Determining Dry Anaerobic Digestion Feasibility to Advance State Environmental Ambitions

Jahon Amirebrahimi

Lawrence Berkeley National Laboratory,
Electricity Markets and Policy Group[1]

Spring 2019

[1] The author conducted this study as part of the program of professional education at the Goldman School of Public Policy, University of California at Berkeley. This paper is submitted in partial fulfillment of the course requirements for the Master of Public Policy degree. The judgements and conclusions are solely those of the author, and are not necessarily endorsed by the Goldman School of Public Policy, by the University of California or by any other agency.

Executive Summary

Dry anaerobic digestion is an underutilized technology in the United States capable of fulfilling many state environment goals by means of organic waste diversion, renewable energy production, and greenhouse gas mitigation. Contributing to this underutilization is the variety of markets in which dry AD facilities engage. Incoming municipal solid waste streams are highly contaminated, competitive electricity and natural gas prices are lower than facility marginal costs, and coproduct end markets are lacking. However, within many states exist policy supports which may benefit dry AD facilities. Solid waste diversion goals, electricity and thermal feed-in-tariffs, renewable fuel carbon credits, and coproduct certifications could potentially realize facility solvency. I develop a financial model to capture a suite of facility types, state variations, and policy supports to evaluate the most impacting regulation for dry AD facility solvency and future investment. Through net present value, sensitivity, and break even analysis, I find that to overcome excessive facility capital and waste management costs facilities must access compost and fertilizer production infrastructure and end markets as well as receive a higher price for accepting incoming organic waste. As such I recommend state governments and industry to focus on the following:

(1) Reducing facility barriers of entry to produce digestate based fertilizers and composts through capital subsidies or flexible standards

(2) Increasing facility inbound waste revenues through lifecycle greenhouse gas based solid waste allowances

(2) Stimulating waste management efficiency gains and cost reductions through national stewardship vertical integration

Table of Contents

Motivation **6**

The State of Dry Anaerobic Digestion in the United States **8**

The Emergence of Wet and Dry Anaerobic Digestion 8

Dry Anaerobic Digestion Process Overview 9

Figure 1: Simplified Dry Anaerobic Digestion Process Flow 9

Dry Anaerobic Digestion Market Overview **10**

Table 1: Markets Engaging with Dry Anaerobic Digestion Facilities 10

Upstream Municipal Solid Waste 10

Downstream Energy Markets 11

Electricity Markets 11

District Heating 12

Natural Gas Markets 12

Operational Barriers 13

Downstream Digestate Markets 13

Compost 14

Fertilizer 14

Potential Dry Anaerobic Digestion Policies **15**

Table 2: Policies Engaging with Dry Anaerobic Digestion Facilities 16

Solid Waste Diversion 16

Figure 2: States with Mandatory Recycling Laws35 17

Air Quality Requirements 18

Feed-In Tariffs 18

Figure 3: U.S. States and Utilities with Feed-In Tariffs or Similar Programs47 19

Pipeline Interconnection Subsidies 19

Renewable Fuel Credits 20

Organic Certifications 21

Food Safety Standards 22

Methodology **23**

Model Inputs 23

Waste Data 23

Operational Data 23
Financial Data 24
Facility Configurations 24
Electricity 24
District Heating 24
Onsite Compost 25
Fertilizer 25
Compressed Natural Gas Onsite 25
Compressed Natural Gas Off Site 25
State Variation 26
Figure 5: Inbound Waste, Outbound Digestate, and Compost Prices 26
Figure 6: Electricity, CNG Onsite and CNG Off Site Prices 27
Figure 7: Labor, Facility and Site Capital Prices 28
Sensitivity, Elasticity, and Break Even Analyses 29

Results **30**
Baseline Solvency 30
Figure 8: Baseline Net Present Value 31
Single Variate Sensitivity 32
Figure 9: Sensitivity Results for a 90,000 Ton Per Year Facility 33
Inbound Tipping 34
Facility Capital Compensation 34
Electricity Feed-In-Tariff 34
Compost Sales 34
Insolvent Sensitivity Scenarios 34
Sensitivity Responsivity 34
Sensitivity Scenarios 35
Table 3: Mean Elasticity of Net Present Value Per Sensitivity Scenario 35
Facility Configurations 35
Table 4: Mean Elasticity of Net Present Value Per Facility Configuration 35
Figure 9: Price Elasticity of Sensitivity Scenarios for a 90K TPY Facility 36
State Contexts 37
Table 5: Mean Elasticity of Net Present Value Per State 37
Outlying Configurations and States 37
Break Even in Oregon 37
Figure 10: Breakeven Tipping Fee at Two Times Sensitivity in Oregon 40

Discussion **41**
Supporting Secondary Revenue Streams 41
Compensating Waste Management and Construction Costs 41
Incoming Waste Impacts 42

Conclusion **42**
Reducing facility barriers of entry to produce digestate based fertilizers and composts through capital subsidies or flexible standards 43
Increasing facility inbound waste revenues through lifecycle greenhouse gas based solid waste allowances 43
Stimulating waste management efficiency gains and cost reductions through national stewardship vertical integration 43

Appendix A: Method Assumptions **44**
Table 6: Cost and Revenue Streams for Facility Configurations 44

Appendix B: Model Prices **45**
Table 7: Cost and Revenue Prices 45

Appendix C: Operational, Cost, and Economic Calculations **46**
Operational Calculations 46
Masses 46
Biogas and Methane Production 47
Electricity Generation 47
Cost Calculations 48
Capital and Site Costs 48
Labor Costs 50
Operations and Maintenance Costs (Non-Labor) 51
Byproducts and Waste Materials 52
Revenues 53
Economic Calculations 55
Average Annual Cash Flow 55
Net Present Value 55
Internal Rate of Return 56

Appendix D: Internal Rate of Return Results **57**
Figure 11: Baseline Internal Rate of Return Per Facility Configuration 57

References **58**

Motivation

Although dry anaerobic digestion (AD) technology is capable of diverting organic waste streams to produce clean electricity, renewable gas, and value-added coproducts, it has been underutilized in the United States (US). As compared to Europe's 248 active dry AD facilities which have the capacity to divert eight million tons of organic waste per year, the US can only divert one million tons with 24 dry AD facilities.[1,2] However, dry AD serves to complement many emerging state environmental policy objectives. Organic waste diversion reduces landfill methane emissions, clean electricity production contributes to state renewable portfolio standards, renewable gas production follows low carbon fuel standards, and small scale distributed energy production reliably serves localized electricity demand.

Attributing to this deficit in capacity investment is the difficulty for regulators and industry to determine dry AD facility feasibility given both varying facility configurations and state contexts. Given the differences in market conditions and regulation in the upstream solid waste industry as well as downstream electricity, natural gas, and agriculture industries, sensitive price signals - like tipping fee revenues, facility capital costs, and electricity sales - vary considerably state by state. In addition, existing regulatory supports may only benefit certain facility types and certain facility upgrades may be unattainable due excessive investment costs. Understanding how different state market and regulatory conditions impact facility feasibility is critical to future deployment.

The following analysis serves as a tool for policy makers and bioenergy industry stakeholders alike to understand the intricacies of dry AD project economics. My research develops a dry AD facility financial model and conducts net present value (NPV) and internal rate of return (IRR) analyses to investigate the conditions in which dry AD facilities are financially solvent. I then conduct sensitivity analyses on key variables bounded by existing market and policy thresholds. I use the elasticity of selected market distortions to compare facility solvency with varying facility configurations and state contexts. As a marginal state in the analysis, I then conduct breakeven analysis for Oregon to determine the maximum policy support required for facility deployment.

This analysis remains bounded by facility considerations. Although I base my analysis on current market and regulatory conditions, I do not consider the political feasibility of additional policy supports or the upstream or downstream market impacts of facility deployment or upgrades. In addition, as I derive the results from generalized and conservative assumptions, it is likely that actual facility conditions may vary considerably. Still, the basis of the model provides a strong step forward comparing a plethora of policy and facility designs.

This report begins by evaluating the current technology and deployment of dry AD in the United States. It then contextualizes existing dry AD facilities by their upstream markets (e.g. municipal solid waste) and downstream markets (e.g. electricity, fuel, compost, and fertilizer). Following those markets, it describes the surrounding policy supports with which these facilities are likely to engage. It provides my analytical approach describing how variation in facility configurations, market contexts, and policy mechanisms are considered to evaluate facility solvency. It describes the results following my base, sensitivity and breakeven analysis. I then discuss the implications of the results for policy makers and industry.

The State of Dry Anaerobic Digestion in the United States

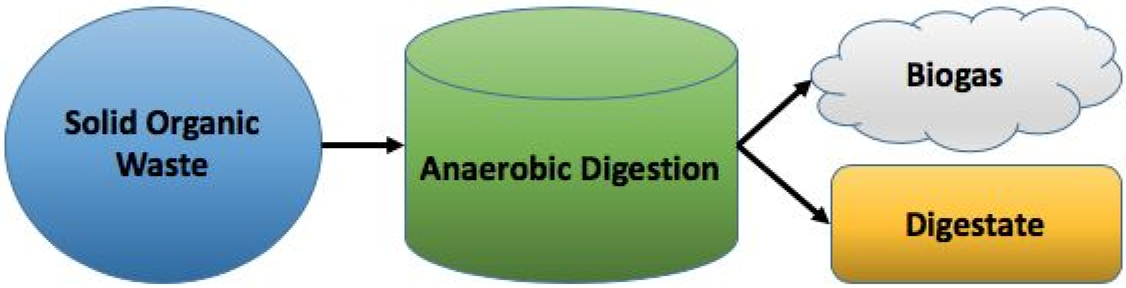
The Emergence of Wet and Dry Anaerobic Digestion

There is uncertainty as to why dry anaerobic digestion (AD) has failed to deploy, reach larger economies of scale, and innovate as opposed to wet AD systems. For well over a century, anaerobic digestion facilities have treated a variety of organic waste streams in the United States (US), capturing methane to produce electricity, renewable fuel, and value-added coproducts. Yet over this century, the rate of deployment between wet and dry AD facilities have greatly differed. Wet AD technology and project feasibility has become well accepted in the US market, as there are currently 175-240 farms and 1484 wastewater treatment plants (WWTPs) utilizing high moisture organic waste streams.[2] These systems are either rural and privately owned or urban and municipally owned, often utilizing a uniform and predictable feedstock of manure or sewage. Of these wet AD facilities, only 10 percent are producing for electricity markets.

