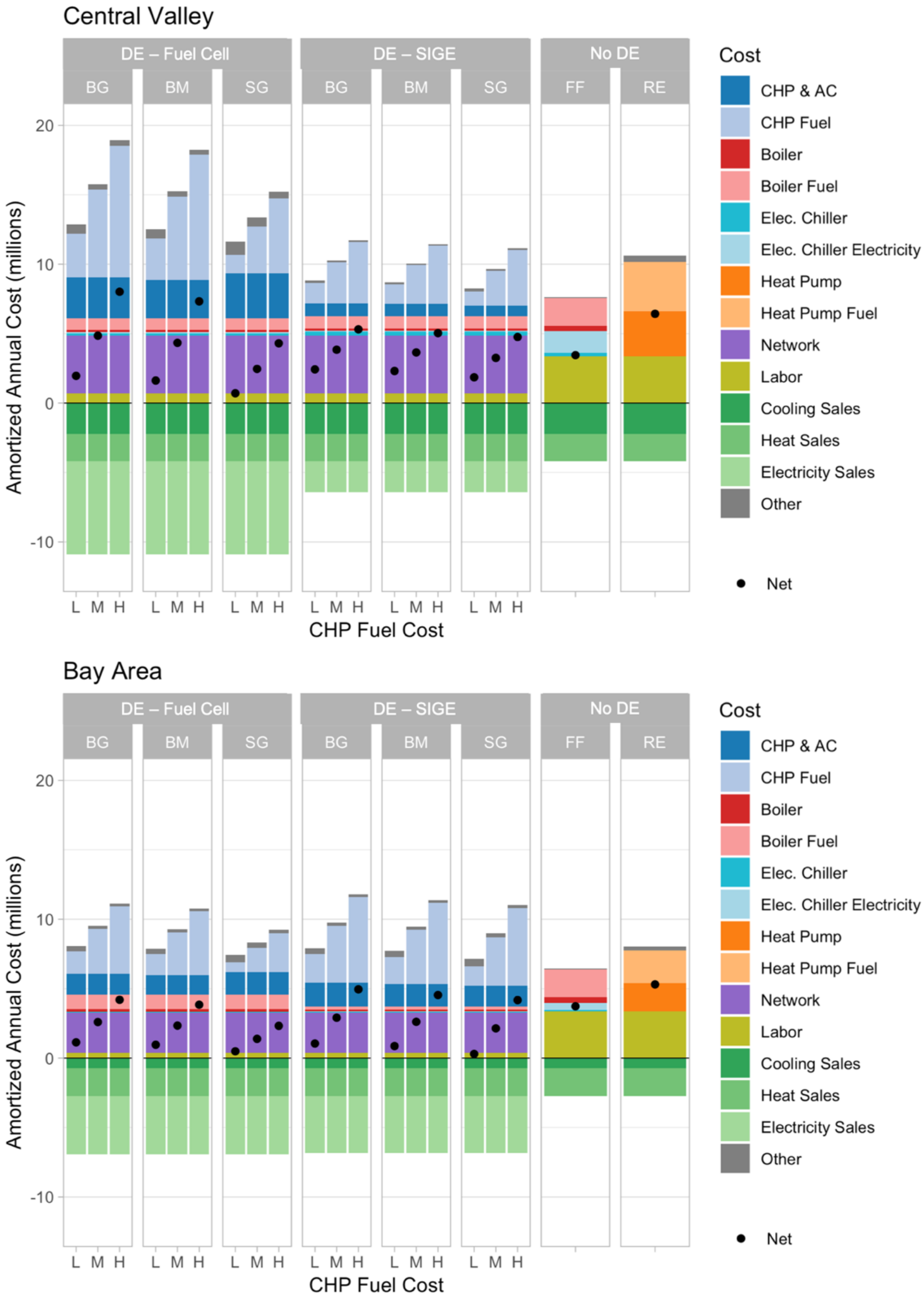
New system scenario results for DEN sites in Central Valley and the Bay Area are shown in Figure 49. The Bay Area site has the lowest thermal energy demands of the five systems modeled, while the Central Valley site has the largest loads. For the SIGE scenarios, this does not necessarily give an expected result, with the Bay Area site shown to support larger CHP engines than other locations. This is due in large part to a less seasonal climate, whereby there is sufficient summer heating load to support large engines (which are supplying cooling via high grade heat offtake) without dumping heat. Installed capacity for fuel cells across climate zones are a broad reflection of thermal load conditions. A subset of results for the remaining sites are provided in Figure 50 and net present value results for all scenarios in all five climate zone sites are given in Table 58.

For each DEN scenario there is a low, medium, and high fuel cost scenario, according to the fuel price assumptions described above. All systems at all sites have negative net present value (NPV) except for one, meaning the costs of supplying energy to the buildings in the development site are higher than the energy revenues assumed. DEN systems generally cost less than the baseline non-DE (N-FF and N-RE) scenarios at low fuel prices modeled, are similar to the baseline N-FF at medium prices, and slightly lower than all-electric non-district energy (N-RE) scenarios at high fuel prices except for Central Valley fuel cells. In all locations, the lowest-cost system is a DEN operating a fuel cell on direct syngas at low prices, though in the Bay Area the SIGE on low-cost syngas is roughly the same cost. Labor cost savings for DE scenarios are significant, but they are offset by the cost to install and maintain the network piping system. Heating and cooling sales are equal in each energy scenario for a given site, as are electricity sales for all CHP scenarios for a given site and generator type, as these values are defined by the DEN site.

For new DEN installing SIGE generators, outcomes are nearly identical regardless of fuel type. This is because the much lower efficiency of syngas combustion is offset by the relatively lower syngas prices, which were modeled due to the abundant syngas generation found to be possible at these lower prices in the waste conversion model. In the fuel cell cases, where energy efficiency is the same across fuels, lower syngas prices make these systems more attractive. Milder climates are better-suited to fuel cell applications due to the lower CHP and absorption chiller capacities and fuel consumption required to meet cooling demands.

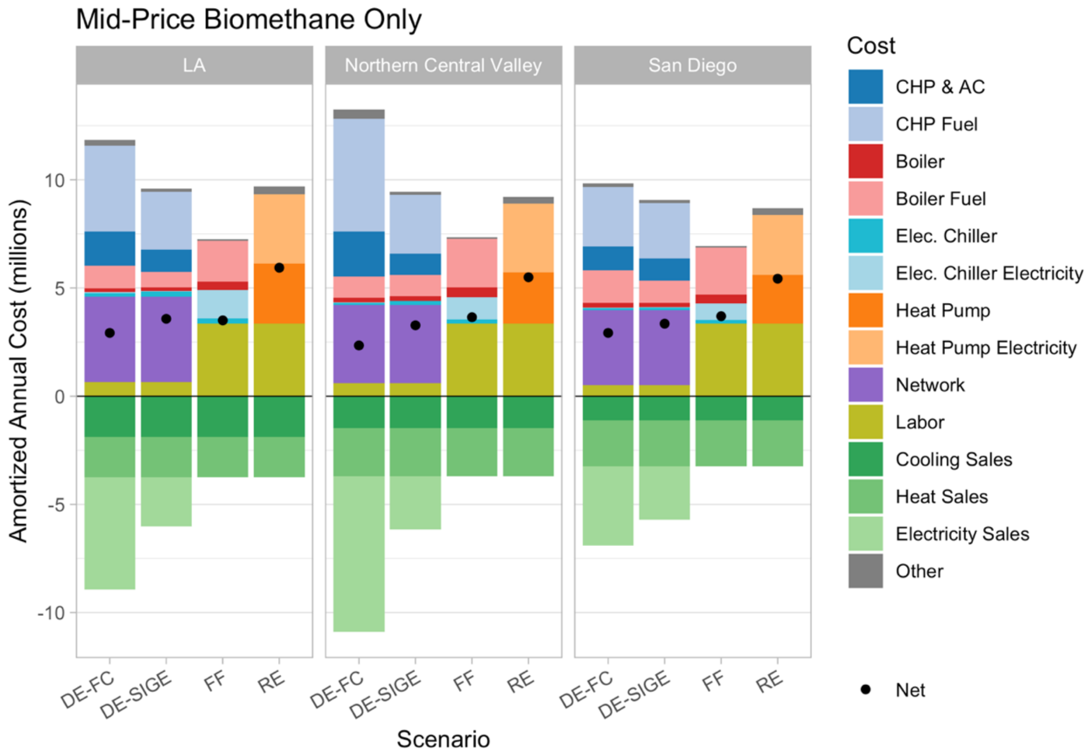
Lastly, results for the existing system scenarios are shown Figure 51. Note that these results are for making changes to a hypothetical existing system, and the baseline is different across the two scenarios. In the fuel switch (E-FS) scenario, the baseline is a DEN operating an SIGE engine that establishes a contract to utilize biomethane. Projected 2050 grid natural gas prices are roughly equivalent to the "medium" biomethane cost studied, and therefore the "low" cost scenario yields savings while the high cost comes at a cost of 2-5 $M/y depending on the site. The new CHP scenario (E-NC) shows the costs of installing an SIGE or CHP unit to operate on biomethane in a fossil-fueled district energy system that is currently running centralized natural gas boilers and electric chillers. In this scenario, the savings to electric chiller and boiler fuel and maintenance along with electricity revenues offset the costs of CHP fuel and installation, except at the highest biomethane prices. Even at high biomethane prices, net costs are less than $600,000/year, or less than 0.6 cents per kWh of thermal energy served, except in the Central Valley fuel cell case ($2.1 M/y, 1.6 cents/kWh) and Bay Area SIGE case ($1.1 M/y, 1.4 c/kWh) due to the higher equipment capacities required as described above.

Figure 49: 2050 Costs and Revenues for New DEN in Two California Regions



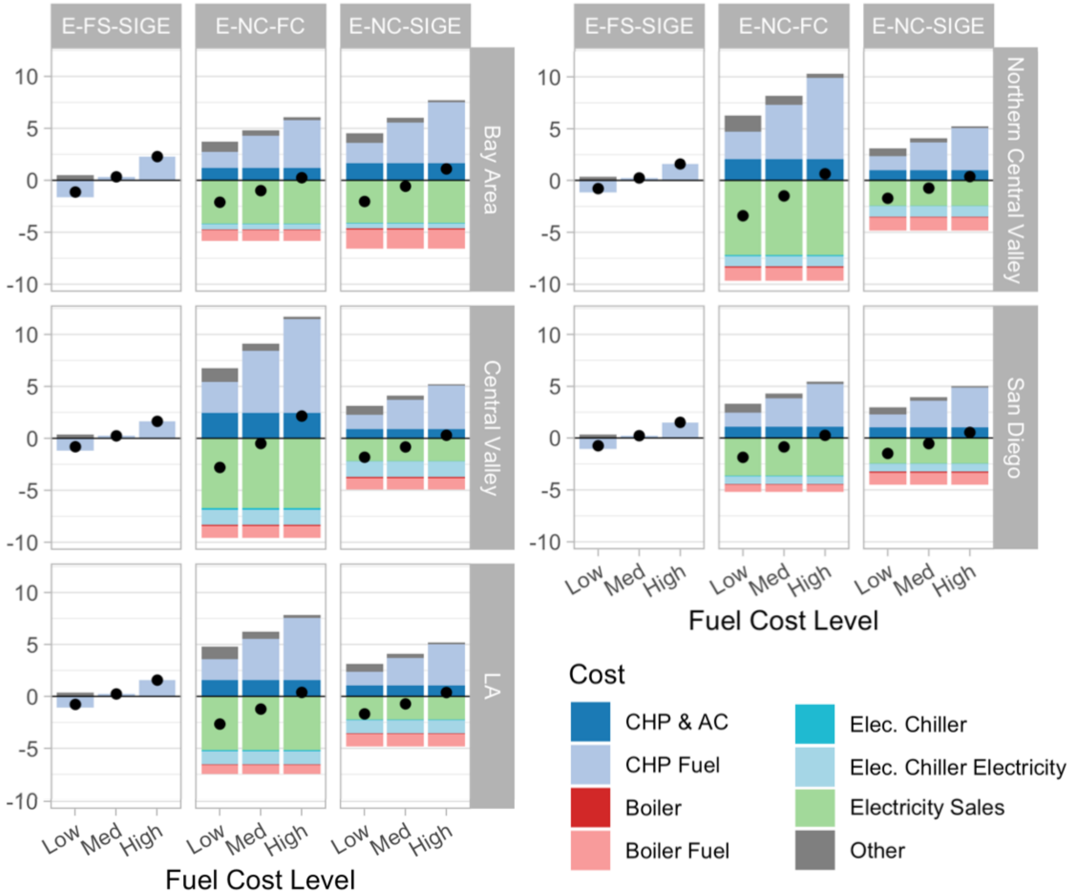
Source: Lawrence Berkeley National Laboratory

Figure 50: 2050 Costs and Revenues for a Limited Set of New DEN Scenarios in Three California Regions



Source: Lawrence Berkeley National Laboratory

Figure 51: 2050 Costs and Revenues for Hypothetical Existing DEN Making Changes to Incorporate Biomethane Into Their Operations



Source: Lawrence Berkeley National Laboratory

Table 58: NPV of Thermal Energy System for Five Locations in California

Scenario	Generator	Fuel	Fuel Cost	Net Present Value ($M)				
				Bay Area	Central Valley	LA	N. Central Valley	San Diego
N-DE	Fuel Cell	Biogas	Low	-34	-59	-50	-22	-60
			Med	-78	-146	-106	-95	-101
			High	-126	-241	-168	-175	-145
		Biomethane	Low	-29	-49	-43	-13	-56
			Med	-70	-130	-96	-82	-94
			High	-115	-220	-155	-157	-135
		Syngas	Low	-15	-21	-25	10	-42
			Med	-42	-74	-59	-34	-67
			High	-70	-129	-96	-81	-93
	SIGE	Biogas	Low	-32	-73	-73	-63	-67
			Med	-87	-115	-113	-104	-106
			High	-149	-159	-155	-147	-147
		Biomethane	Low	-26	-69	-69	-60	-63
			Med	-79	-109	-107	-98	-101
			High	-136	-151	-147	-139	-139
		Syngas	Low	-9	-56	-56	-47	-51
			Med	-64	-98	-96	-87	-90
			High	-125	-143	-140	-131	-132
N-FF	--	--	--	-112	-104	-105	-109	-111
N-RE	--	--	--	-159	-193	-178	-165	-163

Source: Lawrence Berkeley National Laboratory

5.4 Policy and Regulatory Incentives and Barriers

5.4.1 Zero-Waste Policies

California has very aggressive waste diversion goals that are motivated by the need to reduce food waste and short lived climate pollutant emissions from landfills. For example, AB 1826 is a mandatory commercial organics recycling law requiring businesses and multifamily housing to divert solid waste and solid organic waste from landfills based on weekly waste production.

The target is a 50 percent reduction by 2020 of solid organic waste disposal. It should be noted that multifamily housing is not required to divert food waste.

A number of recent bills have been enacted or proposed to support organic waste diversion targets. In particular, SB 1382 sets a 50 percent reduction target for methane emissions in California by 2020 from 2014 levels, and 75 percent reduction target by 2025. AB1036 would require assessment of the state's composting and organic processing infrastructure and its expansion to support waste diversion. AB 2411 would require upward revision of the allowable amount of compost that can be used for slope stabilization and for use along roads and in cities.

5.4.2 Electricity Grid Interconnection

Getting a interconnection between a net positive energy producer that could sell its electricity and the local electrical utility can be a major challenge. The utility dictates the required equipment installations and costs, which can be upwards of a million dollars depending on the existing grid infrastructure near the generation site. Understanding these requirements and being able to negotiate the costs requires significant electric power system expertise, either in-house or by hiring a consultant.

Multiple structures exist to allow the sale of electricity to the grid.

- BioMAT - offers a higher rate than wholesale and even retail prices, ZWEDC was first facility to enroll, took them 9 months with a hired consultant expert, from talks w/ CPUC they are trying to improve this process, high penalties for not meeting generation forecasts, only for smaller generators (max 3 MW)
- Self-consumption/Net metering
- Direct sale to customer w/ wheeling fee (e.g. EBMUD) - not sure if there are any significant incentives or challenges here
- Wholesale market

5.4.3 Biogas Injection into Natural Gas Pipelines

At the national level, biogas qualifies for both the Renewable Fuel Standard (RFS). Under the RFS, Renewable Identification Numbers (RINs) for biogas generated from anaerobic digestion fall under cellulosic RINs or advanced biofuel RINs

In California, landfill gas, biogas and biomethane are currently regulated under a number of senate bills (SB) and assembly bills (AB):

- AB 1900 - in 2012, this bill lifted restrictions on the use of landfill gas, with biogas quality standards developed as a result
- AB 2313 - provides a financial subsidy up to $3 million for new dairy biomethane pipeline interconnections
- SB 1043 - requires the development of a lifecycle accounting method for GHG and SLCP associated with the conversion of forestry waste to biogas and biomethane

In California, biogas used as a transportation fuel qualifies for sale under the Low Carbon Fuel Standard (LCFS). Under the LCFS, sellers of fuels with high carbon intensities, such as diesel and gasoline must either reduce their carbon intensity or purchase offset credits. As biogas from organic wastes has a lower carbon intensity, it has a high value on the credit market.

The construction and operation of pipelines is based on department of transportation approval, easement, and permitting, as well as individual utility gas standards.

5.4.4 Extension of District Energy Systems with CHP

Listed below are issues pertinent to the development of district energy projects that have value or cost associated with them but are not included in the techno-economic analysis. This is because they are outside of the scope of the project, require a level of site specificity that is not allowed for here, or because there is a level of variability or uncertainty, or lack of consensus on their value that could obscure other meaningful results and conclusions. Nevertheless, they remain significant issues for consideration for CHP/district energy projects.

5.4.4.1 Incentives

Technical

- Consistent with building greater grid resilience and local energy supply security
- Further future proofing of local communities
  - Flexible to future technology retrofits
  - Flexible to future urban densities and forms

Commercial / Financial

- Central planning and resourcing of operation and maintenance
- Release of space previously occupied by building thermal plant in individual buildings
- Building owners able to offer 'green' work space on rental / leasing market
- Offset spending on new fossil fuel / electrical cooling plant in individual buildings at the time of life expiry
- Increased commercial energy sales opportunities
  - Increase in quantum of thermal energy sales
  - Sales of electricity

Regulatory

- Reduction in global emissions due to offsetting of large utility plant generation
- Decarbonization of existing building stock and greening of the grid

Other

- Local employment in construction and administration during project implementation.
- Public relations around commitment toward sustainability
  - Contributions to emissions targets
  - Taking existing building to LEED
- Potential for local / community control

5.4.4.2 Barriers

Technical

- Capacity on electrical distribution networks for connection of new generation
- Retrofitting pipe infrastructure into existing urban environments
    - Logistics and wayleaves
    - Cost (partly related to logistics above)
- Physical obstacles to installation of networks (natural or man-made)
- Mothballing / expiry of natural gas transmission infrastructure

Commercial / Financial

- Capital cost of cogen plant and thermal distribution networks
- Incompatible schedule plant replacement for plant replacement in local buildings
- Cost of connection / reinforcement of local electricity distribution networks
- Risks associated with unfamiliar business models (for entities not currently operating in the electricity generation market)
- Contracting new customers due to low priority / limited value proposition of green energy
- Ensuring extensions do not negatively impact existing customers
    - Service interruption
    - Rate increases
- Biogas cleaning to meet the necessary standards for injection into the gas network
    - Capital cost
    - Operating cost
    - Regulatory uncertainty
- Cost of delivered fuel

Regulatory

- Increase in local emissions associated with greater fuel consumption from cogeneration

Other

- Public relations around local air quality issues

5.4.5 Construction of New District Energy Systems

5.4.5.1 Incentives

Technical

- Consistent with building greater grid resilience and local energy supply security
- Future proofing of development
    - Fuel flexible
    - Prime mover flexible
    - Compatibility with other thermal renewable energy sources

- Islanding of critical operations due to on-site generation and storage
- Significant resource in demand response market
    - Flexible, fast start electricity generation technologies
    - Thermal storage operations compatible with grid flexibility needs
    - On-site building resources

Commercial / Financial

- Gross space needs for plant reduced compared to base cases
- Central planning and resourcing of operation and maintenance

Regulatory

- Reduction in global greenhouse gas emissions
- Where there is potential for new networks to connect to existing buildings, decarbonization of existing building stock

Other

- Potential for local / community control

5.4.5.2 Barriers

Technical

- Security / seasonality of fuel supply
- Mothballing / expiry of natural gas transmission infrastructure
- Physical obstacles to installation of networks (natural or man-made)
- Improved case for alternative renewable energy options

Commercial / Financial

- Capital cost of cogen plant and thermal distribution networks
- Cost of delivered fuel
- Competition for fuel resources from other sectors (i.e. transport)
- Uncertainty of final development build-out characteristics and associated uncertainty of required investment and revenue

Regulatory

- Increase of local emissions associated with relatively greater fuel consumption from cogeneration as compared to base cases

Other

- Public relations around local air quality issues

5.4.6 Air Quality Permitting and Regulations

In addition to meeting policy and regulatory criteria, and energy related permits for electricity grid interconnections and/or pipeline interconnections, the construction of a new project must go through a multitude of permitting processes. These include California Environmental Quality Assessments (CEQA). Existing sources of waste organics that want to perform onsite utilization of their bioenergy may also face unexpected challenges associated. For example, biomass residues generated at the Bariani Olive Oil Farm are olive pits, pomace, and tree trimmings. The trimmings are shredded and applied to the farm's land along with the pomace, while the pits dried, stored, and combusted for thermal energy as they do not readily degrade in the field. Despite being able to supply all space and water heating from the combustion of pits, the farm had to pay for two miles of electricity lines to be run as an interconnection because of a law requiring the facility to have centralized HVAC (electric central heater and furnace for water heating).

5.4.6.1 Discharge/Effluent Handling

Storm water discharge permitting falls under the National Pollution Discharge Elimination System (NPDES) under the Clean Water Act.

5.4.6.2 Operations

Solid waste typically falls under state regulations for Industrial and Individual types. Facilities must obtain permits for non-hazardous and hazardous materials, for composting, and for waste discharge.

5.4.6.3 Air Quality and Runoff

These permits fall under the Clean Air Act for construction, fugitive emissions, and point sources like pumps, flares, and boilers. A facility must obtain permits for construction and operation. The overall DG emissions and future deployment of DG technologies in California are subject to emission regulations formulated by CARB and local air quality management districts. CARB certifies DG engines that are under 1 MW and meeting its emission standards. The units that are greater than 1 MW typically undergo permitting process with local air districts and are subject to Best Available Control Technology (BACT) guidelines. BACT guidelines require the implementation of best control technologies possible that are proven in practice or those that are available without significant economic burden.

5.4.6.4 Land Use/ Building/ Zoning

These permits usually fall under state and local regulations for construction in incorporated places. Criteria includes, building height and materials, distance to other structures and roads. Urban development is constrained by zoning laws, that can vary significantly even within a city. Some aspects of zoning laws in the building stock turnover model are captured by placing caps on the size replacement buildings can be.

CHAPTER 6: Overview of Waste-to-Energy Matching Tool

6.1 Introduction

The goal of the waste-to-energy matching tool is to provide the ability for rapid evaluation of potential Waste-to-Energy sites, including retrofits/expansions of existing facilities or entirely new construction, on the basis of resource availability and potential for waste heat utilization. This requires high-level data for users who wish to survey the whole state for resource-rich regions of interest, as well as very refined data for users who have one or more specific sites in mind and plan to reach out to specific haulers or organic residue-producing locations/entities.

6.2 Target Stakeholders

Targeted users/stakeholders include:

- Public policy-makers
- Research institutions
- Investors
- Bioenergy producers
- Operators of existing facilities
- Waste haulers
- Organic residue sources (e.g. food processors, wineries, breweries, farmers)

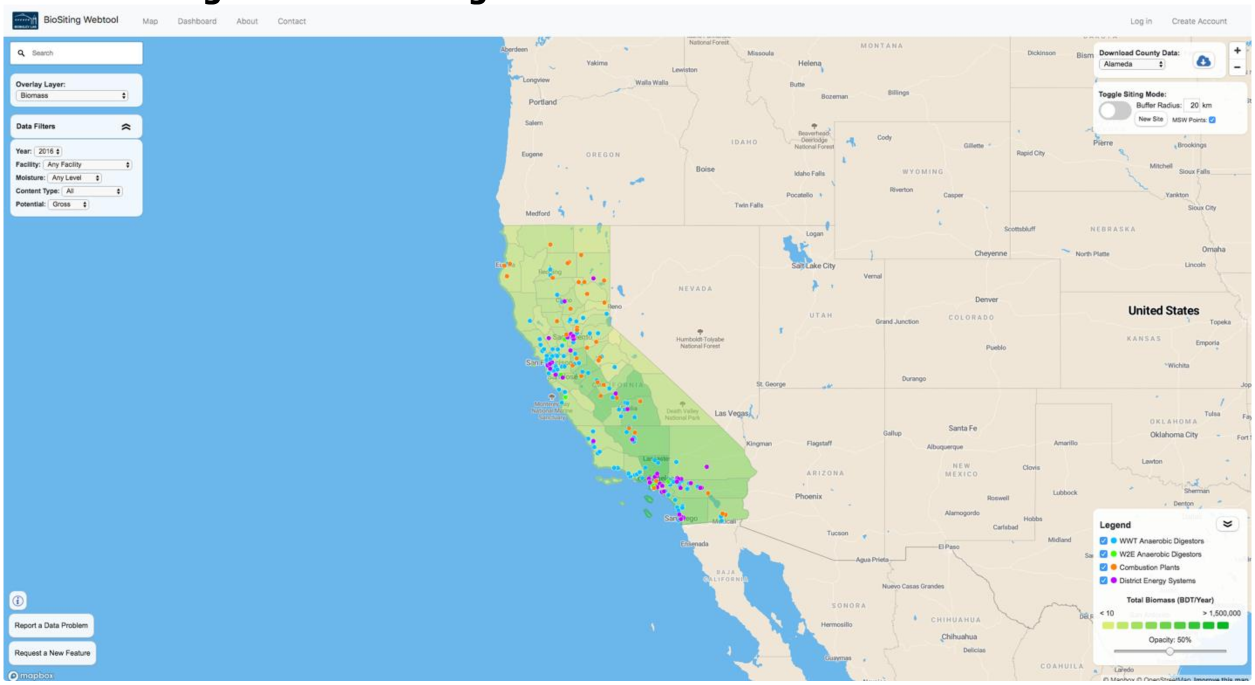
The team provided demonstrations of the tool to a wide variety of researchers, industry stakeholders, policy-makers, and investors to gather feedback on the functionality and what additional features would make it more useful and relevant in the current policy and economic environments. This includes the technical advisory committee (TAC), the organizing committee for the California Bioeconomic Summit (including the Air Resources Board, CAL FIRE, and numerous other leaders in the field), the project partners at Allotrope Partners, and numerous startups working with the Advanced Biofuels (and Bioproducts) Process Demonstration Unit. The feedback received has been enormously valuable and wherever possible has been incorporated into the tool.

6.3 Tool Structure

The tool is web-based, using a Javascript front end and Python backend. It is hosted at https://biositing.jbei.org/california.

Figure 52 shows a screenshot of the tool, as loaded when a user first visits the site. The tool loads points including existing bioenergy/wastewater treatment facilities and a partially transparent choropleth map showing organic waste resources by county. All data are available for 2014, 2020, and 2050 scenarios.

Figure 52: Biositing Tool Screenshot – General Structure

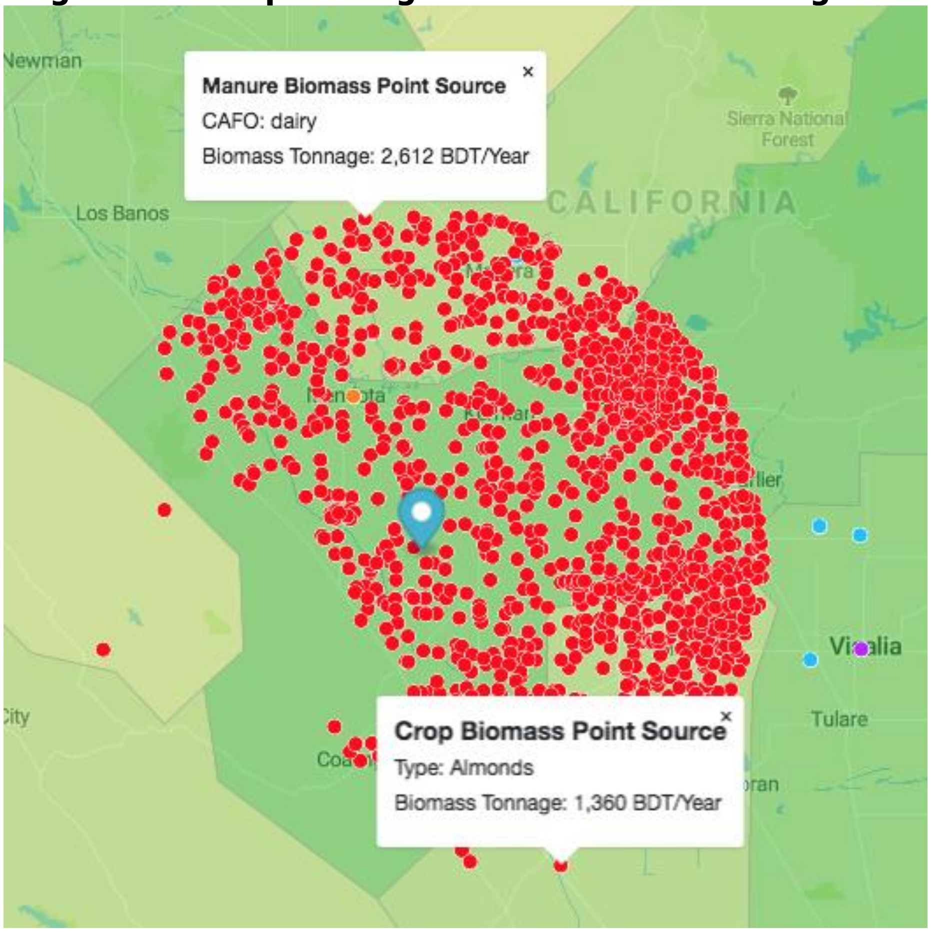


Source: Lawrence Berkeley National Laboratory

The tool allows users to filter biomass data shown based on moisture content, compatibility with thermochemical vs. anaerobic digestion processes (which is generally correlated with moisture content), herbaceous vs. woody feedstocks, and gross potential vs. technical potential (where the latter removes waste that is already used in other markets such as animal feed). Users may also filter out municipal solid waste, if the process of interest cannot handle mixed waste with significant inorganic contamination.

Toggling "Siting Mode" allows the user to selecting a specific site and see individual biomass supply points, with additional details about the type of biomass and annual supply. By setting the buffer distance, users may establish the maximum Euclidian distance away from the selected site that is of interest for possible feedstock supply. By clicking on individual red points, the user can see details for each biomass supply point. In cases where the biomass type is an agricultural residue, the Cropland Data Layer provided by the USDA is used, run through a k-means clustering algorithm to approximate centroids of residue supply. Hence, the locations will not be exact, but rather will be the centroids of small clusters of land classified for a specific agricultural product (e.g. almonds). Figure 53 is an example of the siting mode results. Users may also download results for either the buffer established in Siting Mode, or results for an entire county, which will include further detail about seasonal availability and composition.