In comparison, the market share of dry AD in the United States is much smaller in comparison to that of wet AD. These systems - which utilize low moisture waste streams, like the organic fraction of municipal solid waste (OFMSW), fats, oils and grease (FOG), and certain crop culls and residues - likely face significant challenges deploying and disincentives during scale up efforts. There are 24 active dry AD facilities in the United States accepting approximately a million tons of organic waste per year to produce approximately 17 MW of electricity, 11 MW of thermal energy, 17 million gasoline gallon equivalents of compressed natural gas, 50 thousand short tons of compost, 50 thousand short tons of solid fertilizer, and 14 million gallons of liquid fertilizer.[2] Engaging with a variety of upstream and downstream markets, these facilities may run into both operational uncertainties and regulatory barriers while processing these waste streams.[3]

Dry Anaerobic Digestion Process Overview

Figure 1: Simplified Dry Anaerobic Digestion Process Flow



A key challenge in determining the feasibility of a given dry anaerobic digestion facility is accounting for the variability in feedstock characteristics, processing circumstances, and product quality and market availability. Balances between carbohydrate, lipid, and protein content of the incoming organic waste, the residual content within the incoming organic waste, as well as the carbon and nitrogen ratio of the digesting substrate will influence digester operations and product quality.[4] Digester technologies can vary from batch systems, where the entire digestive process is completed in a single phase without alterations, to continuous systems, where the digestion process can be altered with the addition or removal of feedstock and product. Industry tends to favor simpler systems relative to multi-stage digesters as both the investment costs and the operational knowledge required are lower.[5] Critical to a digester's performance as well is the population dynamics of the microbes used to digest the incoming feedstock influenced by both the incoming feedstock and the reactor temperature.[6] Such variation in these input characteristics and process design, introduce volatility in both production quality and quantity. The outcoming digestate's dry matter, carbon, nitrogen, phosphorus, and potassium content as well as acidity determines whether it is more suitable for land application or compost production.[7] The outcoming biogas's balance between hydrogen, carbon dioxide, methane will determine its suitability for combustion and electricity production or refinement and fuel production.[8,9] There is a tremendous need for policymakers and industry alike to consider this variation in operational circumstances in their decision making.

Dry Anaerobic Digestion Market Overview

Table 1: Markets Engaging with Dry Anaerobic Digestion Facilities

Upstream	Facility	Downstream
Solid Waste Management	Land	Electricity
Agriculture	Anaerobic Digestion	Compressed Natural Gas
Livestock	Combined Heat and Power	District Heating
Landscaping	Biogas Refinement	Compost
	Pipelines	Fertilzer

Upstream Municipal Solid Waste

Despite dry AD's lack of development, there lies great potential for dry AD to utilize existing municipal solid waste streams. In 2015, 52.5 percent of municipal solid waste (138 million tons) was sent to landfill. Of this landfilled waste, 22 percent (or 30 million tons) could have been utilized by dry AD to make significant reductions in the 107.7 MMTCO2e of methane emitted that year.[10,11] This significant underutilization of potential feedstock has largely to do with the existing waste collection and processing infrastructure in the United States.

Beginning in the 1970s, within the solid waste management industry there was a shift from multi-stream collection and drop-off center recycling to single-stream collection by centralized mixed waste processing facilities nationwide. The shift was prompted by innovations in mixed waste processing technology as well as regulatory demand for waste diversion. Haulers streamlined collection of high value secondary materials - like aluminum, dry paper, polyethylene, and high-density polyethylene plastics - by commingling them in a single cart.[12] Rather than being recycled, residential and commercial food waste and green waste (the primary feedstock for dry AD facilties) would often be sent to landfill directly. There had been insufficient end markets and low demand for the organic material, and the marginal cost for processing the material at mixed waste processing facilities were significant. Despite the emergence of dry AD, waste haulers and collectors in many states today do not divert organic waste for value-added processing.

Of the existing dry AD facilities utilizing municipal solid waste streams, they face significant processing costs from separating out inorganic contamination from their feedstock. If a facility is unable to contract directly with producers of a single waste stream (e.g., culls from a farm, or manure from a ranch), they are reliant on the volatile quality of the upstream municipal hauler's mixed waste to fill excess capacity. The resulting uncertainty in preprocessing costs, product quality, and output quantity, introduces greater risk into the facility's solvency.

Downstream Energy Markets

Dry AD facilities have the potential to produce for electricity, thermal, and natural gas markets. In the United States, biogas production could substitute existing natural gas based electricity production by five percent, and retail natural gas distribution by 56 percent.[13] However, in order to tap into this potential, dry AD facilities must consider a variety of factors, principally biogas quality but also transportation costs, wholesale electricity and natural gas price volatility and demand, market competition, as well as upstream and downstream bilateral contract availability and conditions. By producing in place of natural gas refineries and combustion facilities, dry AD facilities are an alternative to fossil fuel energy sources, making considerable reductions to greenhouse gas emissions relatively.

Electricity Markets

Depending on state and regional regulation, dry AD facilities can engage in electricity markets in a number of ways. As small power producers with an average capacity of 0.7 MW per facility,[2] they can bid into wholesale markets or negotiate bilateral contracts with utilities at the avoided cost or feed-in-tariff rate.

The price dry AD facilities receive in wholesale markets are a result of auctions conducted by independent service operators. Competitive bidding between market participants depend on consumer demand each hour as well as producer marginal costs. The resulting price can be an outcome of several factors which include regional market regulation (e.g. cap and trade, renewable portfolio standards), existing market supply (i.e. the mix of existing coal, natural gas, nuclear, hydro, solar or wind electricity in the grid), and market power. As a small power producer, dry AD facilities can engage with their region's independent service operator directly or hire consultants to place their bids on their behalf. The marginal cost of dry anaerobic digesters to produce fuel for electricity production is likely higher than coal generators and natural gas generators with combined cycle combustion units in wholesale markets. In regions with a large supply of low cost electricity on the grid (e.g. wind, solar, hydro, and nuclear) wholesale prices can become disadvantageously low for dry AD facilities.

Federal regulation enables dry AD facilities to access alternate electricity compensation, especially in regions without a wholesale electricity market.[14] As a qualifying facility (QF), they are guaranteed a minimum electricity sale price equivalent to the avoided incremental cost faced by the regional utility to produce identical electricity themselves.[15] However, the mechanism in determining a utilities incremental cost varies state by state. It may be the case that some state pricing mechanisms favor dry AD facilities more or less than others.[16] As described in more detail below, dry AD facilities may also access feed-in tariffs (FiTs), which guarantee them an electricity sale price due to their specific technology. States can either require utilities to offer FiTs, or utilities may voluntarily provide FiTs.

District Heating

In some cases, dry AD facilities can use their CHP units to provide district heating. There are seven active facilities in the United States providing 10.7 MW of thermal energy to nearby buildings.[2] This output is a small fraction of the US market, which contains 660 facilities producing 41 GW[2] of thermal energy by CHP.[17] As providing districting heating services reduces CHP efficiency in producing electricity and may well require pipeline construction and connection to nearby customers, customer revenues must outweigh these associated losses.

Natural Gas Markets

Due to US natural gas market restructuring, dry AD facilities now have a wider variety of delivery options without regulated gas prices. Whereas before such a facility could only contract directly with distribution companies at prices fixed by regulation, now they can serve as independent retailers or transport refined biogas by pipeline to distribution hubs at a variable market price.[18] Of those dry AD facilities producing for natural gas markets, their yearly output is about 2 million gasoline gallon equivalents of compressed natural gas per year,[2] which substitutes relatively little compared to, for example, California refineries which can produce between 48 million to 2 billion gallons of

[2] Estimate assumes an average boiler efficiency of 40%.

gasoline per year - one to three orders of magnitude more.[19] Their influence over the natural gas spot market price is minimal given this limited supply, however when negotiating purchase agreements with regional utilities the wholesale price can serve as a benchmark.

To access this market, dry AD facilities must upgrade their biogas to meet natural gas specifications. The heating value must be close to equivalent, varying by state regulation. Depending on whether the compressed natural gas is sold onsite or offsite determines whether a facility invests in a fueling station or a pipeline to connect to the natural gas grid. Depending on regional spot market regulation and conditions (say, natural gas quality standards), the wholesale price would greatly impact dry AD facility feasibility. Such a price may, as well, not cover the facility's marginal cost.