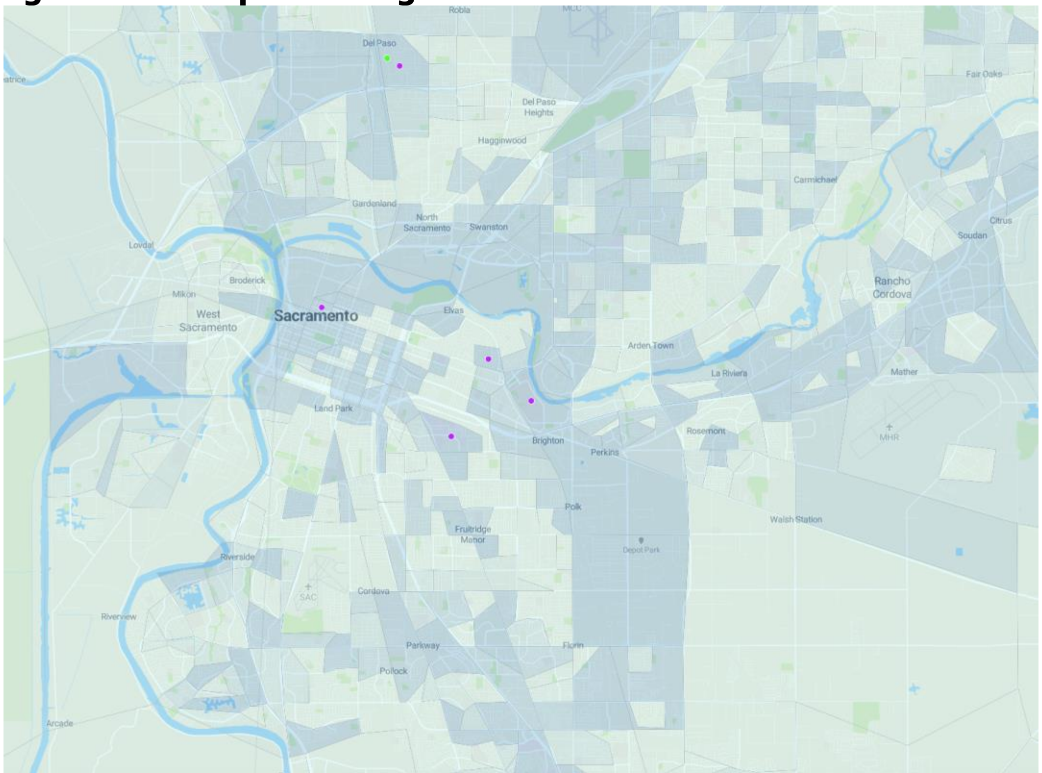
Figure 53: Sample Siting Mode Results in Biositing Tool



Source: Lawrence Berkeley National Laboratory

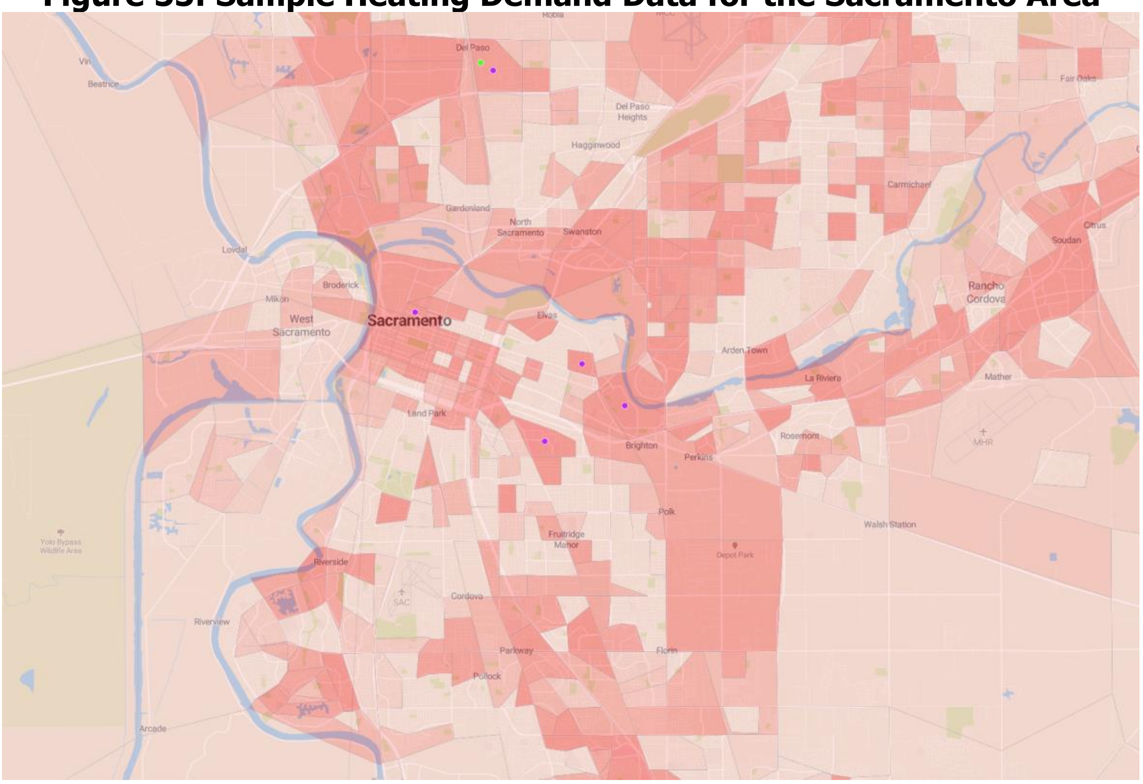
In instances where users are interested in building distributed generation facilities paired with district energy systems (or finding a specific facility that is able to utilize waste heat), the tool also offers thermal energy demand mapping functionality. Thermal energy demand is split into heating and cooling, and is based on detailed modeling conducted using parcel-level building data and energy use intensities from the California Energy Commission. The building stock turnover model, discussed in more detail in earlier chapters, provides the basis for future projections (combined with updated EUIs). Figure 54 and Figure 55 provide samples of the data accessible in the tool for cooling and heating demand in the Sacramento Area.

Figure 54: Sample Cooling Demand Data for the Sacramento Area



Source: Lawrence Berkeley National Laboratory

Figure 55: Sample Heating Demand Data for the Sacramento Area



Source: Lawrence Berkeley National Laboratory

6.4 Illustrative Case Studies

6.4.1 PepsiCo

The non-alcoholic beverage industry consumes large amounts of water, and while soft drinks (i.e. soda), enhanced water, sports drinks, and juices are predominantly comprised of water, as low as 20-30 percent of water consumed by a facility leaves as product (Comelli et al 2015). Equipment and bottle washing is estimated to make up the majority of wastewater produced by the industry (Abdel-Fatah et al 2017), but wastewaters containing high chemical oxygen demand (COD) levels due to sugar content are also produced when product is discarded or returned from market. This can occur due to changes in market demand, loss of gas content or exceeded expiration date, spills, or from routine manufacturing processes.

PepsiCo Performance with Purpose 2025 goals include a 25 percent improvement in water-use efficiency with a focus on water reuse and proper wastewater management in high-water-risk areas. Additionally, PepsiCo has made a commitment to reducing absolute greenhouse gas (GHG) emissions by 20 percent by 2025 (PepsiCo).

In this case study, LBNL partnered with PepsiCo to provide an analysis of the liquid and solid wastewater generated at PepsiCo facilities, and provide both recommendations on best practices for waste biomass-to-energy adoption, and a clearer understanding of how biomass usage can further the PepsiCo Performance with Purpose 2025 goals. The company provided information for two different mixed beverage waste types derived from expired products and concentrated waste streams (not typical wastewater that are more dilute). were Viable options for utilizing waste biomass were determined and compared with current practices to assess opportunities for lowering costs and environmental impacts based on the data provided by PepsiCo. To do this, a techno-economic analysis (TEA) model for anaerobic digestion was applied to determine the cost of generating biogas from (1) an anaerobic digestion (AD) system located at the PepsiCo facility, (2) a stand-alone AD system, and (3) co-digestion at a wastewater treatment facility in the nearby region. The LCA model is used to conduct an attributional analysis of GHG and non-GHG emissions from a baseline wastewater management scenario, and an onsite wet-AD scenario for the concentrated and dilute waste streams.

The following data was provided by PepsiCo:

- Volume: 10,000 gallons per day
- Assume that waste is currently being sent to local WWTP, diluted with other waste water
- The beverage waste solution is between 4 percent w/w sugar (normal strength) and 50 percent w/w sugar (concentrated stream). (4g sugar/100g solution and 50 g sugar/100g solution).
- Mostly sugar: 1 percent solids = 12,000 ppm COD
- Assume a 45 percent glucose, 55 percent fructose breakdown which was approved by PepsiCo
- Assume an ambient temperature for waste streams which was approved by PepsoCo: 25C +/- 10

For a future full analysis, the LBNL team determined the following properties were critical for estimating key metrics, including cost, net GHG emissions, net criteria air pollutants, and net water consumption:

- Location of facilities (address, lat long)
- Biomass waste stream characterization:
    - Types of waste streams (fruit and vegetable residue, wastewater, syrup, sucrose)
    - production (at smallest time interval possible)
    - properties (moisture content, BOD, COD, contaminants, TDS, sugars, starches, cellulose, hemicellulose, lignin, incombustible minerals)
    - details on waste storage and transportation systems (type of storage and size of storage
    - frequency of processing (incineration, pickup by trucks, flush to sewer)
    - location of final disposal of waste (landfill, wastewater treatment facility, farms)
    - cost of disposal
- Power, heating, and cooling energy consumption to operate building and manufacturing
    - Fuel consumption by end use (heating, cooling, power)
    - Fuel demand by end use (at smallest time interval possible)
    - Peak demand by end use

6.4.1.1 Beverage Waste Processing Cost

The onsite waste beverage processing system includes feedstock handling and short-term storage, anaerobic digestion, onsite energy (electricity) generation, and wastewater/waste sludge treatment/disposal stages. The process model is developed in a modeling software-SuperPro Designer. The simulated onsite waste processing facility uses either normal (sugar concentration of 4 percent by weight) or concentrated (sugar concentration of 50 percent by weight) beverage waste of 10,000 gal/day. Wet (solid loading of 4 percent by weight) or dry anaerobic digestion (solid loading of 50 percent by weight) are considered depending on the concentration of sugar in the beverage waste. In anaerobic digestion, 86 percent of each organic component is converted into biogas (methane and carbon dioxide). The biogas includes 51 percent CH_4 and 49 percent CO_2 on a dry molar basis. Biogas is used to produce electricity in the subsequent energy generation unit.

The material and energy balance data is used to determine the required size of equipment and respective purchasing price, the capital investment, and operating costs. The total capital investment is estimated by incorporating direct fixed capital (DFC), working capital, and start-up costs. An operating cost of one month is assigned as working capital and 5 percent of the total DFC is assigned for start-up cost. In addition to capital investment, the annual operating cost is estimated by incorporating facility-dependent cost (includes maintenance (1 percent of DFC), depreciation (decline balance method), and property taxes and insurance (0.7 percent of DFC), raw materials cost, labor-dependent cost, and cost of utilities. Operator cost of $69/h is assigned in the process model, which includes the basic rate of $30/h, and the sum of benefits, operating supplies, supervision, and administration factor of 0.4, 0.1, 0.2 and 0.6

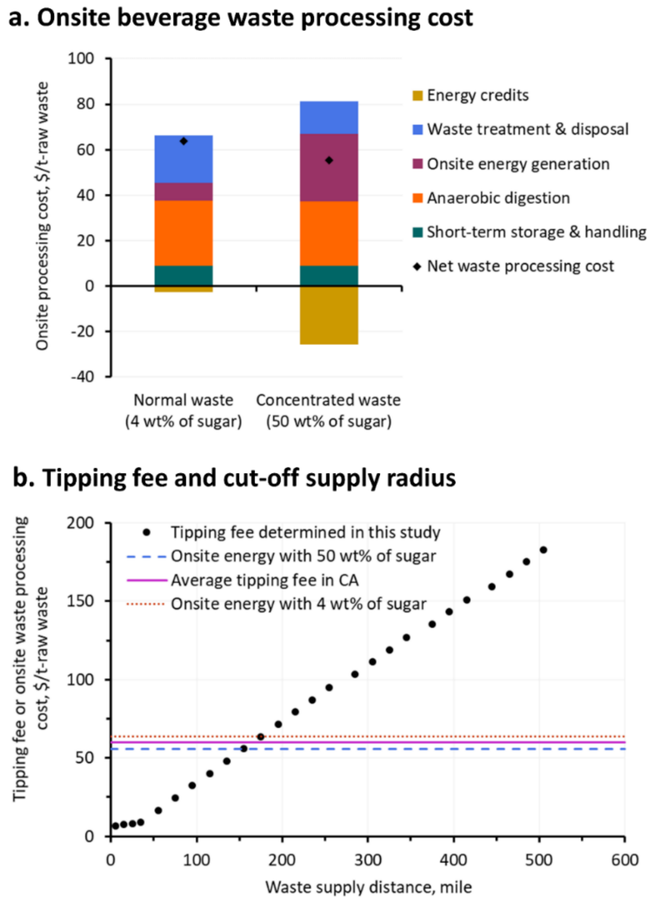
times of the basic rate, respectively. The onsite waste processing facility is assumed to be operated 7920 h (330 days/year and 24 hours/day) for 30 years.

Figure 56(a) depicts the net waste processing cost for both normal and concentrated wastes. For the normal beverage waste, the anaerobic digestion is the major contributor (43 percent) to the total waste processing cost followed by waste treatment and disposal (32 percent), short-term storage and handling (13 percent), and onsite energy generation (12 percent). On the other hand, the onsite energy generation and anaerobic digestion are major contributors to the total concentrated waste processing cost accounting for 37 and 35 percent of the total cost. However, the concentrated waste processing facility generates about 9 times more energy credits when compared to the normal waste resulting in about 13 percent less net waste processing cost.

6.4.1.2 Tipping Fee and Cut-Off Supply Radius

Tipping fee includes loading, unloading, and transportation costs, which is determined considering the waste of 10,000 gal/day is transported via truck. The team determined the loading, unloading, and transportation costs including capital investment, ownership costs (including depreciation, interest, taxes, and insurance), and operating costs (including repair and maintenance, fuel, lubrication, and labor). Figure 56(b) demonstrates the tipping fee over the transportation distances. These results suggest the economic cut-off supply radius could be in the range of 150 to 175 miles.

Figure 56: Onsite Beverage Waste Processing Cost (a) and Tipping Fee (b)



Source: Lawrence Berkeley National Laboratory

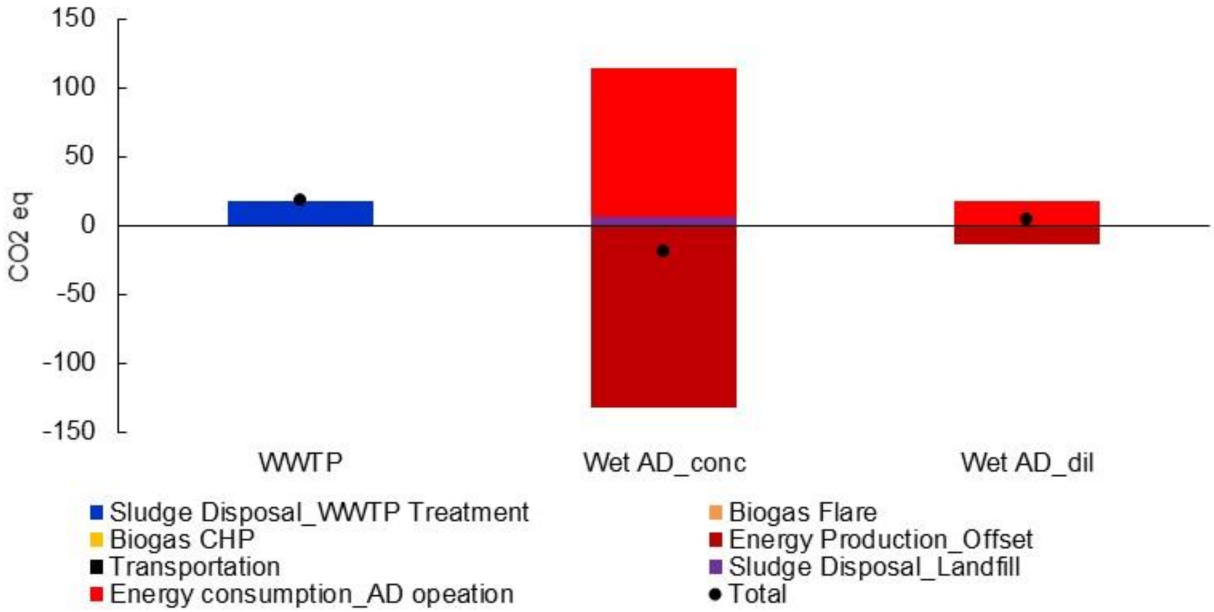
6.4.1.3 Lifecycle Assessment - Methods

In this approach, daily waste (solid and liquid wastewater) from PepsiCo is taken into account to estimate inbound waste at the proposed wet anaerobic digestion facility. As the waste water is generated on site, inbound transportation is omitted. Two scenarios are considered for the two types of waste streams as per the information provided. Concentrated waste stream and diluted waste stream. A third BAU scenario named as WWTP is also assumed considering the treatment of beverage waste sent to wastewater treatment plant for co-digestion without energy production. This can be considered the baseline waste disposal method. At the facility, the waste is fed into dry anaerobic digester with total solid value of 22 to 40 percent (Ward et al. 2008), where the waste materials are kept in airtight chambers chamber to which micro-organisms are added via sprinklers (Di Maria et al. 2017). Electricity required to operate an AD facility is provided by the TEA modeling analysis and is dominated by the air compressor needed to achieve complete combustion of the biogas. Energy consumption for processing the high strength waste is ~8-10 times higher than for the dilute waste stream. Emission rates measured by members of the project team at a dry-AD facility in California are assumed for combined heat and power generation from biogas combustion and biogas flare. Digested sludge is then sent to nearby landfill for disposal. Recalcitrant carbon content of some of the beverage waste does not degrade even after landfill, rather gets sequestered in the landfill offsetting up to 7.5 percent of the methane emissions from landfill (USEPA 2018). Therefore, methane emissions from landfill is estimated considering the carbon sequestered by the landfill. Once the transportation distances (outbound to landfill), biogas produced, flared, vented, electricity produced are estimated, emission rates collected from literature, Ecoinvent database, GREET model and directly measured on site are used to estimate lifecycle environmental emissions (CO_2eq, NO_x, NMVOC, SO_2, CO and $PM_{2.5}$) assuming 30 years life time of the facility. Finally, to interpret the results, lifecycle environmental impacts are analyzed as a function of inbound waste.

6.4.1.3 Lifecycle Assessment Results – GHG emissions

This section presents illustrative results of the LCA analysis for a set of three scenarios namely, ‘WWTP’ (all waste to wastewater treatment facility for treatment without energy generation; baseline scenario), ‘Wet AD conc’ (all concentrated waste is treated onsite in a wet AD facility for biogas and ultimately electricity generation via combined heat and power unit) and ‘Wet AD dil’ (all diluted waste is treated onsite in a wet AD facility for subsequent biogas and electricity production). As expected, treatment of concentrated beverage waste at the anaerobic facility to produce biogas and electricity results in net negative CO_2eq emissions despite expected additional electricity consumption to operate the facility. This is because concentrated waste stream has 50 percent sugar as opposed to 4 percent in case of diluted waste stream that resulted in higher energy generation. Electricity produced from biogas is assumed to offset electricity produced from natural gas which would have otherwise been produced at a natural gas power plant, the primary source of electrical energy in California. As CO_2 emissions from biogas flare and biogas CHP are biogenic, these emissions are not regarded as contributing to a systems lifecycle greenhouse gas emission. In this preliminary analysis, electricity generation from concentrated beverage waste at AD facility seems most attractive from a GHG emission perspective, while sending beverage waste to a wastewater treatment facility seem GHG intensive compared to both AD scenarios (Figure 57). Impacts from landfilling the digested sludge as well as transportation of digested sludge to landfill are minimal. On an absolute scale, the emissions from treating the beverage waste at the waste water treatment facility without power generation is 18 kg CO_2eq/ gallon of waste, which itself is not large compared to landfill emissions (Figure 57).

Figure 57: Lifecycle GHG Emissions from Various Beverage Waste Management Strategies



Source: Lawrence Berkeley National Laboratory

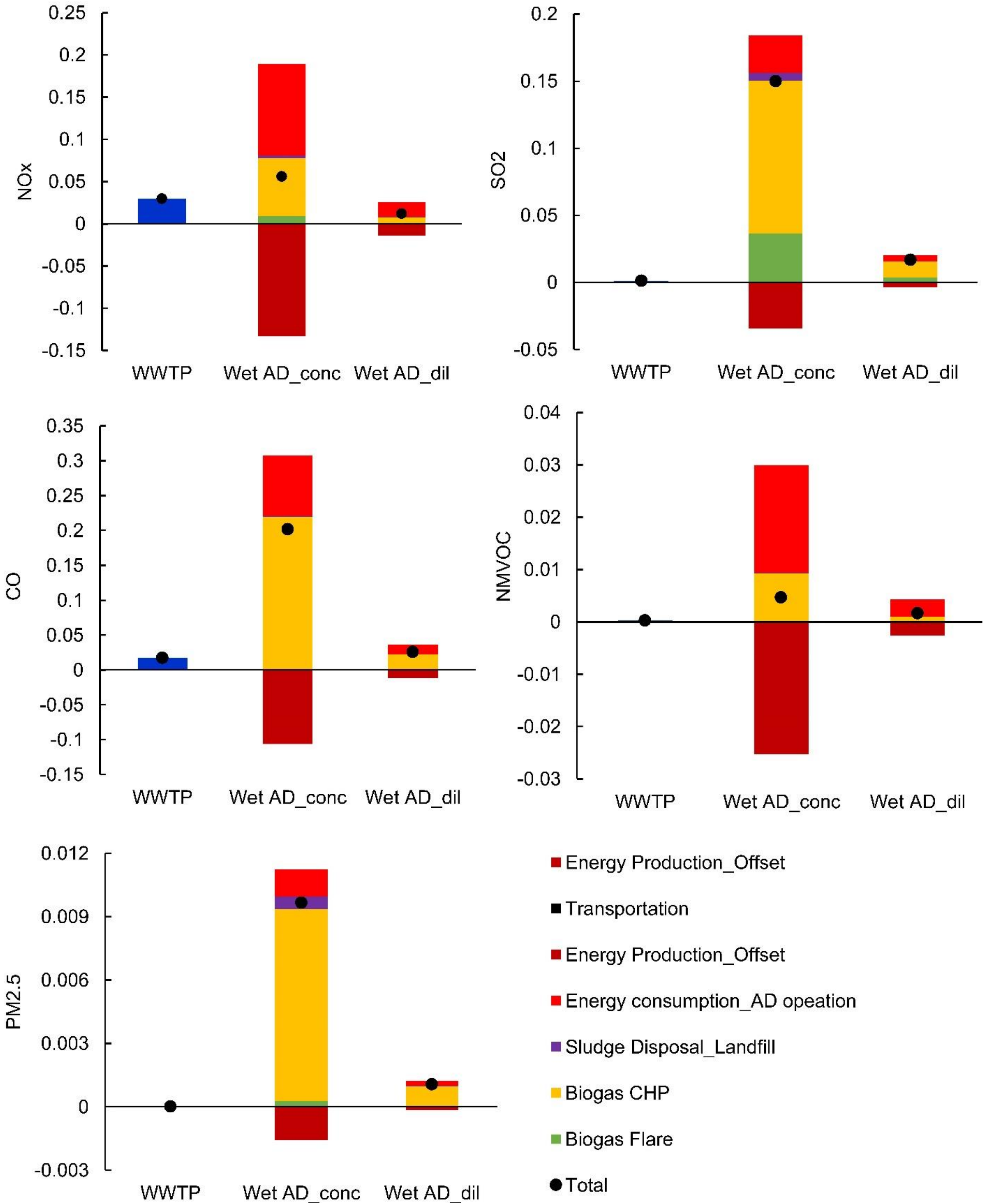
6.4.1.4 Lifecycle Assessment Results – Other Air Pollutants

Unlike CO_2eq, on a relative scale, lifecycle NO_x, $PM_{2.5}$, NMVOC, SO_2 and CO emissions from beverage waste to energy using anaerobic digestion are significantly higher (Figure 58) than WWTP and diluted waste stream scenario. This is because of higher operational energy, especially to operate air compressor units for concentrated waste. However, on an absolute scale, beverage waste to energy technology treating concentrated waste stream emitted 0.056 kg NO_x, 0.15 kg SO_2, 0.20 kg CO, 0.005 kg NMVOC and 0.01 kg $PM_{2.5}$ per gallon of beverage waste received (Figure 58).

Incomplete combustion of biogas in the CHP unit caused CO emissions (Figure 58). CO from electricity generation and consumption is also due to the incomplete combustion of natural gas inside internal combustion engine. This result suggests that avoiding/ minimizing biogas combustion can avoid/ minimize CO emissions. NMVOC from electricity is due to the natural production as well as distribution included in the upstream process. Unlike expected, combustion of biogas in gas engine for power generation (CHP) was also reported to emit NMVOC which was due to solvents used in the CHP unit (Klimont et al. 2002; Amous 2018).

Combustion of biogas at CHP unit is the largest contributor to net positive $PM_{2.5}$ emissions. Use of emission reduction technologies such as ceramic filters (for high temperatures > 800° C), absolute fabric/ paper filters (for toxic emissions), electrostatic precipitators (for <400° C), wet scrubbers and mechanical collectors in CHP exhaust can help minimize $PM_{2.5}$ emissions (Van Harmelen et al. 2002).

Figure 58: Lifecycle NO_x, $PM_{2.5}$, SO_2, NMVOC and CO per Gallon of Beverage Waste from Various Beverage Waste Management Strategies



Source: Lawrence Berkeley National Laboratory

Just considering NO_x emissions, wet AD of the diluted waste stream would result in the lowest lifecycle NO_x emissions. This is largely due to the fact that there is less anaerobic digestate solid byproduct that needs to be sent to a landfill, lowering NO_x emissions from flaring of landfill gas. On the other hand, sending the beverage waste to an existing wastewater treatment facility has lower $PM_{2.5}$, NMVOC, SO_2 and CO emissions than the two energy generation strategies discussed in this case study. Electricity and landfill are notable contributors to NO_x emissions, while CHP and electricity (NGCC) are significant contributors to $PM_{2.5}$, NMVOC, SO_2 and CO emissions. In this preliminary analysis, sending beverage waste to an existing wastewater treatment facility without power generation has the lowest non-GHG emissions assuming conventional air pollution control technologies. However, the emissions from onsite treatment are relatively small, and the environmental benefits of lower GHG emissions is achieved.

CHAPTER 7: Project Impacts and Conclusions

7.1 Results Summary

The analysis indicates there is ample potential for new district energy networks (DEN) to be built and powered by bioenergy in multiple climate zones within California, yielding offsets in fossil fuel consumption and net negative greenhouse gas emissions. Growth in new floorspace of key building types such as residential, retail, office, and hotels can support the development of large mixed-use developments, which are ideal candidates for new DEN. While there is some modest potential for the expansion of existing networks based on building floorspace growth, these opportunities are challenging to characterize due to limited data on operating conditions and the parameters in which decisions may be made to add new buildings to an existing network.

The tools developed in this project are capable of quantifying biopower, biogas, and biomethane generation for a broad range of waste-to-energy deployment scenarios at the state and local scales. While the waste conversion model quantifies the amount of biomethane, biogas, and syngas that is economically feasible at various price points, the district energy cost model assesses the economics of DEN and associated energy generation and supply assets using these energy products to generate and sell energy in the form of electricity, heat, and cooling.

The biomass residue inventory conducted in Task 2 suggests that the production of non-forestry waste organics in California could grow 16 percent by 2050 to 71 million tonnes of dry-matter per year; however, growth varies among the waste types generated by the agricultural, industrial, and municipal sectors. With co-processing of diverse high-moisture residue sources and storage of seasonally available low-moisture residues, an adequate steady supply of feedstock to projects is possible in many areas of the state. In addition to their documentation in this report, the detailed methods and results on the project's biomass residue resource inventory and projections are available in a recently published journal article (Breunig et al. 2018). While a number of data sources are specific to California, the methods used to characterize biomass residue production are largely generalizable and provide a useful guide for other states seeking to evaluate their biomass residue resource. Additionally, a scoping analysis on food waste supply and energy potential was carried out for this project, and is available in a recently published journal article (Breunig et al. 2017). Without considering costs, results suggest that at least 66 percent of gross high moisture food waste solids and 23 percent of gross low moisture food waste solids can be treated in-county using existing excess capacity at anaerobic digestion and solid fuel combustion facilities. Roughly 99 percent of high moisture food waste solids and 55 percent of low moisture food waste solids can be processed using existing infrastructure if waste can be shipped anywhere within the state. An important outcome of this scoping analysis was the discovery that biogas flaring practices at existing AD facilities can reduce potential energy production from food waste by 10 to 40 percent. Beyond this analysis, solid fuel combustion facilities are not included in the 2020 and 2050 technoeconomic analysis and lifecycle assessment.

Results stemming from the thermal energy consumption inventory analysis include: geospatial data that gives snapshots of possible future urban forms, thermal energy consumption based on historical land and building activities recorded in Tax Assessor data, and trends in building retrofits and electrification. In a base case scenario of building stock turnover, active residential floorspace increases 16 percent statewide, while active industrial floorspace increases by 16 percent, active commercial floorspace by 40 percent, miscellaneous by 65 percent, and warehouses by 35 percent by 2050. The building stock turnover model developed is robust, because it builds in numerous variables that can be adjusted for alternative assumptions regarding land development patterns, building codes, and climate change. For example, altering the default cap on size increases for rebuilds of demolished buildings can help bound the complexity of densification trends. Additional details are published in a recent journal article (Breunig et al. 2018). This analysis demonstrates the importance of clean energy solutions for meeting building thermal consumption, as climate change, population growth, the emergence of unique building types with high thermal consumption such as IT data centers, and -- most importantly -- slow building retrofitting, may result in continued high natural gas consumption in buildings.

The goal of the biositing tool is to provide the ability for rapid evaluation of potential waste-to-energy sites, including retrofits/expansions of existing facilities or entirely new construction, on the basis of resource availability and potential for waste heat utilization. This requires high-level data for users who wish to survey the whole state for resource-rich regions of interest, as well as very refined data for users who have one or more specific sites in mind and plan to reach out to specific haulers or organic residue-producing locations or entities. Hosted at biositing.jbei/California, this tool also provides the project team with a means of clearly and easily sharing results.

Project results from the integration of the biomass inventory and distributed generation build-out scenarios suggest stand-alone wet and dry AD and dairy digesters are only economical in the year 2020 at average electricity prices of 12 cents/kWh or above due to the need to offset digester capital costs. The research also suggests that wet AD has limited feasibility even at relatively high electricity prices, with a potential to process 1.8 million wet tons per year (TPY) to generate 65 MW of electricity at 20 cents/kWh. Dry AD's potential was found to be much higher, primarily due to the wider range of waste streams dry facilities are able to accept. At an electricity price of 20 cents/kWh, 7 million TPY of dry AD could be economically processed, generating 250 MW. Only 5 percent of dairy manure (1.4 million TPY) could be economically processed, even at 20 cents/kWh, if dairies are not willing to take co-digestion tonnages above 25 percent of their manure tonnage. Stand-alone wet and dry AD facilities fare much better in 2050, and are a significant contributor to bioenergy generation starting at a minimum electricity price of 14 cents/kWh. At the highest modeled electricity price, these facilities are processing almost all of the MSW and food processing resources that they are able to; however, they are still not able to afford to pay for all agricultural residues. While dairy digester feasibility is shown to be significantly higher 2050, these facilities would still only process 14 percent of the state's dairy manure. Wastewater treatment plant co-digestion is estimated to be economically feasible in 2020 at all electricity price points modeled, as waste tipping fees are high enough to offset the co-digestion handling costs even at low energy values. This is especially apparent in the 4 cents/kWh scenario, where the ratio of tonnage processed to electricity produced, is significantly higher than the other scenarios; here the plants are choosing to accept wastes with higher water content and lower energy production value as they are less concerned with electricity revenue. As electricity prices go up, the marginal returns in terms of waste handling and energy generation decrease. At 20 cents/kWh, WWTP process almost 3 million TPY. In 2050, WWTP digestion does not change significantly, due to the fact that the available large treatment facilities are already being utilized in the 2020 scenario. Even at higher gas yield and tipping fee assumptions, the WWTP-only scenario leaves over 60 percent of municipal food wastes unprocessed. Interestingly, FOG waste is not widely accepted at WWTP or other facilities, even though this is typically considered a high-value waste stream due to its high biogas production per solids tonnage. However, FOG tipping fees are assumed to be relatively lower than other municipal waste streams, based on known WWTP fee structures. The team also assumes a low solids content (3 percent) for FOG wastes, which makes its energy production per wet ton less competitive with other waste streams.

Lastly, gasification facilities have extremely high potential relative to the other types of bioenergy facilities, primarily due to their relatively low capital costs. In 2020, at 12 cents/kWh and below, the model results show very high fractions of statewide technically available low-moisture municipal (70-97 percent) and processor (30-74 percent) wastes being economically gasified with the help of their high tipping fees. At 16-20 cents/kWh, essentially all dry MSW and 80 percent of processor LMS would be economically gasified, along with significant amounts of both field residue and orchard and vineyard (OV) residues. This is the only situation in 2020 in which facilities are willing to pay for feedstocks and is likely only possible due to the significant tipping fees being collected simultaneously from other waste streams. OV residues are more valuable than crop residues, due to the higher syngas generation assumed (approximately 4,000 kWh per bone-dry tonne (BDT) for woody wastes compared to 1850 kWh/BDT for grassier residues), while field residues beat out crop residues due to their much lower moisture content (14 percent vs. 40 percent assumed). Electricity production from gasification increases rapidly by 2020, due to the very syngas-inefficient engines being replaced by fuel cells with high electrical efficiency. This makes gasification even more profitable than it already was in the 2020 scenario; however, total tonnage handled only increases relative to 2020 by about 30 percent. This is partially because of the assumed maximum facility size of 400,000 wet tons per year and the fact that the model does not allow for building multiple facilities at a given site; at electricity prices of 14 cents/kWh and above, most potential sites are occupied by a facility.

When the model allowed different types of bioenergy facilities to compete in 2020, as shown in the "All Competing" scenario (bottom of Table 47; Table 51), it resulted in gasification facilities taking all technically available low-moisture wastes and in WWTP taking the high-moisture and liquid waste streams. When the model assumes higher price points, a small amount of dairy and wet AD also becomes economical to operate. However, significant portions of the waste stream are still uneconomical to process: about half of technically available MSW food waste, 30 percent of processor HMS, and nearly all FOG, dairy manure, and row crop culls and residues. In the 2050 scenarios, the model showed dry AD taking a significant amount of MSW food waste, such that only 25 percent is left unprocessed; however, to do so the facility must pay for row crop residues to meet the dry waste fraction requirements, as the valuable dry MSW and processing wastes are sent to more profitable gasification facilities first. Wet wastes, however, are left unprocessed as the profit-maximizing formulation of the model concentrates the highest-value wastes at the cheapest facilities, namely WWTP. WWTP capacity is limited, however, and by the time there is no more room at WWTP, there aren't enough high-value wastes streams close enough together to justify stand-alone wet or dry AD facilities. Future work could be done to assess re-formulation of the model to distribute high-value wastes in such a way to maximize waste processed while still ensuring profitability. However, for this strategy to be implemented in practice, outside intervention through municipal waste contracts, state policies, or both would likely be needed.