Operational Barriers

While engaging with upstream and downstream market variability, dry AD facilities can face several operational barriers and fail to maintain regulatory compliance. Dry AD facilities must invest in additional waste processing equipment, as they face high levels of inorganic feedstock contamination in markets which lack contractual, local, and state feedstock quality and delivery requirements. Such contamination also degrades biogas quality, resulting in additional operational and maintenance expenses for their combined heat and power units.[20] To access natural gas markets, dry AD facilities must invest in additional equipment to refine, maintain, store, and transport this degraded biogas - the marginal cost of refinement also fluctuating based on inorganic feedstock contamination. Bilateral contracts or regulated emissions thresholds which do not take into account inconsistent feedstock deliveries and product outputs may frequently be breached, resulting in fines, legal expenditures, and additional investment in emission mitigation equipment.[3]

Downstream Digestate Markets

Digestate - the solid and liquid mass remaining after the digestion process - serves agriculture demand in the form of two products: compost and fertilizer. Dry AD facilities can either compost digestate onsite or truck digestate to nearby compost facilities where the mass undergoes aerobic digestion. After which, compost is generally sold to nearby farms where it can be used as a soil amendment to improve water retention, long term nutrient availability, and organic matter content. Depending on state health regulation, dry AD facilities can skip the compost process and sell digestate directly to end users. The digestate is then utilized as fertilizer and applied directly to the land. As opposed to compost, fertilizers are used by agriculture for short term yield improvements as they are able to provide nitrogen, phosphorus, and potassium immediately to soil and crops. As dry AD facilities decide between biogas and digestate end markets, they must often trade-off between maximizing digestate quality or biogas output, as the processing conditions for each are inversely impacting.[21–23] Although digestate based compost and fertilizer production can substitute petrochemical fertilizer production and provide relative reductions in lifecycle greenhouse gases, the application process, if poorly managed, can release ammonia and organic pollutants as well as contribute to soil metal toxicity.[23–25]

Compost

To produce compost onsite, dry AD facilities must consider technology type, labor requirements, transportation needs, and available end markets for implementation. Ordered by increasing implementation cost and decreasing labor requirements, compost technologies vary between static systems, vermicomposting, turned windrow systems, passively aerated windrow systems, actively aerated systems or bioreactors. Aside from agriculture, compost can be used in horticulture, landscape services, erosion control, soil remediation, green infrastructure development, and carbon sequestration.[26] Quality and consistency are key determinants of the compost's value [27]. In controlled settings, composts produced from digestate can have higher micronutrient concentrations and biological stability than composts produced directly from agroindustrial wastes and manures.[28,29] However, the quality of compost will ultimately be determined by the digestate quality which varies based on the level of inorganic contamination in the feedstock. Of those dry AD facilities generating compost onsite, their output is approximately 12 thousand tons of compost per facility per year.[2]

Fertilizer

Selling the solid or liquid fraction of digestates for land application can substitute existing petrochemical synthetic fertilizers in the US market.[30] Compared to wet AD systems, dry AD systems can yield digestate solids with higher nutrient contents and reach levels of micronutrient concentrations and biological stability equivalent to existing compost streams.[31] However, similar to compost, maximizing digestate nutrient content can be difficult, as dry AD feedstock quality, feedstock throughput, and processing conditions vary greatly throughout the day. In addition, as fertilizers are used for immediate nutrient uptake and short-term yield increases, there is seasonal variation in fertilizer demand which impacts dry AD production decisions.[22] Of those dry AD facilities producing fertilizers, their output is approximately nine thousand tons of solid fertilizer and seven million gallons of liquid fertilizer per facility per year. To produce fertilizer, dry AD facilities must invest in nutrient recovery infrastructure. The process separates dry and liquid portions of the digestate, and extracts fiber, ammonia sulfate, and phosphorus rich solids - each of which capture a higher value than digestate.[32]

Potential Dry Anaerobic Digestion Policies

Given the range industries with which dry AD facilities interact, several local and state policy mechanisms can significantly impact facility feasibility. The variability in policy interaction introduces additional uncertainty for policy makers in the decision making process. It is difficult to understand which policies best suit which types of dry AD facilities. For the solid waste industry, local and state municipal solid waste and organic solid waste diversion mandates, hauler source separation requirements, and material recovery facility quality standards all have considerable influence over feedstock supply and quality. Local air quality management districts' permitting and compliance structures determine facility's electricity and fuel output, as odor, greenhouse gas, and criteria pollutant thresholds bind combustion and refinement capacity. State public utility commission feed-in-tariffs can encourage electricity production, as fixed long term electricity sale prices can be higher on average and less volatile than wholesale prices. State and federal renewable fuel credits as well as state public utility commission pipeline interconnection subsidies can incentivize fuel production. The allowance of digestate land application as well as organic certifications can add value to digestate end products.[33] It is important for policy makers to consider all these variations while creating legislation.

Table 2: Policies Engaging with Dry Anaerobic Digestion Facilities

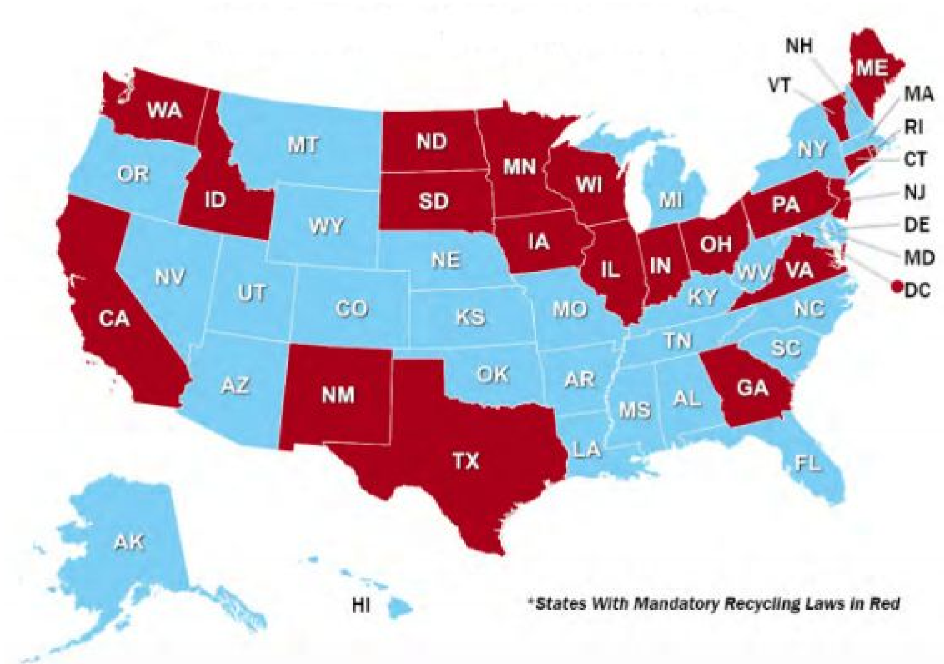
Upstream	Facility	Downstream
State Waste Diversion Mandates	Air Quality Permitting	Feed-in Tariffs
Organic Certifications	Hazardous Waste Requirements	Renewable Portfolio Standards
Landfill Bans	Material Recovery Permitting	Renewable Fuel Credits
Municipal Waste Legislation		Food Safety Standards

Solid Waste Diversion

Legislation which diverts disposed solid waste from landfill aspires to state and municipal ambitions surrounding consumption reduction, product reuse, product remanufacturing, and greenhouse gas reductions. Those states with enacted diversion policies have advanced secondary material management infrastructure with services which range from hauling, processing, distribution, and remanufacturing. And especially now, given China's recent solid waste import ban and its subsequent global demand shortfall, states are expanding such infrastructure to meet diversion mandates.[34] States which readily divert organic solid waste in particular can contribute to dry AD facility feedstocks and mitigate landfill methane emissions.

As of 2017, twenty-two states require at least one type of disposed material to be recycled, rather than landfilled.[35] These mandatory recycling requirements focus on materials that generate large environmental remediation costs, secondary remanufacturing revenue streams, or secondary processing costs. Lithion-Ion batteries, for example, have levels of lead, cobalt, copper, and nickel which contribute to both human and ecosystem toxicity[36]. As demonstrated by California markets, secondary aluminum and dry paper material maintain value and contribute to diverse end markets, whereas glass - due to it's heavy weight and fragility - frequently contaminate commingled streams.[37,38]

Figure 2: States with Mandatory Recycling Laws[35]



States and municipalities which target organic waste disposal are particularly advantageous for dry AD facilities. As the greenhouse gas impact and potential revenues sources of organic waste are being recognized by the global community, states are beginning to adopt organic waste disposal bans and reduction requirements.[39] As of now, five states are targeting organic waste disposal. Both California and Vermont feature expansive organic diversion requirements. Vermont's Universal Recycling Law requires 100 percent diversion of food waste from state landfills by 2020 from residential, commercial, and industrial sectors.[40] California requires 75 percent of all organic waste material types by 2025 from all sectors as well. California's regulation also targets organic waste separation and quality.[39] Similar to Vermont, Connecticut, Massachusetts, and Rhode Island require 100 percent diversion of organic waste, however only from commercial and industrial sectors.[41] As for municipalities, Austin, Texas; New York, New York; Portland, Oregon; San Francisco, California; and Seattle, Washington all require commercial food waste diversion and a degree of residential source separation.[42] It is common for municipal waste diversion programs to send all organic waste to be composted, which can create excess supply that pushes downward on compost prices.

Air Quality Requirements

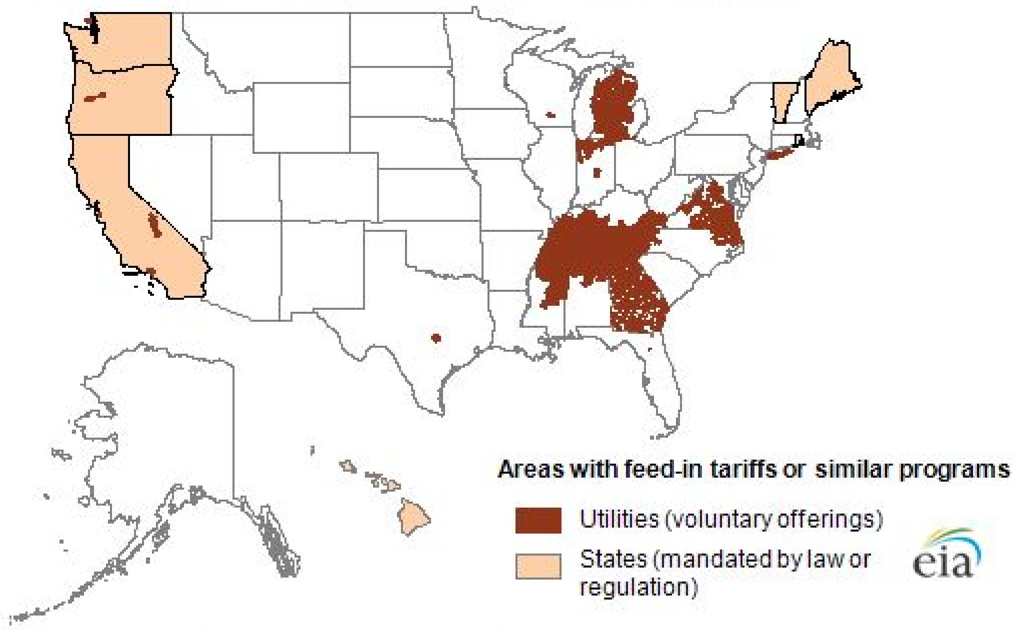
Dry AD facility electricity production and biogas refinement can pollute significantly. Enforcement of national and state air quality requirements will determine dry AD facility investment decisions and overall feasibility. As a regulatory baseline, United States Environmental Protection Agency determines allowable thresholds for criteria and greenhouse pollutants like carbon monoxide, lead, particulate matter, ozone, nitrogen dioxide, and sulfur dioxide as authorized by the federal Clean Air Act.[43,44] States can expand pollutant criteria and thresholds or defer to federal enforcement. In some cases, like in California, air quality legislation is expanded and enforcement is localized by districts.