As expected, our model results in wet, dry, and WWTP AD facilities that are concentrated in urban areas, where the majority of high-value waste and WWTP infrastructure is located. Dairy facilities are concentrated in the Central Valley, with a couple along the southern border of the state. Gasification facilities cover almost the entirety of the state, as they process both urban and agricultural wastes at the 20 cents/kWh price point. These are the only bioenergy facilities that reach the northernmost parts of the state.

From a lifecycle perspective, the researchers found that the scenarios with the lowest GHG emissions are those that: divert wet organic wastes from landfills and dry organic wastes from open burning; increase electricity generation that offsets natural gas generation; and dispose of biochar and digestate in a manner that avoids additional methane and nitrous oxide emissions and provides enhanced soil organic carbon sequestration. The integration of anaerobic digestion and gasification into biomass-to-energy strategies on a commercial scale can yield significant environmental benefits and contribute to local climate change mitigation goals. On average, the model showed that electricity production with higher energy price outperformed pipeline scenarios for all air pollutants except SO_2. For this pollutant, the pipeline scenario benefitted from the avoided combustion of biogas and flare, thereby minimizing SO_2 emissions among waste to energy options. The environmental performance of the biomethane production-to-pipeline scenario can be improved by diverting agricultural waste from burning to either gasification or anaerobic digestion. This may be possible if policies can be developed that optimize tipping fees and energy prices in a manner that accounts for the significant benefit of reducing seasonal agricultural burning of wastes. Regardless of bioenergy investments, control measures should be adopted to reduce direct NO_x, PM, and CO emissions from open pile burning of agricultural residues.

While the waste conversion model described above quantifies the amount of biomethane, biogas, and syngas that is economically feasible at various price points, the district energy cost model assesses the economics of district energy networks (DEN), and associated energy generation and supply assets using these energy products, to generate and sell energy in the form of electricity, heat, and cooling.

Of the five systems modeled, the Bay Area site has the lowest thermal energy demands and is therefore generally sized much smaller in terms of CHP capacity, chiller capacity, and electricity sales to the grid, while the Central Valley site is the largest system modeled. Full results for all five climate zone sites are given in Table 58, and some results for the remaining sites are provided in Figure 50: 2050 Costs and Revenues for a Limited Set of New DEN Scenarios in Three California Regions. For each DEN scenario, there is a low, medium, and high fuel cost scenario, according to the fuel price assumptions described above. All systems at all sites have negative net present value (NPV) except for one, meaning the costs of supplying energy to the buildings in the development site are higher than the energy revenues assumed. DEN systems generally cost less than the baseline non-district energy (DE) (N- fossil fuel (FF) and N- renewable electricity (RE)) scenarios at low fuel prices modeled, are similar to the baseline N-FF at medium prices, and slightly higher than all-electric non-district energy (N-RE) scenarios at high fuel prices. In the Bay Area, the research results show that the lowest-cost system is a DEN operating a spark ignited gas engine (SIGE) on direct syngas at low prices, while at all other locations the Fuel Cell is more cost effective.

For DEN scenarios, the labor cost savings are significant, but they are offset by the cost to install and maintain the network piping system. Heating and cooling sales are equal in each energy scenario for a given site, as are electricity sales for all CHP scenarios for a given site and generator type, as these values are defined by the DEN site. For DEN with SIGE generators, outcomes are nearly identical regardless of fuel type. This is because the much lower efficiency of syngas combustion is offset by the relatively lower syngas prices modeled due to the abundant syngas generation found to be possible at these lower prices in the waste conversion model.

In the fuel cell cases where energy efficiency is the same across fuels, lower syngas prices make these systems more attractive than the SIGE case. Milder climates are better-suited to fuel cell applications due to the lower CHP and absorption chiller capacities and fuel consumption required to meet cooling demands.

Clear emissions reductions are associated with CHP for both SIGE and fuel cell systems, in the five climate zones evaluated (Figure 1).

7.2 Research Contributions

The project successfully developed and demonstrated a number of innovative modeling capabilities, including: (1) a building stock turnover model for projecting changes in building floorspace and thermal energy end use at the Tax Assessor land-parcel level; (2) a web-based biositing tool for evaluating the waste biomass resource and energy generation infrastructure at any location in California; (3) a waste conversion facility siting model for locating and sizing wet anaerobic digestion, dry anaerobic digestion, dairy digesters, and gasification waste-to-energy projects for a given energy price point; and (4) a coupled techno-economic and lifecycle analysis framework for evaluating economic and environmental impacts of different pathways that can process large datasets on highly heterogeneous waste organics and perform Monte-Carlo Simulations.

The project has resulted in three technical journal articles to date, as well as a preliminary analysis of waste-to-energy for PepsiCo. The journal articles are as follows:

- Breunig, H. M., Amirebrahimi, J., Smith, S., & Scown, C. D. (2019). Role of Digestate and Biochar in Carbon-Negative Bioenergy. *Environmental Science & Technology*, *53*(22), 12989-12998.
- Breunig, H. M., Huntington, T., Jin, L., Robinson, A., & Scown, C. D. (2018). Temporal and geographic drivers of biomass residues in California. *Resources, Conservation and Recycling*, *139*, 287-297.
- Breunig, H. M., Huntington, T., Jin, L., Robinson, A., & Scown, C. D. (2018). Dynamic Geospatial Modeling of the Building Stock To Project Urban Energy Demand. *Environmental science & technology*, *52*(14), 7604-7613.

7.3 Ratepayer Benefits

This project provides valuable insights for policy makers, utilities, and private companies, to help them identify where California's greatest opportunities lie for cost-competitive and sustainable use of waste biomass for DG. The incorporation of waste heat for cooling may have substantial long-term benefits for the grid in areas where waste biomass aligns with large summer peak demand for air conditioning. This study also will account for expected long- and short-term variations in waste biomass availability, as well as the potential for fuel switching, to ensure sufficient power supply and consistent costs. By matching waste biomass resources with conversion and generation technologies and utility, industrial, commercial, and residential needs, it will help policy makers, utilities, and private companies set their priorities for future research, development, and deployment funding. The ultimate result will be a more resilient grid, reduced investments in transmission infrastructure, and reduced fossil carbon emissions.

The researchers estimated that integrated use of waste biomass (from municipal wastes, agricultural residues, and food processing wastes) for distributed generation applications in California has the potential to produce about 4.2 terawatt-hours of renewable electricity per year, as well as about 190 million therms of renewable heat energy per year. Based on current utility rates, this DG could avoid energy from other sources worth about $780 million (of which $610 million is for avoided grid electricity and $170 million is for avoided natural gas for heating). This is expected to result in avoided fossil greenhouse gas emissions of about 2.5 million metric tons of carbon dioxide (CO_2)-equivalent per year (of which 1.2 million tons is from avoided grid electricity and 1.3 million tons is from avoided natural gas use for heating). This analysis has: (1) identified high-priority areas within California and feedstock types for further public deployment funding, (2) highlighted promising geographic areas or available technologies to encourage increased investment in waste biomass DG by the private sector, and (3) improved efficiency and reduce environmental burdens by helping to minimize biomass transportation distances and maximize the efficiency of power production and waste heat use.

These ratepayer benefit estimates are based on analysis of the potential for DG to enable an increased amount of available waste biomass to be used economically (Table 59).

Table 59: Calculations and Assumptions for Quantitative Benefits

Base case (adapted from CEC 2008)

	Technical potential in 2020 (bone-dry US tons per year)	dry metric tons per year	HHV (GJ/t dry)	TJ (HHV) per year	biomass-to-electricity conversion efficiency	TJ (electricty) per year	MWh (electricity) per year	
Orchard and vineyard	2199000	1999091	20	39982	0.3	11995	3331818	
Field and seed crop	1976000	1796364	18	32335	0.3	9700	2694545	
Vegetable crop	150000	136364	18	2455	0.3	736	204545	
Food and fiber processing	1356000	1232727	18	22189	0.3	6657	1849091	
Animal manures	4600000	4181818	16.5	69000	0.15	10350	2875000	
MSW biomass	11309250	10281136	16.5	169639	0.3	50892	14136563	
		19627500					25091563	MWh
		19.6	million t				25.1	TWh

DG scenario (for EPIC proposal)

Percent of biomass accesible due to DG: 20%

For electricity: 50%

	Technical potential in 2020 (bone-dry US tons per year)	dry metric tons per year	HHV (GJ/t dry)	TJ (HHV) per year	TJ (HHV) per year	biomass-to-electricity conversion efficiency	TJ (electricty) per year	MWh (electricity) per year	
Orchard and vineyard	439800	399818	20	7996	3998	0.30	1199	333182	
Field and seed crop	395200	359273	18	6467	3233	0.30	970	269455	
Vegetable crop	30000	27273	18	491	245	0.30	74	20455	
Food and fiber processing	271200	246545	18	4438	2219	0.30	666	184909	
Animal manures	920000	836364	16.5	13800	6900	0.15	1035	287500	
MSW biomass	2261850	2056227	16.5	33928	16964	0.30	5089	1413656	
		3925500						2509156	MWh
		3.93	million t					2.5	TWh

For CHP: 50%

	TJ (HHV) per year	biomass-to-electricity conversion efficiency	TJ (electricty) per year	MWh (electricity) per year	biomass-to-heat conversion efficiency	TJ (heat) per year	Therms (heat) per year	
Orchard and vineyard	3998	0.20	800	222121	0.60	2399	22738475	
Field and seed crop	3233	0.20	647	179636	0.60	1940	18389315	
Vegetable crop	245	0.20	49	13636	0.60	147	1395950	
Food and fiber processing	2219	0.20	444	123273	0.60	1331	12619388	
Animal manures	6900	0.10	690	191667	0.60	4140	39241706	
MSW biomass	16964	0.20	3393	942438	0.60	10178	96477014	
				1672771	MWh		190861848	Therms
				1.7	TWh			

Source: Lawrence Berkeley National Laboratory

7.4 Knowledge Transfer Activities and Feedback

7.4.1 Technical Advisory Committee Meetings

Throughout this project, the research team used the TAC members as a resource and potential set of users for the results. Features have been added based on their input that improved the results to best reflect the state of waste-to-energy, as well as distributed generation and district energy systems. For the first two years of the project, two separate sets of TAC meetings were conducted because of the distinct subject matter in the tasks that were being conducted. For the remainder of the project, is the researchers oversaw a combined TAC that discussed the full project scope. The TAC members in the latter half of the project were selected from the initial pool of experts with a few new additions. The full list of TAC members is as follows: Todd Pray (Advanced Biofuels and Bioprocess Demonstration Unit), Blake Simmons (LBNL), Sarah Pittiglio (Air Resources Board), Greg Kester (California Association of Sanitation Agencies), Steve Sherman (EBMUD), Nancy Carr (CalRecycle), Evan Johnson (CalRecycle), Pernille Overbye (Ramboll), Michael King (Carbon Trust), Laxmi Rao (IDEA), Doug Nordham (Arup), Richard Damecour (FVB), Henry Johnstone (GLHN Architects and Engineers), Michael Ahern (Ever-Green Energy), Julia Levin (Bioenergy Association of California), Prab Sethi (CEC).

7.4.2 Expert Outreach

Research leaders in the field were reached through a combination of one-on-one meetings and attendance at key conferences. Team members have given talks at the ISSST conference in Buffalo, NY and the Society of Environmental Toxicology and Chemistry (SETAC) conference in Minneapolis, MN. The team is actively collaborating with Callie Babbit's group at RIT, which is working on food waste resource assessments and used in the context of New York State. The team has also collaborated with Steve Kaffka and Rob Williams at UC Davis to assist with data preparation and visualization for the CalBrES summit held in January 2019. To introduce fellow leaders at other national labs to the datasets and tools, the research team held a demonstration for the National Renewable Energy Laboratory (NREL), Oak Ridge National Laboratory (ORNL), and Pacific Northwest National Laboratory (PNNL) researchers working on waste-to-energy.

7.4.3 Industry and Utility Outreach

The team conducted outreach with private companies and regulated utilities to communicate the results and gather feedback. Specific activities included:

- Invited talk at the Bioenergy Association of California quarterly meeting in Oakland, CA
- Meeting with EBMUD staff and tour and discussion with John Hake regarding the operations of EBMUD's food waste digestion program and the feasibility of expanding such programs elsewhere in the State
- Attendance at the wet and gaseous waste-to-energy and products workshop hosted by U.S. DOE program manager Mark Philbrick in Berkeley, CA
- Attendance at Second Meeting of Wastewater and Solid Waste Sectors in Sacramento, CA
- Collaboration and eventual separate U.S. DOE-funded project with Anaergia on the GHG footprint of one of its California-based facilities (Rialto) that co-digests food waste
- Travel to UC Davis and Kearney agricultural research extensions to discuss farming practices and the practicality of collecting different types of crop residue and culled produce. This discussion was with Jeffrey Dahlberg.

7.4.4 Web-Based Tool for Public Use

The web-based biositing tool now resides at https://biositing.jbei.org/california.

This tool provides both detailed resource assessments and thermal energy demand at a fine geospatial resolution. The team provided the link for the tool to numerous collaborators, industry experts, and leaders at the California Energy Commission and ARB to gain feedback on features that would make the tool maximally useful. This tool was used in the first session of the CalBrES summit to frame discussions around the potential for a bioeconomy in California.

7.5 Recommended Future Work

A number of method challenges and data gaps and limitations are identified in this project that could serve as the basis for future work:

- The extensive analysis and data required to model scenarios of waste biomass supply remains a challenge, as does a detailed understand of the local costs of waste biomass collection, transportation, use, and regulations driving current waste management and recycling decisions.
- The team completed a waste biomass resource assessment and thermal energy assessment and used it to construct projections out to 2020 and 2050 from a 2014 base year. While all biomass is plant derived, the physical and chemical properties of biomass vary significantly between and within agricultural and municipal sources. In this study, moisture content and reported efficiency of energy conversion were used to guide the matching of biomass types with conversion technologies. While a number of properties affect the performance and suitability of feedstock blending and conversion, too little data exists to restrict matching further, given the forward looking nature of this analysis. Additional research and development exploring the suitability of specific feedstocks for different energy generation technologies will be valuable.
- To date, there remains a lack of data on the factors leading to decision-making regarding waste biomass residue management and on the cost of waste processing and collection. Surveys to capture the feasibility and costs associated with collecting and delivering different organic residues that are not currently used for energy generation will enable improved planning.
- Detailed inventories of buildings and their energy patterns are either unavailable or costly to obtain in the US. This data gap has resulted in an over reliance on national building surveys and utility aggregated data for baseline estimates of floorspace and energy consumption at smaller spatial resolutions like climate zone or city. Uncertainty resulting from limited building floorspace and energy data has been noted as a challenge in a number of analyses that have sought to determine the cost-effectiveness of emerging technologies and policies to reduce energy consumption and emissions in current and future urban forms (Wei et al. 2014). Providing cleaned, aggregated parcel-level building data free of charge to researchers would vastly improve building energy estimates for long-term planning purposes.
- Data on building stock in the United States exists at the building-level, because property is subject to real estate taxes, which are calculated based on the assessed value of property. However, the comprehensiveness and quality of building attribute data varies by county. A recent assessment determined that the initial standardization of tax assessor data from all US counties and jurisdictions would take more than $22 million (Abt Associates Inc. and Fairview Industries 2013). That study suggests that researchers either perform need-based data collection (only use data from a few counties) or purchase data from private vendors that clean and standardize parcel data (the most common practice). As found over the course of this project, even data purchased from private vendors requires extensive preprocessing to identify and adjust for county-specific data collection and classification practices (e.g. the use of “Miscellaneous” as a building use type or the absence of floorspace square footage). As a result, the inventories of building floorspace developed in this project cannot necessarily be aligned with the existing floorspace model outputs for every climate zone and building type. They can however, provide extensive data on the distribution and age of 10 billion ft^2 of commercial, residential, and industrial floorspace concentrated in

populous and economically active counties, including San Francisco, Los Angeles, San Diego, Sacramento, San Mateo, Fresno, and Alameda Counties. Standardized, cleaned datasets made publicly available for the building stock in California (and nationally) would save time and resources in future research and planning efforts.

- Gasification plays a prominent role in this analysis and is assumed to be a technically viable technology option in 2020 and 2050. Although a number of biomass gasification projects have been completed at the demonstration phase, there are several barriers that hinder widespread commercial development of gasification, including tar removal from syngas and dealing with the high moisture and heterogeneous composition of biomass feedstocks. Many sources consider the most significant challenge to be cleaning the syngas to meet the tar concentration requirement of gas engines and other power generation devices (Asadullah 2014, Sanchez and Kammen 2016). Tar is a sticky substance, and it deposits in the gasification reactor and downstream equipment, blocking the flow of syngas and damaging the reactor apparatus. This creates serious problems for continuous gasifier operation and reduces the expected equipment lifetime. Catalytic hot gas cleaning is the best method for removing tar, but catalyst poisoning is an ongoing problem in the development of this technology and should be addressed with further research and development (Asadullah 2014).
- The high moisture content and heterogeneous composition of biomass have posed a challenge to biomass development for decades. In the realm of gasification, process efficiency is significantly reduced for biomass feedstocks of >30 percent moisture content (McKendry 2002). Drying the biomass adds time, cost, and energy consumption to the gasification process. Bulky and fibrous feedstocks can be difficult to grind, and often get stuck in the feeding line to the gasification reactor. Finally, the heterogeneous nature of biomass translates to an inconsistent chemical composition, making it difficult to regulate the syngas composition being fed to the power generation unit. Gas engines, for example, do not typically operate optimally if the input feedstock is wildly variable (Asadullah 2014). Additional research in which different biomass types and blends can be tested in a specific gasification process and evaluated based on technical challenges and energy yields can help reduce this uncertainty.

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APPENDIX A: County List by Agriculture Region

Table A-1: Region County Index

Bay Area	Coastal	Mountain	Southern	Valley
Alameda	Del Norte	Alpine	Imperial	Butte
Contra Costa	Humboldt	Amador	Los Angeles	Colusa
Marin	Lake	Calaveras	Orange	Fresno
Napa	Mendocino	El Dorado	Riverside	Glenn
San Francisco	Monterey	Inyo	San Bernardino	Kern
San Mateo	San Benito	Lassen	San Diego	Kings
Santa Clara	San Luis Obispo	Mariposa	Ventura	Madera
Solano	Santa Barbara	Modoc		Merced
Sonoma	Santa Cruz	Mono		Placer
		Nevada		Sacramento
		Plumas		San Joaquin
		Sierra		Shasta
		Siskiyou		Stanislaus
		Trinity		Sutter
		Tuolumne		Tehama
				Tulare
				Yolo
				Yuba

Source: Lawrence Berkeley National Laboratory

APPENDIX B: Residue Inventory

Tables Available for Download

Additional data and information, including the following tables are accessible at https://biositing.jbei.org/california.

- Table 60: Manure Yields by Livestock Type and weight [manure-as-excreted in lb/day]
- Table 61: Gross Orchard and Vineyard Residues [BDT/y] (2014)
- Table 62: Gross Orchard and Vineyard Culls [BDT/y] (2014)
- Table 63: Gross Row Crop Culls [BDT/y] (2014)
- Table 64: Gross Row Crop Residues [BDT/y] (2014)
- Table 65: Gross Field Residues [BDT/y] (2014)
- Table 66: Cattle Population in 2016 [head]
- Table 67: Population of Poultry, Swine, Goats, Sheep, and Equine in 2012 [head]
- Table 68: Bedding Yields for Poultry
- Table 69: Monthly Manure Production [wet-tonne/month] Based on Example Schedule for 50-Head Fall-Calving Beef Cows and Calf Stock on Rangeland
- Table 70: Gross Livestock Manure for 2012 [BDT/y]
- Table 71: Gross Poultry Bedding (2012) [BDT/y]
- Table 72: Olive and Stone Fruit Pit Production
- Table 73: Gross Processor High Moisture Solids (HMS) [BDT/y] (2014)
- Table 74: Gross Processor Low Moisture Solids (LMS) [BDT/y] (2014)
- Table 75: Gross Disposed Organic MSW [BDT/y] (2014)
- Table 76: Projected Row Crop Culls (2020)
- Table 77: Projected Row Crop Culls (2050)
- Table 78: Projected Row Crop Residue (2020)
- Table 79: Projected Row Crop Residue (2050)
- Table 80: Projected Orchard and Vineyard Residues (2020)
- Table 81: Projected Orchard and Vineyard Residues (2050)
- Table 82: Projected Orchard and Vineyard Culls (2020)
- Table 83: Projected Orchard and Vineyard Culls (2050)
- Table 84: Projected Field and Seed Crop Residues (2020)
- Table 85: Projected Field and Seed Crop Residues (2050)
- Table 86: Projected Supply of Low Moisture Residues from Food and Fiber Processors (2020)

APPENDIX C: Seasonality

Agricultural activities generate waste biomass during different times of the year. Although the exact timing of activities like harvesting, pruning and trimming, and field maintenance varies between years and among farms, the seasonal pattern of activity is well documented for specific crop species in specific agricultural regions. This is possible because of predictable characteristics of plant growth, market demand, and climate. Many crops are annuals, meaning that they complete their growth cycle, from germination to production of seed to death, in one year. Biennials take two years to complete this cycle, while perennials live two or more years.

Deviations from seasonal agricultural patterns can be isolated to a specific year in which crop disease, pests, or severe weather affected farming practices and production yields. Deviations can also span multiple years if they are the result of long droughts, with normal seasonal patterns resuming with adequate rainfall. Long-term changes in climate, soil, and market demand can shift temporal patterns in agricultural activities more permanently. New advances in farming and new technologies can also cause long-term shifts. For example, some crops are now harvested by machine instead of by hand, which leads to a shorter peak production period of produce, and waste biomass. Machine harvesting may also lead to fewer in-situ culls, as produce is collected without discretion in the field and then scrutinized at processing facilities.

In terms of seasonal production in the food processing industry, Amon et al. notes:

"Most of the seasonal residues were disposed using lowest cost options. Fruits and vegetable residue production occurred mostly from July through October in all agricultural production and processing regions of the state. Large carrot and onion companies in the Central Coast and Southern San Joaquin Valley regions can maintain year round processing facilities by trucking produce from farms in Imperial County, California and Yuma, Arizona, which are winter production regions."

Amon et al. notes however that canneries, dehydrators and fresh frozen fruit and vegetable processors mostly operate between May and October and are idle otherwise. Breunig et al. assume 80 percent of residues are allocated to July –Oct and 20 percent to May and June. Fresh and frozen vegetable processors processes crops almost year round, so residue production is set to 80 percent of residues to July-Oct and 20 percent to rest of the year. It is assumed creamery and meat processing operate year round. Fruit dehydrators work two to three months per year drying apricots, plums, raisins, and other fruits. The largest onion dehydrator in the state operates year round with supplies arriving from near and far throughout all potential growing windows. It is assumed that cotton gin waste occurs at same time of cotton harvest, rice hulls occur during harvest of rice, and nut processors operate during nut harvesting.

Long-Term Seasonality Changes

A detailed literature and database review has been conducted in this study for orchards and vineyards, row crops, and field crops (Knutson et al. 1976; Knutson and Miller 1982; University of California Cooperative Extension; National Agricultural Statistics Service 2012; National Agricultural Statistics Service 2015).

Harvesting periods from the 2006 and 1961 USDA NASS California harvesting region-level data are compared for fruit and tree nut crop (Table 94). Harvesting regions included are: Northern Coast, Central Coast, Lake-Mendocino (pears only), Brentwood Contra Costa (apricots only), Solano Contra Costa (pears only), Sacramento River (pears only), Sacramento Valley Sutter (pears only), Sacramento Valley and Foothills (cherries only), San Joaquin Valley, Northern San Joaquin Valley (cherries only), Southern San Joaquin Valley (cherries only), Mountain Areas (apples only), Sierra Mountain (pears only), Southern California, Desert, Coachella Valley (grapefruit only), and Imperial Valley (grapefruit only). Olive and nut harvesting periods have not changed significantly over the last 45 years, however harvesting periods and peak harvesting periods are generally longer for olives and shorter for walnuts. Conversely, avocados, nectarines, plums, and citrus crops have experienced significant changes in harvesting start dates, end dates, and duration.

Harvesting periods and peak harvesting periods start either earlier or remain unchanged in the San Joaquin Valley, with the largest changes seen in nectarine harvesting and peak peach-freestone harvesting that now start ~6 weeks earlier. The exception is apples that now start a month later. Harvesting periods and peak harvesting periods run longer for many crops, with nectarines, plums, oranges, and Valencia oranges having longer periods by a month or more. However, apples and grapes for raisins have shorter total harvesting periods. Peak harvesting periods run longer for nectarines, peaches-freestone, plums, oranges, and Valencia oranges. Exceptions are apples and to a lesser extent walnuts that now have shorter peak harvesting periods.

Harvesting periods and peak harvesting periods also start either earlier or remain unchanged in Southern California, except for avocados which start ~3 weeks later and have a ~6-week shorter harvesting period. Apples and oranges and Valencia oranges have longer peak harvesting periods by roughly a month in Southern California, but lemons have a shorter peak harvesting period by roughly a month. In the Desert, grapefruits are harvested a month earlier and have a longer harvesting period. In the Central Coast, apricots are harvested a month earlier and walnuts have a shorter peak harvesting season by a month. No significant changes were seen in the Sacramento Valley and Foothills, the Northern Coast, the Southern Coast. Not many fruit and nut trees are grown in the mountain areas, however pears are grown in the Sierra Mountain region and are harvested a month later over a shorter time period.

Harvesting periods from the 2009 and 1996 USDA NASS California state-level data are compared for field and seed crops (Table 92, Table 95). The only significant differences between the dataset were a month longer peak harvesting period for rice that runs later in the year and a month longer total harvesting period for hay-alfalfa that runs later in the year. Harvesting periods from the 2009 USDA NASS California state-level data were compared with 1978 harvesting periods for the Central Valley (Sacramento and San Joaquin Valleys), the South Central Coast, and the Desert. Significant differences were found for all regions. Table

96, Table 97, and Table 98 show shift over 31 years for field and seed harvesting and peak harvesting periods. Changes that are 28 days or more are highlighted.

Barley harvesting seasons start earlier and last roughly a month longer in the Central Valley and South Central Coast. Barley harvesting starts at the same time in the Desert, but lasts two months longer.

Oats harvesting seasons start earlier in all regions, and last roughly a month longer in the Central Valley and South Central Coast and roughly four months longer in the Desert. The peak harvesting season starts a month later than it did in 1978 except in the Desert.

Cotton starts later and has a shorter harvesting period by roughly a month in the Central Valley, but starts earlier and has a slightly shorter harvesting period in the Desert. The peak harvesting period shifted a month earlier in the Desert.

Wheat harvesting starts earlier but the harvesting period is roughly the same length in the Central Valley and a month longer for durum wheat in the South Central Coast. The start to the peak wheat harvesting period is earlier in the desert, and the total harvesting period is longer by roughly a month.

Sugarbeet harvesting starts a month later and has a shorter harvesting period by two and half months in the Central Valley. Harvesting in the Desert runs a month longer. A four month shift is seen in sugarbeet harvesting in the South Central Coast as there is a shift from spring to fall planting, however the harvesting period is roughly the same length. The 2010 USDA data reflects fall planting calendar for the entire state, however separate spring planting data was provided in the 1997 USDA report.

Corn for grain and rice harvesting periods did not experience significant changes, although the peak harvesting period for rice is slightly earlier and longer.

Comparable datasets on vegetables and field fruit like berries and melons were not available for as many crops and regions of California, however the USDA NASS report provided comparable data for raspberries and boysenberries. Knutson and Miller report provided data for tomatoes, melons, lettuce, cucumbers, and asparagus, which were compared with more recent harvesting calendars from the UCANR report series (Table 92, Table 99). From these vegetables and field fruits, it was determined that significant changes have occurred in harvesting timing. Asparagus, for example, has a much later harvesting period, and is harvested two months longer in all regions. Other crops like tomatoes, raspberries and boysenberries have earlier harvest start dates and longer harvesting periods. Melons in the Desert are now typically harvested once a year, instead of twice a year, resulting in a much shorter total harvesting period. The harvesting period for cucumbers is the same between 1978 and 2002 in Sacramento Valley, the only region with comparable data.

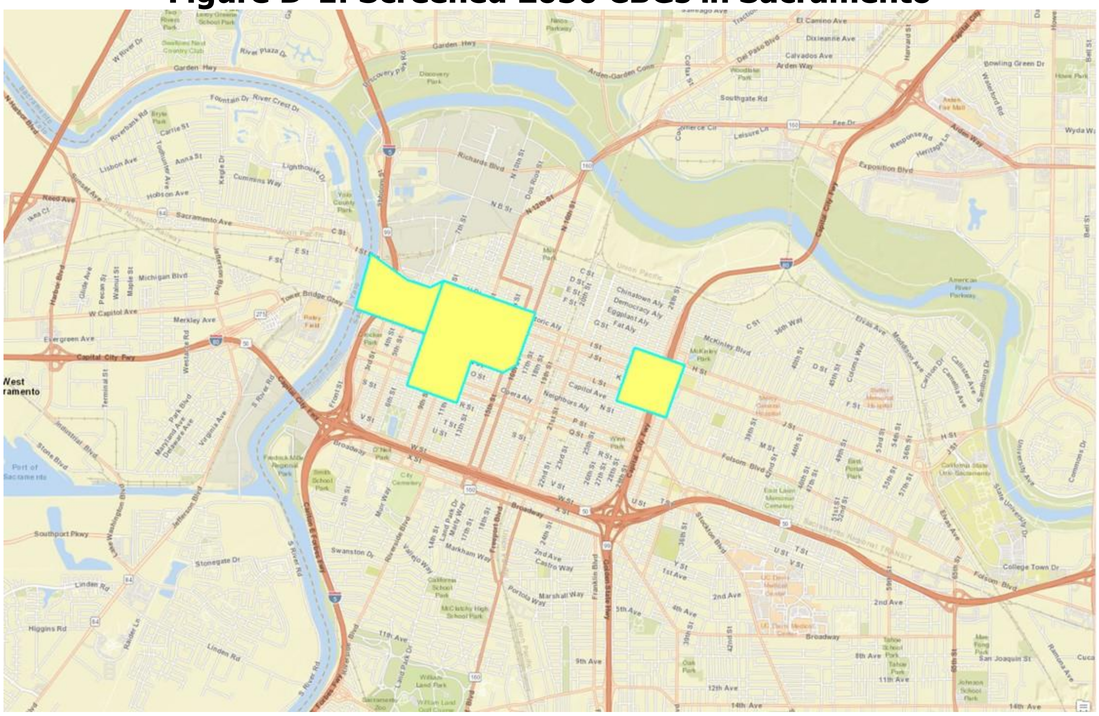
The following tables are available for download in Appendix A. Supplementary data at https://doi.org/10.1016/j.resconrec.2018.08.022

- Table 92: Field and Seed Harvesting Periods
- Table 93: Row Crop Harvesting Periods
- Table 94: Continued Row Crop Harvesting Period

APPENDIX D: Maps of Census Block Groups Relevant to Expansion of Existing Networks Analysis

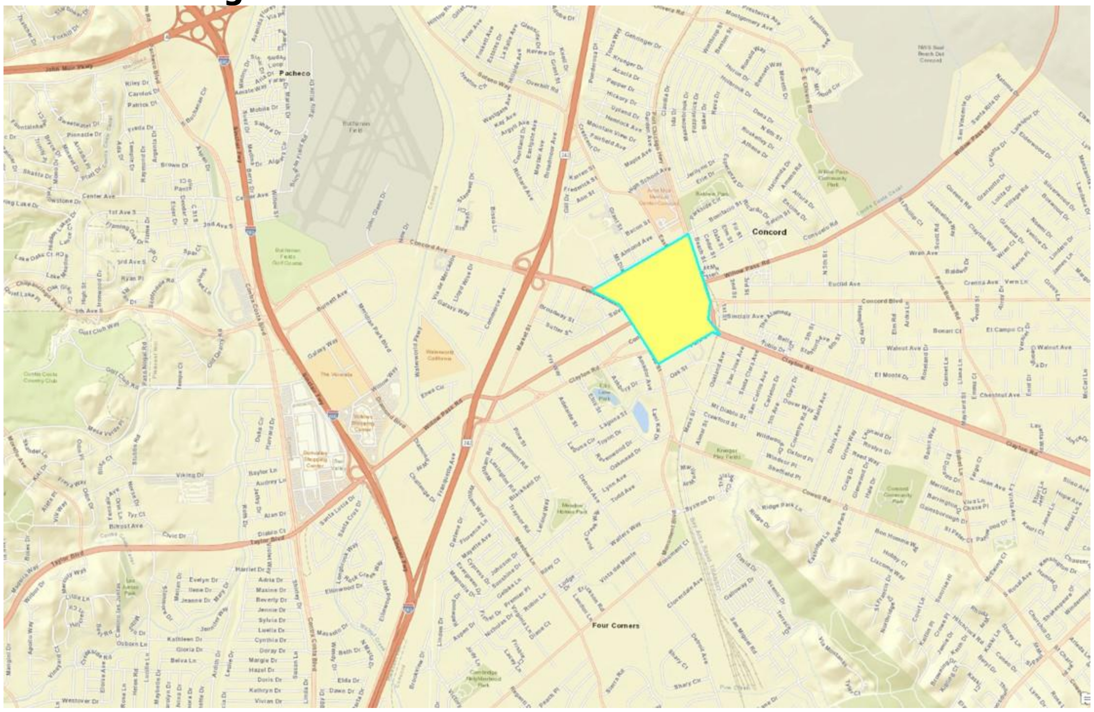
Census block groups that are within two miles of an existing District Energy System, that meet 2.22 kWh- heating /ft^2-CBG area and 5.17 kWh cooling/ft^2-CBG area consumption thresholds and have both heating and cooling diversity scores equal to or greater than 24. These groups are identified based off the 2050 Run 0 dataset from the building stock model (discussed in detail in Chapter 3).