Regardless of enforcement authority, dry AD facilities require permits to operate which determine pollutant thresholds and operational behavior. As dry AD is an emerging technology in the United States, enforcement authorities may but unable to accurately predict facility pollution levels. The permitting process can be lengthy and delay facility operations. After acquisition, breaching permit conditions may result in fines or temporary facility closure.[3]

Feed-In Tariffs

The performance-based incentives provided by a feed-in tariff (FiT) can guarantee long term dry AD facility electricity sales at marginal cost or higher. Either mandated by states or voluntarily provided by utilities, FiTs encourage renewable electricity production technology development. Contracted electricity sale prices are often higher than retail rates and fixed, such that small producers with intermittent or variable generation can remain solvent while avoiding price volatility. Some FiTs set an electricity sale price which declines to meet retail rates as a means of encouraging technological improvements that meet competitive marginal costs.[45,46]

Figure 3: U.S. States and Utilities with Feed-In Tariffs or Similar Programs[47]



In the United States, six states require FiTs and utilities in eight other states voluntarily offer FiTs. Of those states, California, Hawaii, Rhode Island, Vermont, Washington and Michigan explicitly recognize dry AD technology as a renewable energy technology eligible for their FiT.[47] However, despite this eligibility, the FiTs may have excessive requirements that dissuade facilities from enrolling. Small independent producers may not have the knowledge or resources to navigate the performance and reliability requirements outlined by the utility to enroll.[3,48] Utilities may also have limited uptake, enrolling only priority renewable technology types and delaying dry AD facility deployment.[49]

Pipeline Interconnection Subsidies

Interconnection subsidies can reduce the significant capital cost of pipeline installation for dry AD facilities. There are currently five facilities which divert food waste to produce biogas for the national natural gas pipeline grid - four in California, one in Ohio, and one in Illinois.[50] Of those states, only California provides an interconnection subsidy of up to 50 percent of interconnection costs or $3 million - whichever is lower.[51] For a dry AD facility, the biomethane upgrade facility and point of receipt can range from $1.1 to $1.7 million while the pipeline required to interconnect ranged from $50 - $300 per foot. If, for example, the facility is built one mile from the utility pipeline the cost to interconnect could be between $1.4 million and $3.3 million. Aside from capital costs, the facility is also responsible to maintain the refined biogas quality and the pipeline segment, contributing to additional variable maintenance costs.[52,53]

Renewable Fuel Credits

In addition to interconnection subsidies, dry AD facilities can receive credits for low carbon renewable fuel production. Facilities in any state are eligible to participate in the federal Renewable Fuel Standard (RFS) Program. Participating facilities earn credits called Renewable Identification Numbers (or RINs) based on their fuel output which refiners of fossil fuel based gasoline and diesel are obligated to purchase. There are different categories of RINs depending on the fuel type, each with an independent trade market. The categories range from renewable fuel (D6), advanced fuel (D5), biomass based diesel (D4), cellulosic biofuel (D3). Dry AD facilities are eligible to participate in D3 and D5 fuel pathways.

Figure 4: Weekly D3, D4, D5 and D6 RIN Prices[54]

As each fuel category can be produced by several upstream markets, it can be difficult to predict RIN supply, price stability, and resource spillovers. For example, a recent reallocation of U.S. maize supply to ethanol production may cut supply for other eligible fuel sources. In addition, a minimum output is required for participants, which may not be met if the fuel production market and technology is immature. Since the program start, feedstock costs for biomass based biodiesel production have not declined and cellulosic biofuel production technology has minimally improved.[55] Given the considerable price differential, dry AD facilities may be encouraged not to process food waste in order to receive the higher priced D3 RIN. Enrollment into the program may take as long as the facility deployment itself.[54,56] Such disincentives and delays may limit the diversion capabilities and environment benefits of the program.

In an effort to lower the carbon intensity of their fuel sector 10 percent by 2020, California started their own alternative fuel credit market place, in addition to the federal RFS program, called the Low Carbon Fuel Standard (LCFS). The California Air Resources Board (CARB) determines the lifecycle carbon intensity of each alternative fuel and allots credits to participating producers respectively. The LCFS features more fuel categories than the federal RFS, which include electricity and hydrogen production, and the marketplace expands to Oregon, Washington, and British Columbia; Canada.[57] In an attempt to increase consumer protection, CARB also mandates a price cap expecting credit purchases to continue even in cases of credit shortfalls and market price spikes.

Although dry AD facilities are eligible to earn low carbon fuel credits for compressed natural gas (CNG) production, California markets are the least mature for advanced low carbon fuel production. To meet low carbon intensity objectives, ultra low carbon eligible fuels, like CNG from organic waste AD, are imported from out of state due to a local supply shortfall. Given the price ceiling, the competitive market price may not efficiently adjust to reflect additional supply and the marginal cost of transport. Distortion in price signals compounded with market and political certainty due to the novelty of the program, disincentivizes in state dry AD investment.[58]

Organic Certifications

Dry AD digestate can attain value adding organic certifications for compost production or maintain the certifications of organic agriculture producers. However, such certifications can be difficult to achieve if municipal solid waste feedstocks contain inorganic contamination or if direct manure or food waste feedstocks have petrochemical contaminants. Both must meet organic quality standards set forth by the USDA National Organic Program and the Organic Materials Review Institute (OMRI) to be eligible for value adding organic certification. Contaminants like plastic, glass or colored paper found in the digestate disqualifies compost from attaining these certifications and limits the digestate's value.[59] Digestate specific standardization and certification programs are much less developed. The American Biogas Council introduced the Digestate Standard Testing and Certification program in 2016 as a voluntary, industry-led initiative to set quality management systems and testing procedures for digestate in the U.S. However, current participation in and effectiveness of the program is not known.

Food Safety Standards

State health and safety standards determine whether dry AD digestate or fertilizers derived from digestate can be directly applied to agriculture land. In conditions where organic waste feedstock is produced onsite, processed onsite, and nutrients applied onsite (like the case of on-farm anaerobic digestion), such conditions are exempted from regulation in nine states. Four states allow dry AD facilities to accept offsite organic waste streams and then sell digestate directly for land application, after facilities acquire permits.[33] This digestate must meet food safety standards set by the Department of Agriculture's Food Safety Modernization Act, otherwise farmers cannot sell their produce.[60]

Methodology

To capture all of the formerly described market and regulatory variation impacting facility solvency, I develop a financial model that calculates the annual cash flow, NPV, and IRR for dry AD facilities ranging from a 22,500 to 270,000 tons per year capacity with a 25 year lifetime. The model is generalized and expanded from a financial model developed by Lawrence Berkeley National Laboratory for the Zero Waste Development Energy Company's (ZWEDC) dry anaerobic digestion facility in San Jose, California. Six facility configurations are considered: electricity production, electricity production with onsite composting sales, electricity production with fertilizer sales, electricity production with district heating, compressed natural gas refinement with onsite sales, and compressed natural gas refinement with off site sales. I analyze these facility capacities and configurations in seven state contexts: California, Connecticut, Hawaii, Minnesota, Oregon, Vermont, and Rhode Island. I derive assumptions from empirical and financial data from ZWEDC, other financial models, and market data. I conduct net present value, single variate sensitivity, and break even analysis to determine a generic facility's financial solvency and required policy supports to reach solvency as measured by a NPV above zero dollars.

Model Inputs

Waste Data

The model can input several inbound waste streams defined by their waste type, fraction of intake, percent of inorganic residual, moisture content, and carbon content. For this analysis, the facility fully intakes only one waste stream with 25% inorganic residual, and moisture content of 70% and a carbon content of 53%. Such a waste stream would resemble a commercial source separated waste stream divided into wet and dry bins. The residual content of the waste stream is manually removed and trucked to landfill.

Operational Data

Base facility operational and maintenance (O&M) data and costs are adapted from the ZWEDC facility. Such data provides empirical values for electricity consumption (~108,000 kWh per month), number of full time employees (20-21), biogas yields (2500 ft3/ton waste), flared or lost biogas (25 percent), digester capacity factor (90 percent), and biogas methane content (55 percent). O&M costs for the facility include operational needs such fuel, materials, and parts, maintenance and testing, and equipment rentals, along with business expenses such as office supplies, legal and accounting services, taxes, and insurance.

Financial Data

Payment periods, finance lifetime, and finance rates are similarly adapted from the ZWEDC facility. The model calculates the total financed cost of capital and amortizes it over the expected life of the facility in order to calculate annual average costs and per-ton processing costs. The finance lifetime used for all capital assets is 15 years at a rate of 7 percent.

Facility Configurations

The model captures six possible facility configurations, and includes or excludes ancillary capital, O&M, and revenue streams accordingly. All capital and O&M costs noted below assume a facility with a 90,000 ton per year throughput. See Appendix A for a detailed table of considered streams for each configuration.