Figure D-1: Screened 2050 CBGs in Sacramento



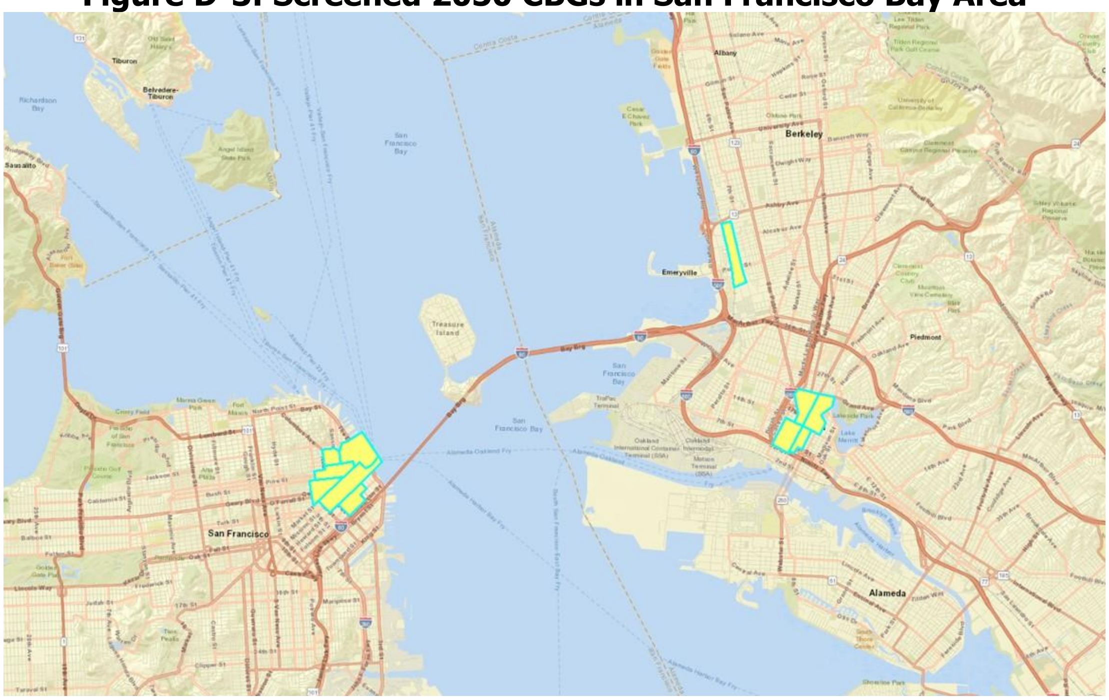
Source: Lawrence Berkeley National Laboratory

Figure D-2: Screened 2050 CBGs in Concord



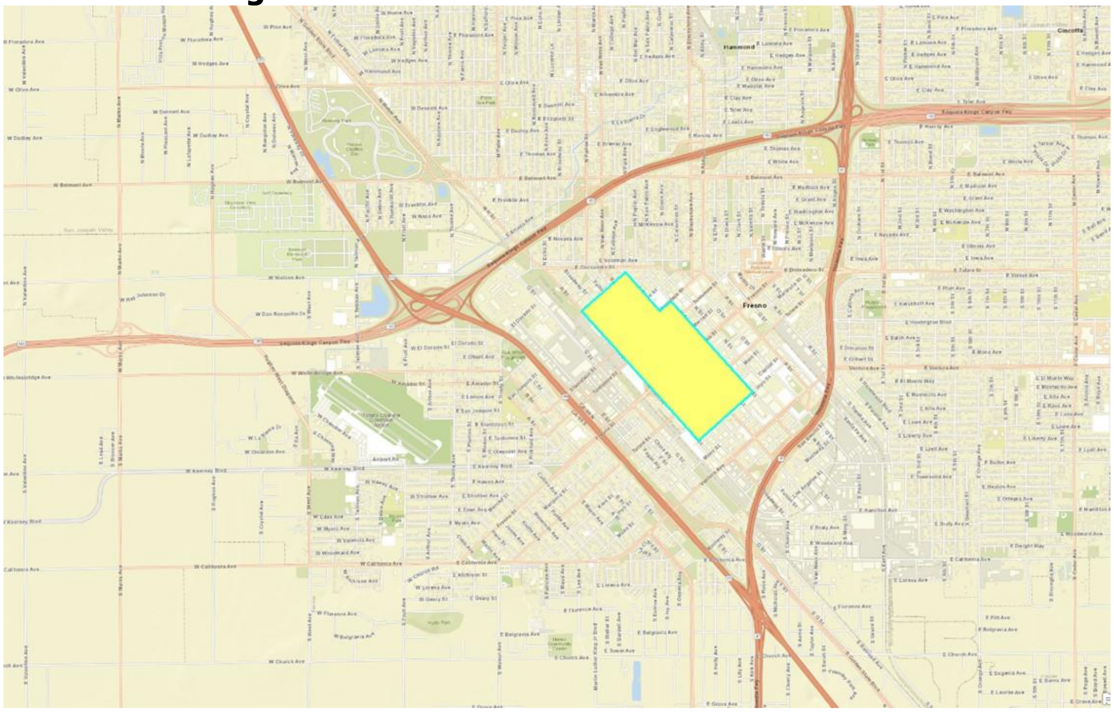
Source: Lawrence Berkeley National Laboratory

Figure D-3: Screened 2050 CBGs in San Francisco Bay Area



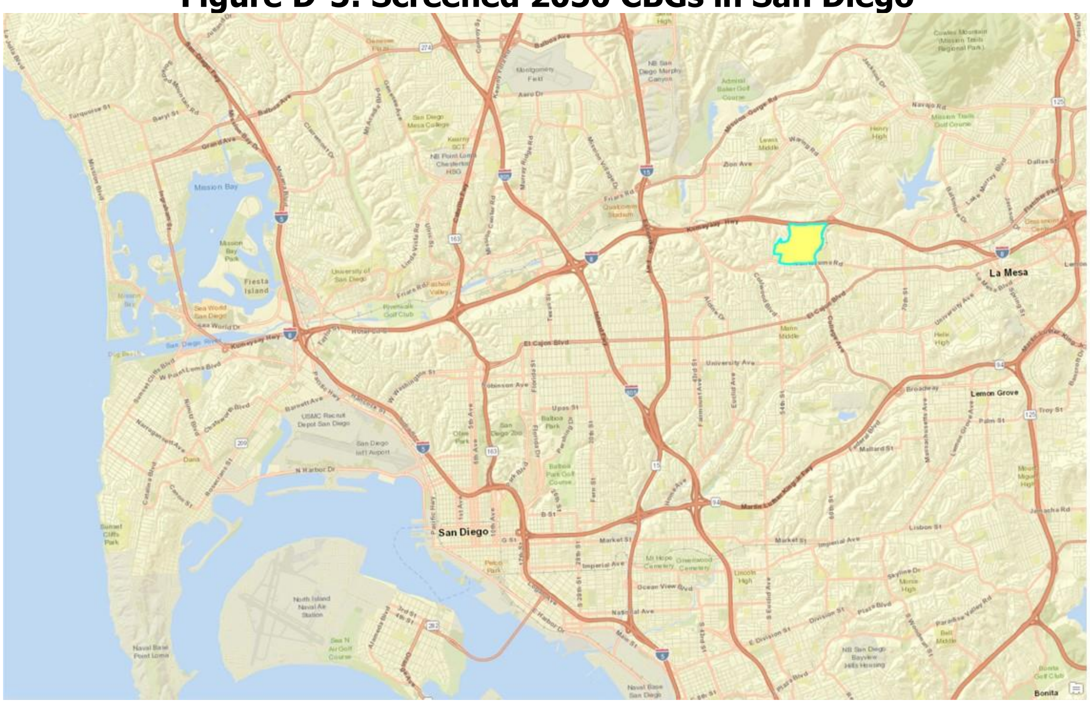
Source: Lawrence Berkeley National Laboratory

Figure D-4: Screened 2050 CBGs in Fresno



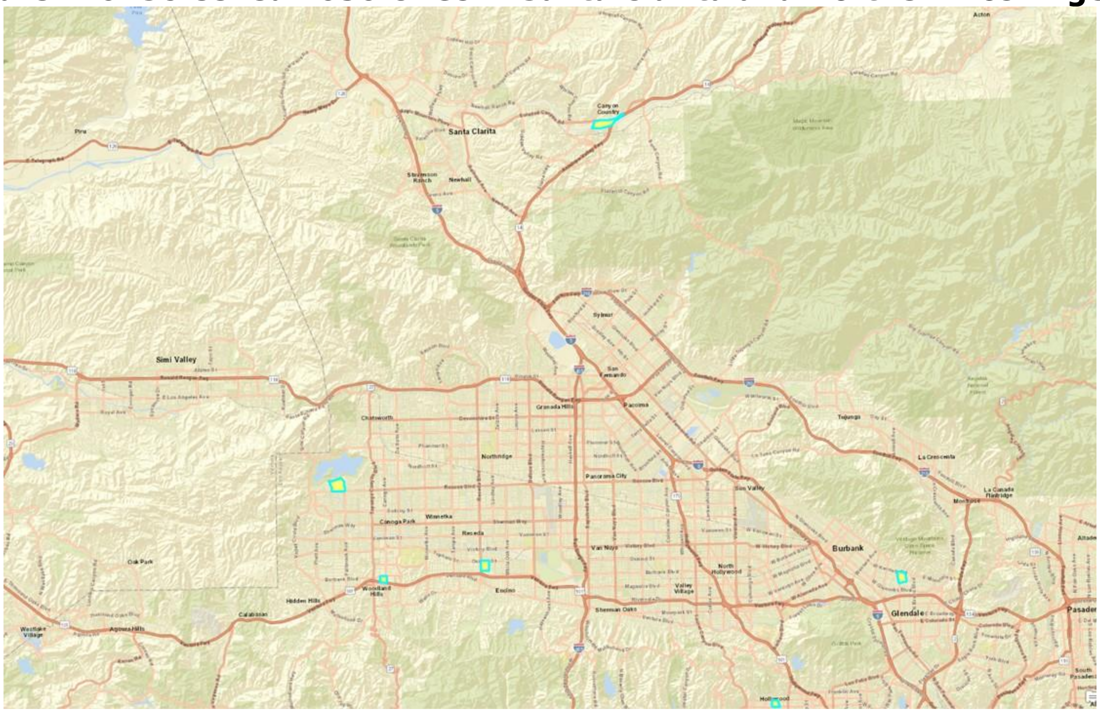
Source: Lawrence Berkeley National Laboratory

Figure D-5: Screened 2050 CBGs in San Diego



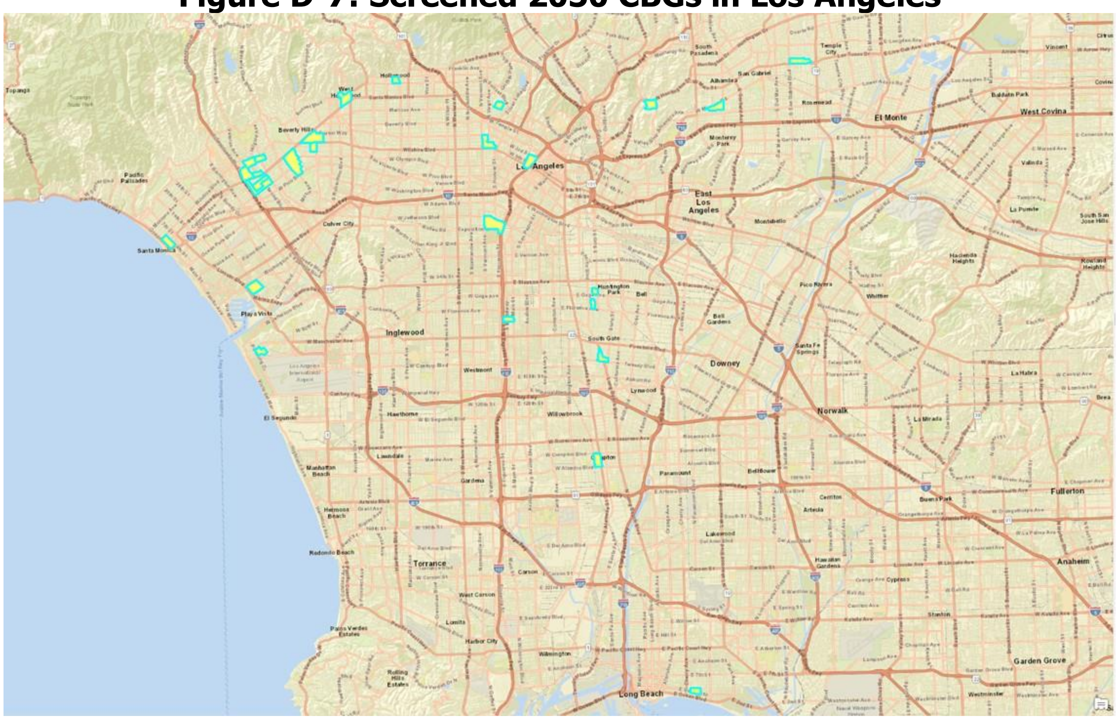
Source: Lawrence Berkeley National Laboratory

Figure D-6: Screened 2050 CBGs in Santa Clarita and Northern Los Angeles



Source: Lawrence Berkeley National Laboratory

Figure D-7: Screened 2050 CBGs in Los Angeles



Source: Lawrence Berkeley National Laboratory

APPENDIX E: Lifecycle Inventory Results

Tables Available for Download

Additional data and information are accessible at https://biositing.jbei.org/california.

The following tables are available for download at the abovementioned link:

Table E-1: Lifecycle Greenhouse Gas Emissions from Various Waste Management Techniques for the Year 2020 (kg CO_{2eq}/tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	4.63E-01	4.26E-01	4.23E-01	2.96E-01	3.93E-01
Diesel	2.68E-01	2.49E-01	2.46E-01	1.83E-01	2.31E-01
Other Electricity	-2.25E+01	-1.30E+01	1.24E-14	3.00E-01	1.34E-01
Natural Gas	-6.76E+00	-6.99E+00	-6.59E+00	-7.99E+00	-6.91E+00
Transportation	-7.15E+00	-5.64E+00	-3.17E+00	-2.22E+01	-9.92E+00
Landfill	-4.19E+00	-3.57E+00	-1.74E+00	-2.79E+00	-1.99E+00
Compost Application	3.66E+01	6.26E+01	1.38E+02	7.48E+01	1.13E+02
Chemicals	-6.56E+01	-7.32E+01	-7.36E+01	-7.31E+01	-7.36E+01
Facility Flare	-1.54E-14	8.45E-16	-2.10E-16	-5.25E-15	-1.76E-15
Organics Composting	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Digestate Application	3.84E+01	4.29E+01	4.31E+01	4.28E+01	4.31E+01
Fertilizer Use	-4.86E+00	-2.32E+00	0.00E+00	-7.51E+00	-1.69E+00
CHP	-1.46E+01	-1.54E+01	-1.47E+01	-1.69E+01	-1.52E+01
Biofilter Release	1.49E+00	9.48E-01	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biochar Application	0.00E+00	0.00E+00	0.00E+00	4.93E+00	1.77E+00
Agricultural Residue Burning	-1.39E+01	-8.68E+00	0.00E+00	0.00E+00	0.00E+00
Electricity Mix	1.34E+01	3.91E+01	3.91E+01	0.00E+00	0.00E+00
Gasification	7.13E+00	4.04E+00	0.00E+00	3.91E+01	3.91E+01
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

Table E-2: Lifecycle CO Emissions from Various Waste Management Techniques for the Year 2020 (kg CO/tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	3.10E-05	2.88E-05	2.85E-05	2.09E-05	2.66E-05
Diesel	1.14E-04	1.06E-04	1.04E-04	7.75E-05	9.78E-05
Other Electricity	-7.70E-03	-4.45E-03	4.25E-18	1.03E-04	4.60E-05
Natural Gas	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transportation	-1.06E-03	-8.33E-04	-4.69E-04	-5.11E-04	-4.77E-04
Landfill	4.32E-04	4.14E-04	3.96E-04	3.87E-04	3.93E-04
Compost Application	3.48E-04	6.38E-04	1.94E-03	1.24E-03	1.69E-03
Chemicals	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Facility Flare	1.08E-27	-2.87E-28	-9.82E-28	-2.16E-28	-1.26E-27
Organics Composting	3.53E-05	2.25E-05	0.00E+00	0.00E+00	0.00E+00
Digestate Application	3.31E-02	3.69E-02	3.71E-02	3.69E-02	3.71E-02
Fertilizer Use	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CHP	5.40E-17	1.06E-18	1.75E-17	-8.53E-17	-3.49E-17
Biofilter Release	1.03E-02	6.54E-03	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biochar Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Agricultural Residue Burning	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Electricity Mix	5.31E-01	1.55E+00	1.55E+00	1.55E+00	1.55E+00
Gasification	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