Electricity

The electricity configuration transforms organic waste into biogas, combusts the produced biogas into electricity, and landfills the residual digestate. Facilities earn revenue from accepting incoming organic waste as tipping fees. Some costs of disposal are reduced, as 10 percent of the waste the facility is able to sort out as recyclables. The recyclables, as part of the 25 percent of inorganic residual found in the organic waste, are sent to recycling facilities and landfills. Trucked at a price of $8 per ton, recycling facilities accept the waste at $38 per ton and landfills at the state average landfill price. The facility and CHP unit both have associated capital, O&M, and labor costs, based largely around the ZWEDC facility. The CHP is priced at $1,100,000 with a $50,000 yearly O&M cost. The facility trucks digestate produced from anaerobic digestion at $10 per ton to either a landfill or compost facility at the state average landfill price. Electricity production requires interconnection to transmit the electricity to the regional utilities grid infrastructure.

District Heating

The district heating configuration is equal to the electricity configuration except electricity is only partially generated, the facility invests in additional district heating infrastructure, and the facility receives additional sales in form of thermal energy. I base the ratio between electricity and thermal production (Brayton and Rankine cycles) from the existing six dry AD facilities in the US producing thermal energy.[2] I price thermal energy as the 2017 average regional wholesale natural gas price divided by a boiler efficiency of 30 percent.[61,62] Variable district heating customer interconnection and installation depends on the amount of thermal energy produced which I price at $0.038 per kiloWatt-hour.[63]

Onsite Compost

The onsite compost configuration is equal to the electricity configuration except instead of the facility bearing digestate trucking and disposal costs, the facility invests in compost capital and labor and sells finished compost. I derive the compost capital ($44640) and labor assumptions (1 FTE) from the ZWEDC facility. As little market data is available for compost nationally, the value of finished compost reflects prices of select existing composting facilities for 2019.

Fertilizer

Like the onsite compost configuration, instead of the facility bearing digestrate trucking and disposal cost, the facility invests in nutrient recovery infrastructure. The model uses costs cited from Khachatryan et al. 2011 whom conduct an economic feasibility assessment for nutrient recovery of digested manure feedstocks. This infrastructure capital cost is $540,000 with a yearly O&M cost of $100,375. The digestate is processed into fiber, ammonia, and phosphorous solids - priced at $10, $250, and $150 per ton respectively.[32]

Compressed Natural Gas Onsite

Rather than purchase a CHP unit to produce electricity, dry AD facilities can purchase biomethane upgrading infrastructure to refine biogas into compressed natural gas. This configuration assumes equal tipping fees, trucking, and facility capital and O&M costs as the electricity configuration, however it replaces CHP capital and O&M assumptions with a point of receipt upgrading station costing $6,000,000 with a yearly O&M expense of $100,000.[64] The facility sells compressed natural gas using a medium sized fast flow fueling station priced at $700,000[65] to fuel municipal hauling fleets.

Compressed Natural Gas Off Site

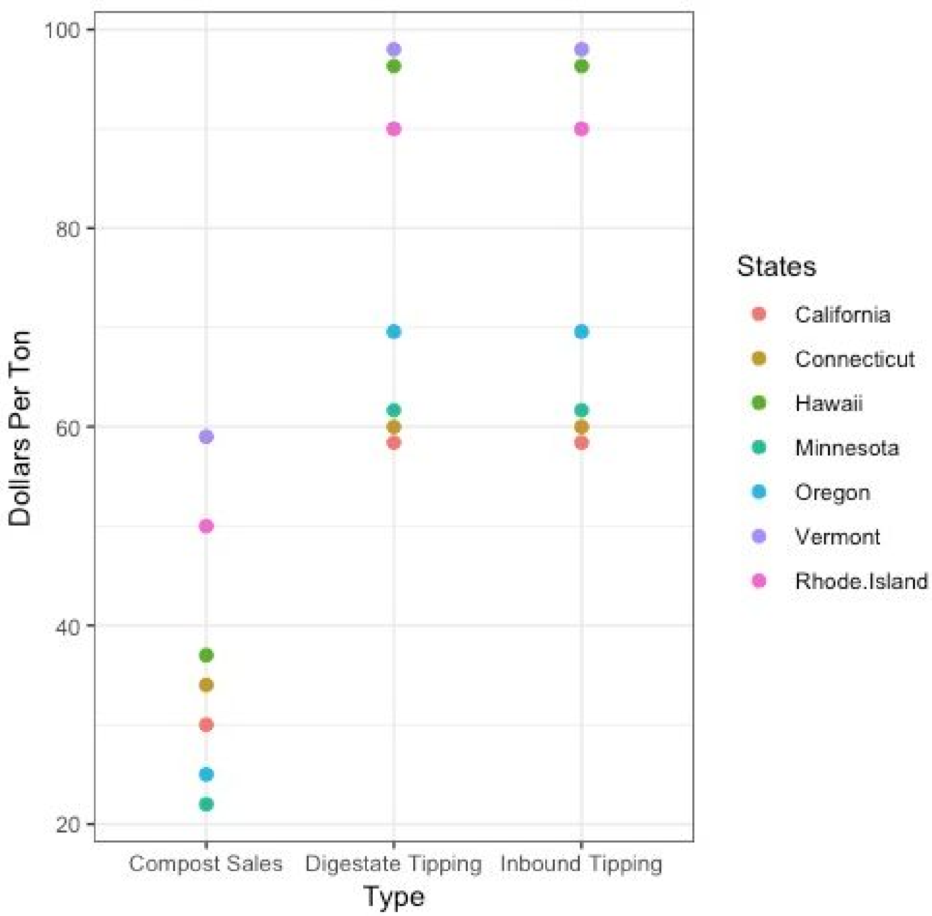
Here, rather than selling compressed natural gas on site, the facility purchases additional infrastructure to sell compressed natural gas on the national pipeline grid.

The facility constructs a point of receipt for $1,500,000 and one mile worth of pipeline priced at $150 per foot to feed compressed natural gas to the grid.[66]

State Variation

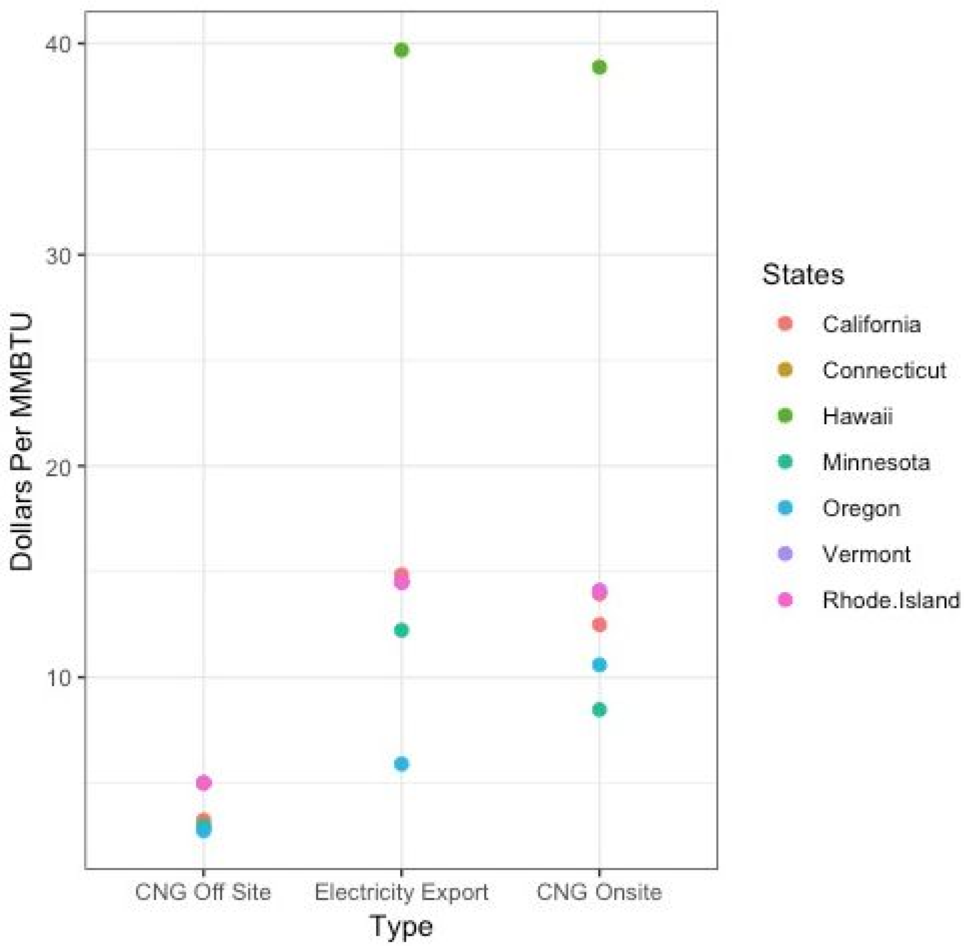
The model captures cost and revenue variation through seven states: California, Connecticut, Hawaii, Minnesota, Oregon, Vermont, and Rhode Island. I select these states as they have either a mandate to divert more than 50 percent of municipal solid waste from landfill or a mandate to divert residential organic solid waste. Such requirements establish the infrastructure and motivation necessary for dry anaerobic digestion facilities to exist. Of the total cost and revenues per facility, the following are varied per state context: facility capital, site capital, full time employee salary, inbound and outbound tipping fees, compost sales, electricity sales, and compressed natural gas sales.

Figure 5: Inbound Waste, Outbound Digestate, and Compost Prices



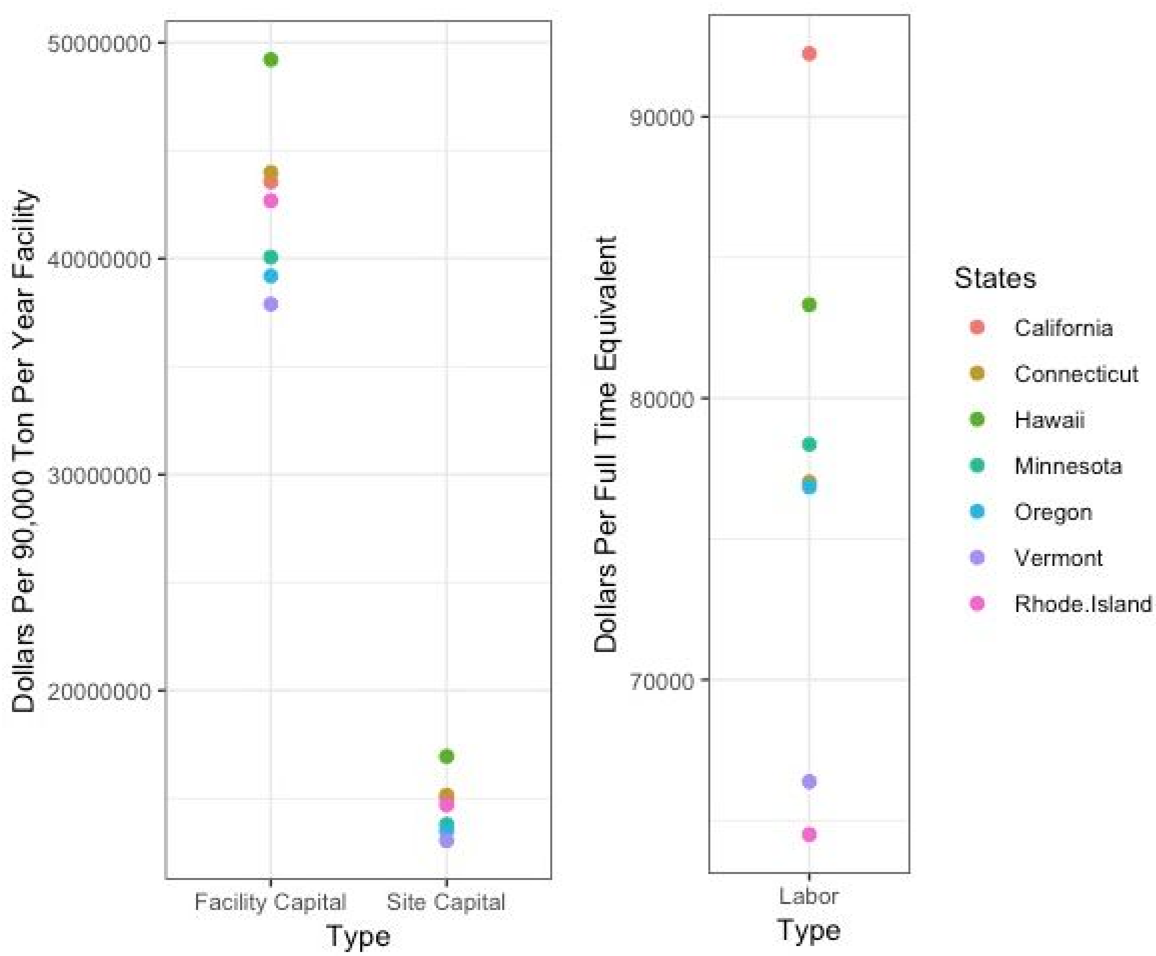
Both inbound and outbound waste tipping fees reflect the statewide average landfill price. They are both identical as an equilibrating mechanism for the function of facility inputs and outputs. Landfill prices represent the marginal cost of disposal.[67] In cases like Vermont and Connecticut where the statewide average landfill price was unavailable, I use publicly available mixed waste tipping fees from a single landfill[68] or a public disposal cost survey.[69] The prices range from $58.42 in California to $98 in Vermont per ton. As there are no publicly available statewide compost price surveys, I use individual facility prices for basic garden compost.[70–75]. The prices range from $22 in Minnesota to $37 in Vermont per ton.

Figure 6: Electricity, CNG Onsite and CNG Off Site Prices



I price electricity sales at the 2018 average regional wholesale rate.[61] In cases where wholesale markets don't exist, I use the regional utility's avoided cost for biomass electricity producers.[15] As wholesale rates and qualifying facility rates are both determined by the marginal cost of electricity production, I expect these rates to not vary significantly from one another, and consequently not significantly impact my results. Facilities can sell compressed natural gas on site to fuel municipal hauling fleets at the 2018 statewide residential average price.[76] The price the facility receives selling compressed natural gas offsite is equivalent to the nearest 2017 regional average wholesale natural gas hub price.[61]

Figure 7: Labor, Facility and Site Capital Prices



Facility and site capital expenditures I derive from the ZWEDC facility in San Jose, California. I vary this price across states using area modification factors derived from construction cost surveys.[77] Labor represents the 2017 annual average power plant operator wage per state.[78]

For an exhaustive table of model prices used, please see Appendix B. For details on operational, cost, and economic calculations, please see Appendix C.

Sensitivity, Elasticity, and Break Even Analyses

As the model calculates NPV and IRR, I can use these two metrics to determine facility solvency in a variety of configurations and state contexts. I define a solvent facility as one which has an NPV above zero and an IRR above 7 percent. I first test the base case for solvency, using all of the model assumptions formerly described. I then adjust single cost and revenue variables to the maximum sensitivity possible whose threshold is generated by existing market prices and regulatory mechanisms. This maximum serves to eliminate facility, state, and policy scenarios that are incapable of generating solvency. I then evaluate the elasticity of policy supports to facility solvency to determine which facility, state, and policy scenarios are most responsive to intervention. Of those policy interventions most impacting to facility solvency, I determine the modeled facility's breakeven revenue price and percent change required to achieve that price. This provides policy makers and industry alike a tangible metric for decision making.

The following cost and revenue variables are adjusted: facility capital, tipping fees, compost sales, electricity sales, and compressed natural gas sales. I bound each variable's sensitivity by existing market prices or policy supports. I adjust the sensitivities such that on average the variables meet these bounds. I reduce facility capital by up to 50 percent, as many states offer a 50 percent subsidy for digester deployment.[79] I increase tipping fees by up to 200 percent, which reflects the 2018 maximum average landfill price in the United States.[67] As compost sales are on average half of landfill prices, I increase compost sales by up to 350 percent, bounded by half of the 2018 maximum average landfill price in the United States. For electricity sales, I use the maximum feed-in-tariff price as our upper bound to raise electricity sale prices by up to 300 percent. For thermal sales, I similarly use the maximum feed-in-tariff price available which represents up to a 200 percent increase.[33] For compressed natural gas sales, I first add the federal RIN credits to the facility revenues using the 2018 average D5 RIN, then explore the facility potential to acquire a D3 RIN, which is priced up to 350 percent more.[54] In the case of California, I also add the credits earned from their Low Carbon Fuel Standard. For this price, I use the listed carbon intensity for dairy digesters which produce compressed natural gas of 13.45 gCO_2e/MJ and the average 2018 credit price of $160 to derive an additional $13.52 per MMBTU of compressed natural gas produced in California.[80]

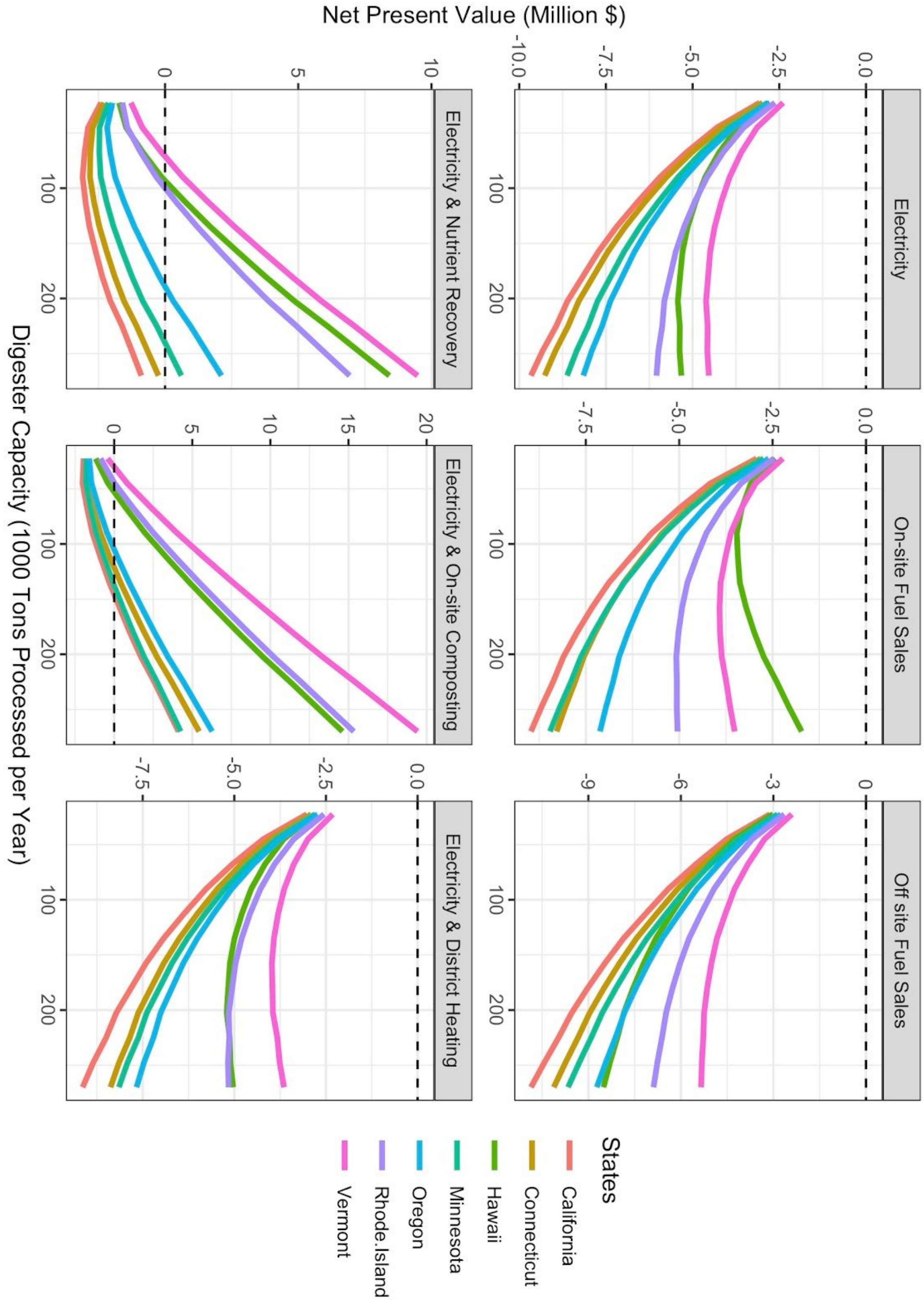
Results

This section describes the results of the baseline, sensitivity, elasticity, and break even analyses in terms of facility net present value, with internal rate of return results provided in the appendices. Whereas the baseline and sensitivity results are driven by the presumed cost and revenue inputs, the elasticities serve to demonstrate those relationships which do or do not determine facility solvency. This section builds on the prior discussion as a means of not only capturing market and regulatory variation but of determining the most suitable market and regulatory contexts for facility solvency. The section provides an example of break even analysis for Oregonian facilities as a means of providing tangible recommendations to Oregonian legislature and industry stakeholders.