Table E-3: Lifecycle NO_X Emissions from Various Waste Management Techniques for the Year 2020 (kg NO_X/tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	8.89E-05	8.24E-05	8.16E-05	5.97E-05	7.62E-05
Diesel	2.09E-04	1.94E-04	1.92E-04	1.42E-04	1.80E-04
Other Electricity	-1.77E-02	-1.02E-02	9.75E-18	2.35E-04	1.05E-04
Natural Gas	-4.85E-03	-5.02E-03	-4.73E-03	-5.74E-03	-4.96E-03
Transportation	-3.01E-03	-2.37E-03	-1.34E-03	-1.46E-03	-1.36E-03
Landfill	3.57E-04	2.41E-04	2.29E-04	3.37E-05	1.80E-04
Compost Application	3.91E-04	4.24E-04	5.96E-04	5.13E-04	5.75E-04
Chemicals	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Facility Flare	3.07E-27	-8.19E-28	-2.80E-27	-6.17E-28	-3.60E-27
Organics Composting	4.52E-04	2.88E-04	0.00E+00	0.00E+00	0.00E+00
Digestate Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fertilizer Use	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CHP	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biofilter Release	3.21E-03	2.04E-03	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biochar Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Agricultural Residue Burning	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Electricity Mix	2.53E-02	7.38E-02	7.38E-02	7.38E-02	7.38E-02
Gasification	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

Table E-4: Lifecycle PM2.5 Emissions from Various Waste Management Techniques for the Year 2020 (kg PM2.5 /tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	2.82E-06	2.62E-06	2.59E-06	5.97E-05	2.42E-06
Diesel	2.35E-05	2.19E-05	2.16E-05	1.42E-04	2.03E-05
Other Electricity	-3.68E-04	-2.13E-04	2.03E-19	2.35E-04	2.20E-06
Natural Gas	0.00E+00	0.00E+00	0.00E+00	-5.74E-03	0.00E+00
Transportation	-9.57E-05	-7.54E-05	-4.24E-05	-1.46E-03	-4.32E-05
Landfill	3.47E-05	2.21E-05	2.09E-05	3.37E-05	1.58E-05
Compost Application	1.22E-04	2.24E-04	6.73E-04	5.13E-04	5.85E-04
Chemicals	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Facility Flare	9.72E-29	-2.59E-29	-8.86E-29	-6.17E-28	-1.14E-28
Organics Composting	1.28E-05	8.18E-06	0.00E+00	0.00E+00	0.00E+00
Digestate Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fertilizer Use	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CHP	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biofilter Release	5.21E-05	3.32E-05	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biochar Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Agricultural Residue Burning	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Electricity Mix	1.46E-03	4.28E-03	4.28E-03	7.38E-02	4.28E-03
Gasification	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

Table E-5: Lifecycle SO_2 Emissions from Various Waste Management Techniques for the Year 2020 (kg SO_2/tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	-5.73E-07	-6.16E-07	-5.71E-07	-7.90E-07	-6.22E-07
Diesel	8.13E-04	7.56E-04	7.47E-04	5.55E-04	7.00E-04
Other Electricity	-1.93E-04	-1.12E-04	1.06E-19	2.57E-06	1.15E-06
Natural Gas	-5.37E-03	-5.55E-03	-5.23E-03	-6.35E-03	-5.49E-03
Transportation	-7.56E-06	-5.96E-06	-3.35E-06	-3.65E-06	-3.41E-06
Landfill	3.10E-05	1.87E-05	1.74E-05	-2.10E-06	1.26E-05
Compost Application	1.25E-03	2.29E-03	6.99E-03	4.49E-03	6.09E-03
Chemicals	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Facility Flare	1.24E-24	-3.30E-25	-1.13E-24	-2.49E-25	-1.45E-24
Organics Composting	1.72E-03	1.09E-03	0.00E+00	0.00E+00	0.00E+00
Digestate Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fertilizer Use	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CHP	1.97E-19	3.85E-21	6.37E-20	-3.11E-19	-1.27E-19
Biofilter Release	5.35E-03	3.41E-03	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biochar Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Agricultural Residue Burning	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Electricity Mix	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Gasification	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

Table E-6: Lifecycle VOC Emissions from Various Waste Management Techniques for the Year 2020 (kg VOC /tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Diesel	1.47E-04	1.37E-04	1.35E-04	1.01E-04	1.27E-04
Other Electricity	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Natural Gas	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transportation	-9.73E-03	-7.66E-03	-4.31E-03	-6.38E-03	-4.99E-03
Landfill	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Compost Application	5.47E-06	7.46E-06	2.04E-05	1.57E-05	1.90E-05
Chemicals	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Facility Flare	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Organics Composting	1.17E-05	7.45E-06	0.00E+00	0.00E+00	0.00E+00
Digestate Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fertilizer Use	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CHP	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biofilter Release	4.28E-04	2.73E-04	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biochar Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Agricultural Residue Burning	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Electricity Mix	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Gasification	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

Table E-7: Lifecycle Greenhouse Gas Emissions from Various Waste Management Techniques for the Year 2050 (kg CO_{2eq}/tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	4.63E-01	4.26E-01	4.23E-01	2.96E-01	3.93E-01
Diesel	2.68E-01	2.49E-01	2.46E-01	1.83E-01	2.31E-01
Other Electricity	-6.76E+00	-6.99E+00	-6.59E+00	-7.99E+00	-6.91E+00
Natural Gas	-3.05E+00	-3.26E+00	-3.17E+00	-2.22E+01	-9.94E+00
Transportation	-1.07E+00	-1.76E+00	-1.74E+00	-2.83E+00	-2.01E+00
Landfill	3.66E+01	6.26E+01	1.38E+02	7.48E+01	1.13E+02
Compost Application	-6.56E+01	-7.32E+01	-7.36E+01	-7.31E+01	-7.36E+01
Chemicals	-2.29E-15	-1.66E-15	-2.10E-16	-5.27E-15	-2.13E-15
Facility Flare	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Organics Composting	3.84E+01	4.29E+01	4.31E+01	4.28E+01	4.31E+01
Digestate Application	-4.86E+00	-2.32E+00	0.00E+00	-7.51E+00	-1.69E+00
Fertilizer Use	-1.46E+01	-1.54E+01	-1.47E+01	-1.69E+01	-1.52E+01
CHP	1.49E+00	9.48E-01	0.00E+00	0.00E+00	0.00E+00
Biofilter Release	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	4.93E+00	1.77E+00
Biochar Application	-1.39E+01	-8.68E+00	0.00E+00	0.00E+00	0.00E+00
Agricultural Residue Burning	1.34E+01	3.91E+01	3.91E+01	0.00E+00	0.00E+00
Electricity Mix	-8.42E+00	-4.87E+00	1.24E-14	3.91E+01	3.91E+01
Gasification	7.13E+00	4.04E+00	0.00E+00	1.12E-01	5.03E-02
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

Table E-8: Lifecycle CO Emissions from Various Waste Management Techniques for the Year 2050 (kg CO/tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	3.10E-05	2.88E-05	2.85E-05	2.09E-05	2.66E-05
Diesel	1.14E-04	1.06E-04	1.04E-04	7.75E-05	9.78E-05
Other Electricity	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Natural Gas	-4.51E-04	-4.82E-04	-4.69E-04	-5.19E-04	-4.81E-04
Transportation	4.32E-04	4.14E-04	3.96E-04	3.87E-04	3.93E-04
Landfill	3.48E-04	6.38E-04	1.94E-03	1.24E-03	1.69E-03
Compost Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chemicals	1.19E-27	-1.95E-27	-9.82E-28	-2.72E-28	-1.21E-27
Facility Flare	3.53E-05	2.25E-05	0.00E+00	0.00E+00	0.00E+00
Organics Composting	3.31E-02	3.69E-02	3.71E-02	3.69E-02	3.71E-02
Digestate Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fertilizer Use	-9.26E-18	-8.21E-18	1.75E-17	-5.61E-17	-2.33E-17
CHP	1.03E-02	6.54E-03	0.00E+00	0.00E+00	0.00E+00
Biofilter Release	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biochar Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Agricultural Residue Burning	5.31E-01	1.55E+00	1.55E+00	1.55E+00	1.55E+00
Electricity Mix	-9.27E-03	-5.37E-03	4.25E-18	1.24E-04	5.54E-05
Gasification	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

Table E-9: Lifecycle NO_X Emissions from Various Waste Management Techniques for the Year 2050 (kg NO_X /tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	8.89E-05	8.24E-05	8.16E-05	5.97E-05	7.62E-05
Diesel	2.09E-04	1.94E-04	1.92E-04	1.42E-04	1.80E-04
Other Electricity	-4.85E-03	-5.02E-03	-4.73E-03	-5.74E-03	-4.96E-03
Natural Gas	-1.29E-03	-1.38E-03	-1.34E-03	-1.48E-03	-1.37E-03
Transportation	3.57E-04	2.41E-04	2.29E-04	3.37E-05	1.80E-04
Landfill	3.91E-04	4.24E-04	5.96E-04	5.13E-04	5.75E-04
Compost Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chemicals	3.39E-27	-5.57E-27	-2.80E-27	-7.75E-28	-3.44E-27
Facility Flare	4.52E-04	2.88E-04	0.00E+00	0.00E+00	0.00E+00
Organics Composting	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Digestate Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fertilizer Use	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CHP	3.21E-03	2.04E-03	0.00E+00	0.00E+00	0.00E+00
Biofilter Release	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biochar Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Agricultural Residue Burning	2.53E-02	7.38E-02	7.38E-02	7.38E-02	7.38E-02
Electricity Mix	-1.70E-02	-9.85E-03	9.75E-18	2.27E-04	1.02E-04
Gasification	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

Table E-10: Lifecycle $PM_{2.5}$ Emissions from Various Waste Management Techniques for the Year 2050 (kg $PM_{2.5}$ /tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	2.82E-06	2.62E-06	2.59E-06	1.89E-06	2.42E-06
Diesel	2.35E-05	2.19E-05	2.16E-05	1.61E-05	2.03E-05
Other Electricity	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Natural Gas	-4.09E-05	-4.37E-05	-4.24E-05	-4.69E-05	-4.35E-05
Transportation	3.47E-05	2.21E-05	2.09E-05	4.42E-07	1.58E-05
Landfill	1.22E-04	2.24E-04	6.73E-04	4.30E-04	5.85E-04
Compost Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chemicals	1.07E-28	-1.76E-28	-8.86E-29	-2.45E-29	-1.09E-28
Facility Flare	1.28E-05	8.18E-06	0.00E+00	0.00E+00	0.00E+00
Organics Composting	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Digestate Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fertilizer Use	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CHP	5.21E-05	3.32E-05	0.00E+00	0.00E+00	0.00E+00
Biofilter Release	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biochar Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Agricultural Residue Burning	1.46E-03	4.28E-03	4.28E-03	4.28E-03	4.28E-03
Electricity Mix	-2.28E-04	-1.32E-04	2.03E-19	3.04E-06	1.36E-06
Gasification	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

Table E-11: Lifecycle SO_2 Emissions from Various Waste Management Techniques for the Year 2050 (kg SO_2/tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	-5.73E-07	-6.16E-07	-5.71E-07	-7.90E-07	-6.22E-07
Diesel	8.13E-04	7.56E-04	7.47E-04	5.55E-04	7.00E-04
Other Electricity	-5.37E-03	-5.55E-03	-5.23E-03	-6.35E-03	-5.49E-03
Natural Gas	-3.23E-06	-3.45E-06	-3.35E-06	-3.71E-06	-3.44E-06
Transportation	3.10E-05	1.87E-05	1.74E-05	-2.10E-06	1.26E-05
Landfill	1.25E-03	2.29E-03	6.99E-03	4.49E-03	6.09E-03
Compost Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chemicals	1.37E-24	-2.25E-24	-1.13E-24	-3.12E-25	-1.39E-24
Facility Flare	1.72E-03	1.09E-03	0.00E+00	0.00E+00	0.00E+00
Organics Composting	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Digestate Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fertilizer Use	-3.38E-20	-2.99E-20	6.37E-20	-2.05E-19	-8.49E-20
CHP	5.35E-03	3.41E-03	0.00E+00	0.00E+00	0.00E+00
Biofilter Release	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biochar Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Agricultural Residue Burning	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Electricity Mix	-2.65E-04	-1.53E-04	1.06E-19	3.53E-06	1.58E-06
Gasification	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

Table E-12: Lifecycle VOC Emissions from Various Waste Management Techniques for the Year 2050 (kg VOC /tonne of waste)

Contributor	Electricity/ High	Electricity/ Low	BAU	RNG/High	RNG/Low
Petroleum Products	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Diesel	1.47E-04	1.37E-04	1.35E-04	1.01E-04	1.27E-04
Other Electricity	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Natural Gas	-4.15E-03	-4.44E-03	-4.31E-03	-6.45E-03	-5.02E-03
Transportation	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Landfill	5.47E-06	7.46E-06	2.04E-05	1.57E-05	1.90E-05
Compost Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chemicals	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Facility Flare	1.17E-05	7.45E-06	0.00E+00	0.00E+00	0.00E+00
Organics Composting	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Digestate Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fertilizer Use	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CHP	4.28E-04	2.73E-04	0.00E+00	0.00E+00	0.00E+00
Biofilter Release	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sequestration	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biochar Application	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Agricultural Residue Burning	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Electricity Mix	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Gasification	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Liquid Digestate Treatment	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Source: Lawrence Berkeley National Laboratory

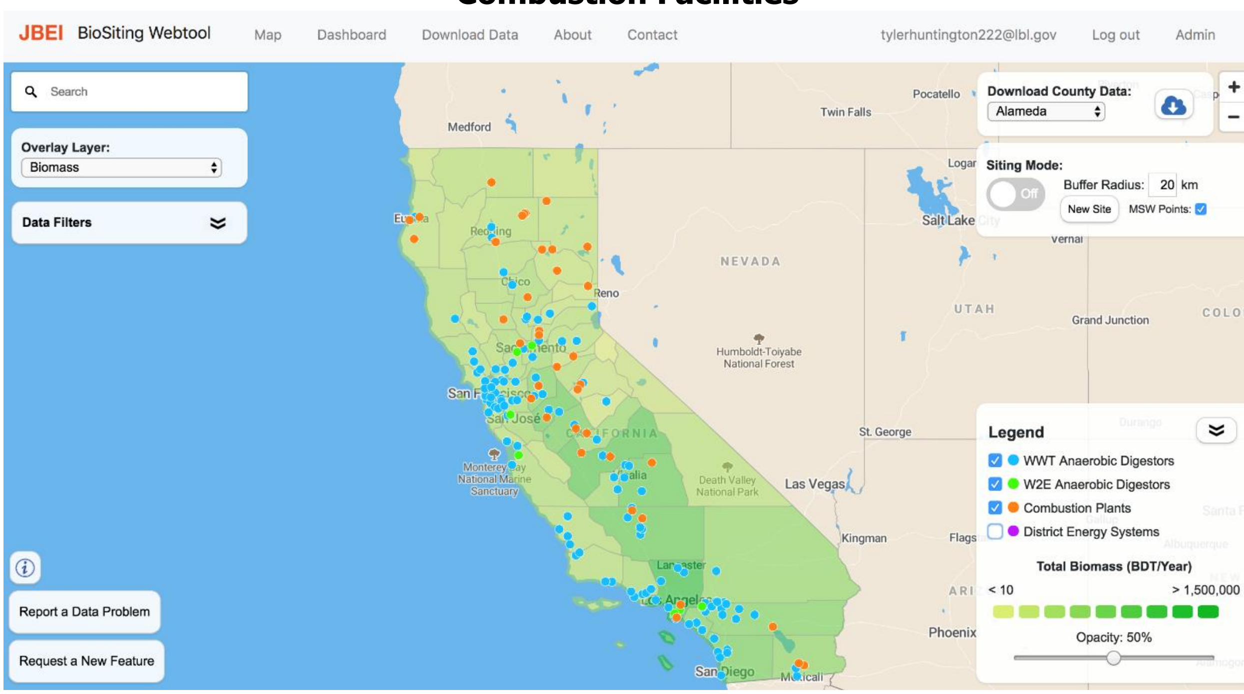
APPENDIX F:
Existing Infrastructure

A number of resources provide lists of existing waste to energy and bioenergy facilities in the state of California. These include:

- https://ucanr.edu/sites/WoodyBiomass/files/212812.pdf
- https://www.energy.ca.gov/biomass/biomass.html
- https://www.energy.ca.gov/almanac/renewables_data/biomass/
- Table 13: Biomass facilities included in the biositing tool as of March 25, 2019

A list of facilities is accessible through the BioSiting Webtool developed for this project; the user can explore these facilities, as reflected in Figure showing the user interface.

Figure F-1: Screenshot of the BioSiting Webtool Showing Existing Wet AD, Stand-Alone Dry AD or Other Waste to Energy (W2E) AD Systems, and Solid Biomass Combustion Facilities



Source: Accessed March 7, 2019. biositing.jbei.org/California