Baseline Solvency

In order to breakeven without policy supports and experience positive economies of scale, facilities have to use a secondary revenue stream. Given the 42 possible state and facility combinations analyzed, only 12 reach a degree of solvency, all of which by producing fertilizer and compost. There are no states at any capacity in which a facility producing only electricity, providing district heating, or producing fuel for on site or off site sales reach solvency. Although district heating is a secondary revenue stream, it is benchmarked on the wholesale competitive price of natural gas, which is far too low to overcome high capital and waste disposal costs.

Figure 8: Baseline Net Present Value



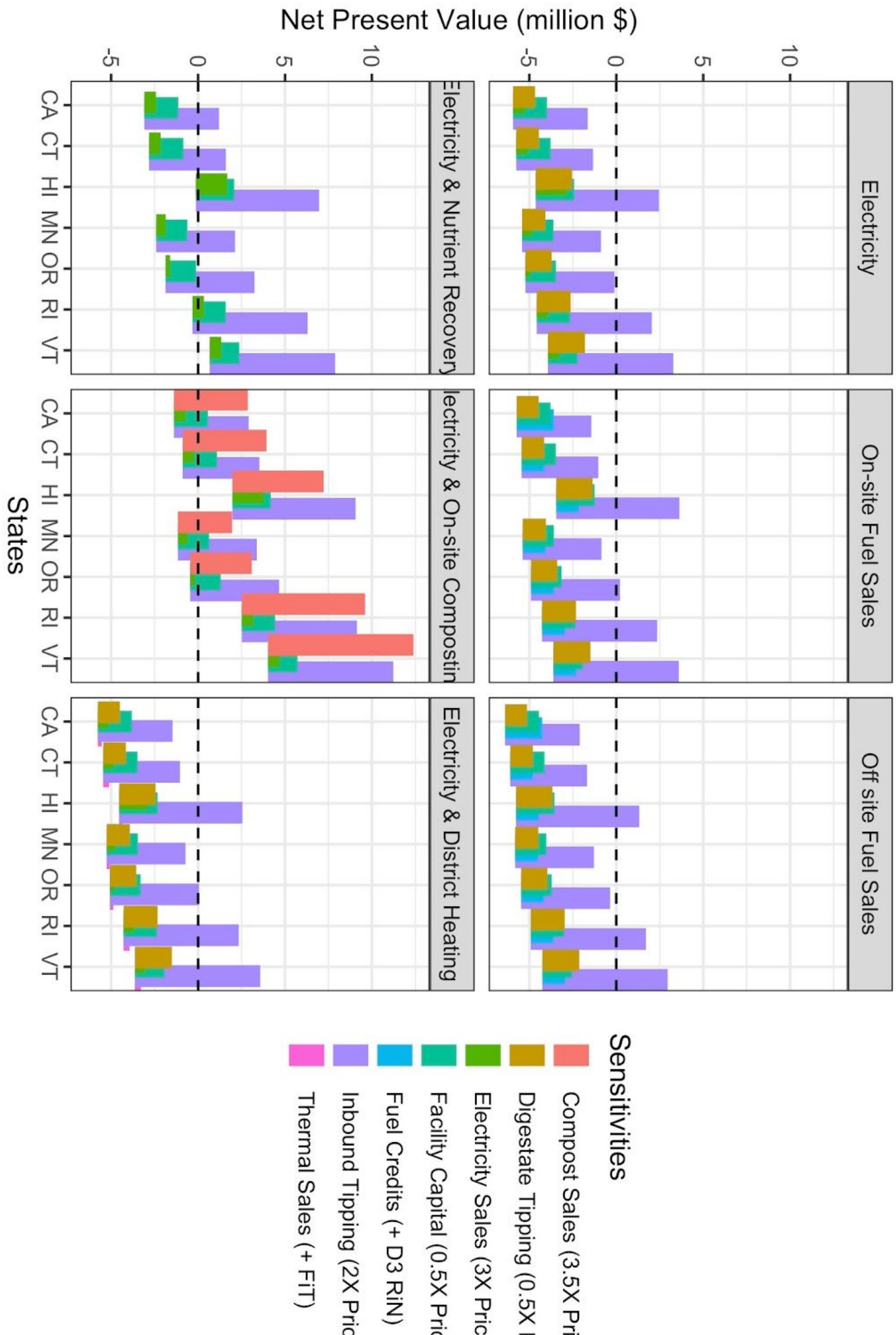
In all states facilities which utilize digestate to produce compost become solvent, and in five states facilities which utilize digestate to produce fertilizer become solvent at a certain capacity. In both cases, facilities which utilize this secondary revenue stream experience positive economies of scale. It is frequently the case that composting produces larger economies of scale than nutrient recovery. For onsite compost, a facility in Vermont and Rhode Island would require the lowest capacity of 45,000 tons per year and a facility in California and Minnesota require the largest scale up beginning to reach solvency at 157,500 tons per year. For nutrient recovery, Vermont would requires the least capacity to reach solvency at 90,000 tons per year while Minnesota would require the largest scale up at a capacity of 247,500 tons per year. Facilities in California and Connecticut, although experiencing positive economies of scale, do not reach solvency producing fertilizer in the bounds of my analysis.

Single Variate Sensitivity

Although the model can produce sensitivity results for a range of facility throughputs, here I demonstrate the sensitivity impacts on a 90,000 ton per year facility. I choose this facility capacity because I derive several cost assumptions from an existing 90,000 ton per year facility in San Jose, California. As such, the costs and revenues are most reasonably scaled to one another. I evaluate seven sensitivity scenarios: subsidizing (1) facility capital or (2) digestate disposal by half the current cost, (3) guaranteeing the maximum electricity sale price available as a feed-in-tariff of three times the current price, (4) providing additional revenue to facilities for accepting organic waste at two times the current price, (5) providing additional revenue to compost facilities accepting digestate by three and a half times the current price, and enabling facilities to access (6) fuel credits for compressed natural gas sales and (7) a feed-in-tariff for district heating.

Whereas before my baseline produced the minimum potential for facility feasibility, now each sensitivity scenario constrains facility feasibility using the maximum policy support required for dry AD facilities to exist today. A policy support which does not produce facility solvency given this maximum may be one not worth pursuing. Figure 9 shows the minimum and maximum NPV achieved from each market distortion.

Figure 9: Sensitivity Results for a 90,000 Ton Per Year Facility



Inbound Tipping

Most impacting is the price a facility receives for taking in organic waste. In 27 of 42 simulated contexts do facilities reach solvency when their incoming waste revenues are doubled. In California, Connecticut, and Minnesota solvency occurs when facilities are either producing compost or fertilizer. In Hawaii, Vermont, and Rhode Island solvency occurs in all facility configurations. In Oregon, solvency occurs when a facility provides district heating, produces fertilizer or compost, or upgrades compressed natural gas and sells it onsite.

Facility Capital Compensation

In the case that a 90K TPY dry AD facility were to have fifty percent of their facility's capital costs subsidized, in 10 of 42 simulated contexts would a facility reach solvency. In all seven states, a facility would be solvent while composting onsite, and in Hawaii, Rhode Island, and Vermont, a facility would be solvent producing fertilizer.

Electricity Feed-In-Tariff

If a 90K TPY dry AD facility were to access the highest priced feed-in-tariff in the United States, in 6 of 42 simulated contexts would a facility reach solvency. In Hawaii, Rhode Island, and Vermont, facilities producing either compost or fertilizer would become solvent.

Compost Sales

Increasing the compost price received by facilities up to three and a half times would allow facilities in all seven states which produce compost to reach solvency.

Insolvent Sensitivity Scenarios

Neither a reduction in digestate disposal fees, access to fuel credits, nor access to thermal feed-in-tariffs produce facilities in their applicable configuration in any state.

Sensitivity Responsivity

In addition to facility solvency, I evaluate the elasticity of NPV for all sensitivity scenarios. In other words, I evaluate to what percent NPV will increase for a facility if a given input changes by one percent. With weighted averages, I normalize and compare varying policy changes across state and facility configurations to determine the most significant cost and revenue drivers to facility solvency. Cases where an elasticity is greater than one are exceptional as returns to continued policy intervention are scaled positively in magnitude. Those elasticities less than one are likely not worth pursuing, as they are less impacting as the magnitude of the intervention increases. An overview of the elasticity results are demonstrated in Figure 10.

Sensitivity Scenarios

Table 3: Mean Elasticity of Net Present Value Per Sensitivity Scenario

Sensitivity Scenario	Elasticity of NPV (%)
Inbound Tipping (2X Price)	3.77
Facility Capital (0.5X Price)	2.43
Digestate Tipping (0.5X Price)	0.46
Electricity Sales (3X Price)	0.28
Compost Sales (3.5X Price)	0.25
Fuel Credits (+ D3 RIN)	0.17
Thermal Sales (+ FiT)	0.01

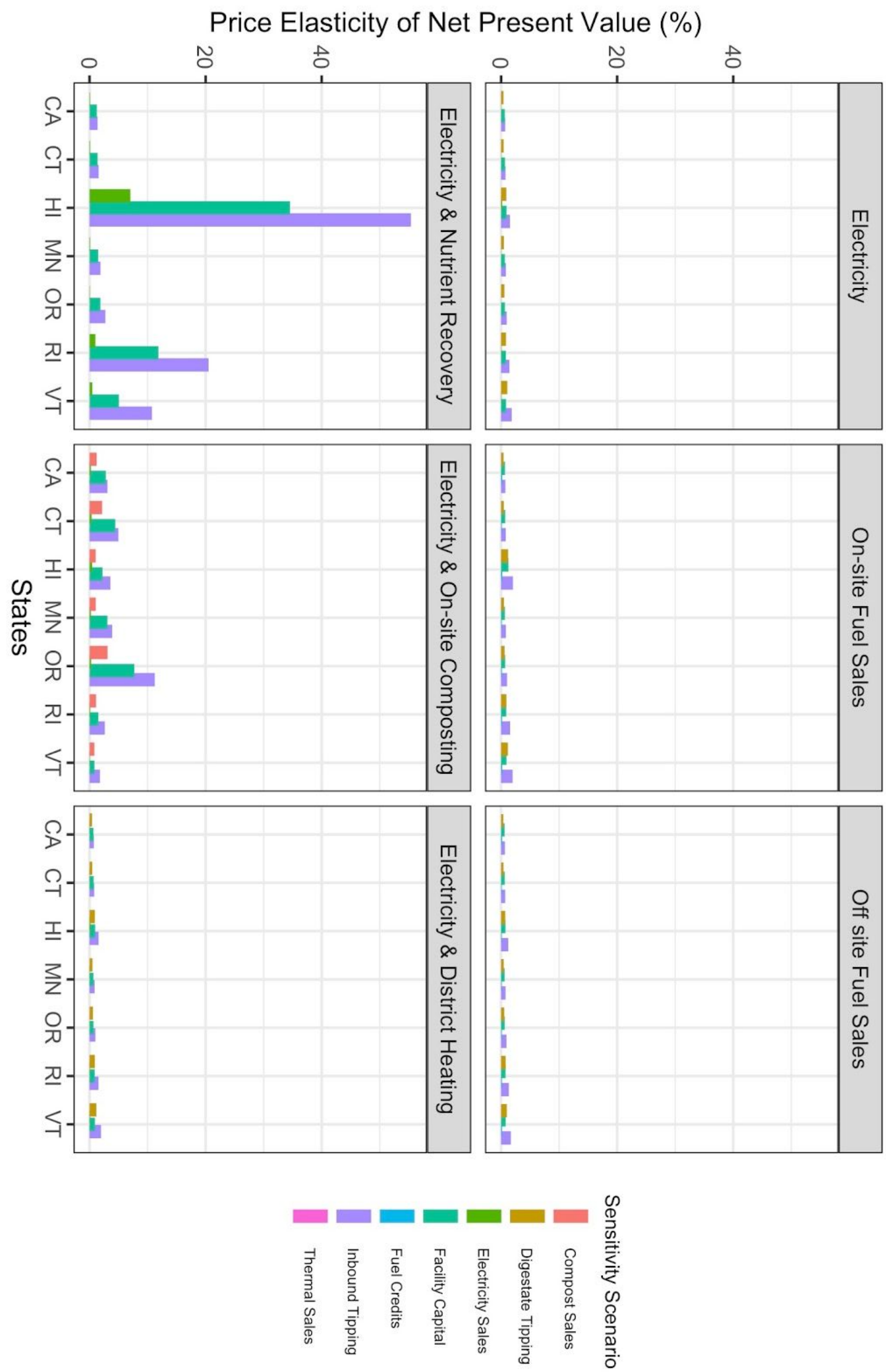
Of the seven sensitivity scenarios considered, supports to inbound tipping fees and facility capital are most responsive across state contexts and facility configurations. A one percent change in inbound tipping fees and facility capital results in a 3.77 percent and 2.43 percent increase in NPV, respectively.

Facility Configurations

Table 4: Mean Elasticity of Net Present Value Per Facility Configuration

Facility Configuration	Elasticity of NPV (%)
Electricity & Nutrient Recovery	2.94
Electricity & On-site Composting	1.32
On-site Fuel Sales	0.29
Electricity	0.27
Electricity & District Heating	0.26
Off site Fuel Sales	0.24

Figure 9: Price Elasticity of Sensitivity Scenarios for a 90K TPY Facility



Of the six facility configurations considered, supports to facilities which produce fertilizer or compost onsite are most responsive across state contexts and sensitivity scenarios. A one percent change in the average policy scenario for facility producing fertilizer or compost results in a 2.94 percent and 1.32 percent increase in NPV, respectively.

State Contexts

Table 5: Mean Elasticity of Net Present Value Per State

State	Elasticity of NPV (%)
California	0.02
Connecticut	0.05
Hawaii	0.71
Minnesota	0.04
Oregon	0.17
Vermont	0.27
Rhode Island	0.19

Supports to facilities in Hawaii are most responsive, regardless of facility configuration and policy support. A one percent change in the average policy scenario for facility in Hawaii results in a 0.71 percent increase in NPV.

Outlying Configurations and States

I also find that given a specific facility configuration, certain state contexts are exceptionally responsive to policy change. A one percent change in the average policy scenario for a facility producing fertilizer in Hawaii, Rhode Island, and Vermont results in a 3.98, 1.38, and 0.88 percent increase in NPV, respectively. And similarly for a facility producing compost in Oregon yields a 0.98 percent increase in NPV.

Break Even in Oregon

Of the sensitivity results, I select Oregon as a candidate for break even analysis. In three configurations, distortions to inbound tipping fees create near zero NPV. Given this policy support, facilities producing only electricity, generating fuel for on-site sales, and providing district heating services break even as they scale from 22.5K TPY to 270K TPY at prices of \$173-\$92, \$171-\$86, and \$171-\$90 per ton of waste accepted. Across all three scenarios, this represents a 25 to 150 percent increase from the original inbound tipping price.

Figure 10: Percent Increase from Original Price to Break Even in Oregon

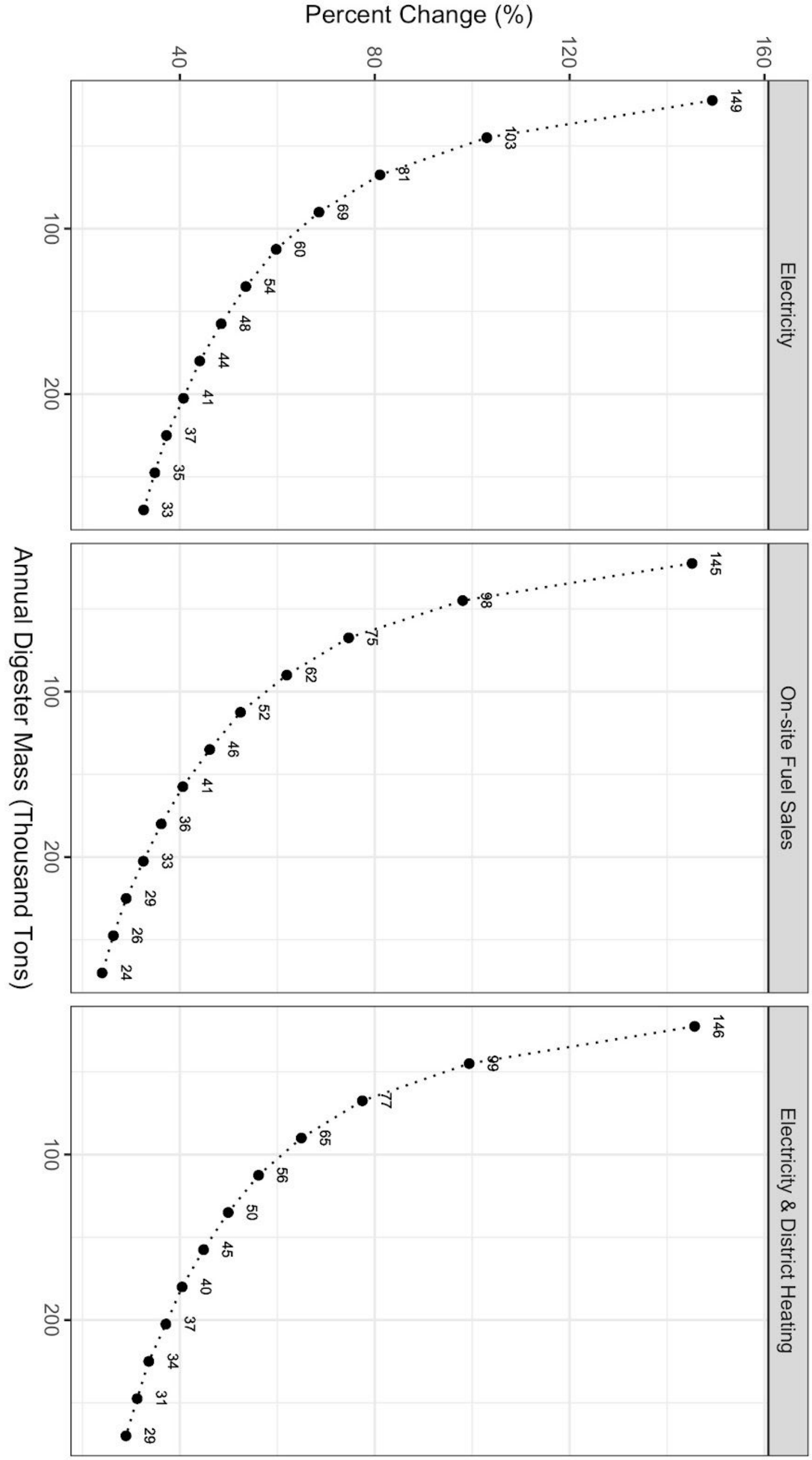
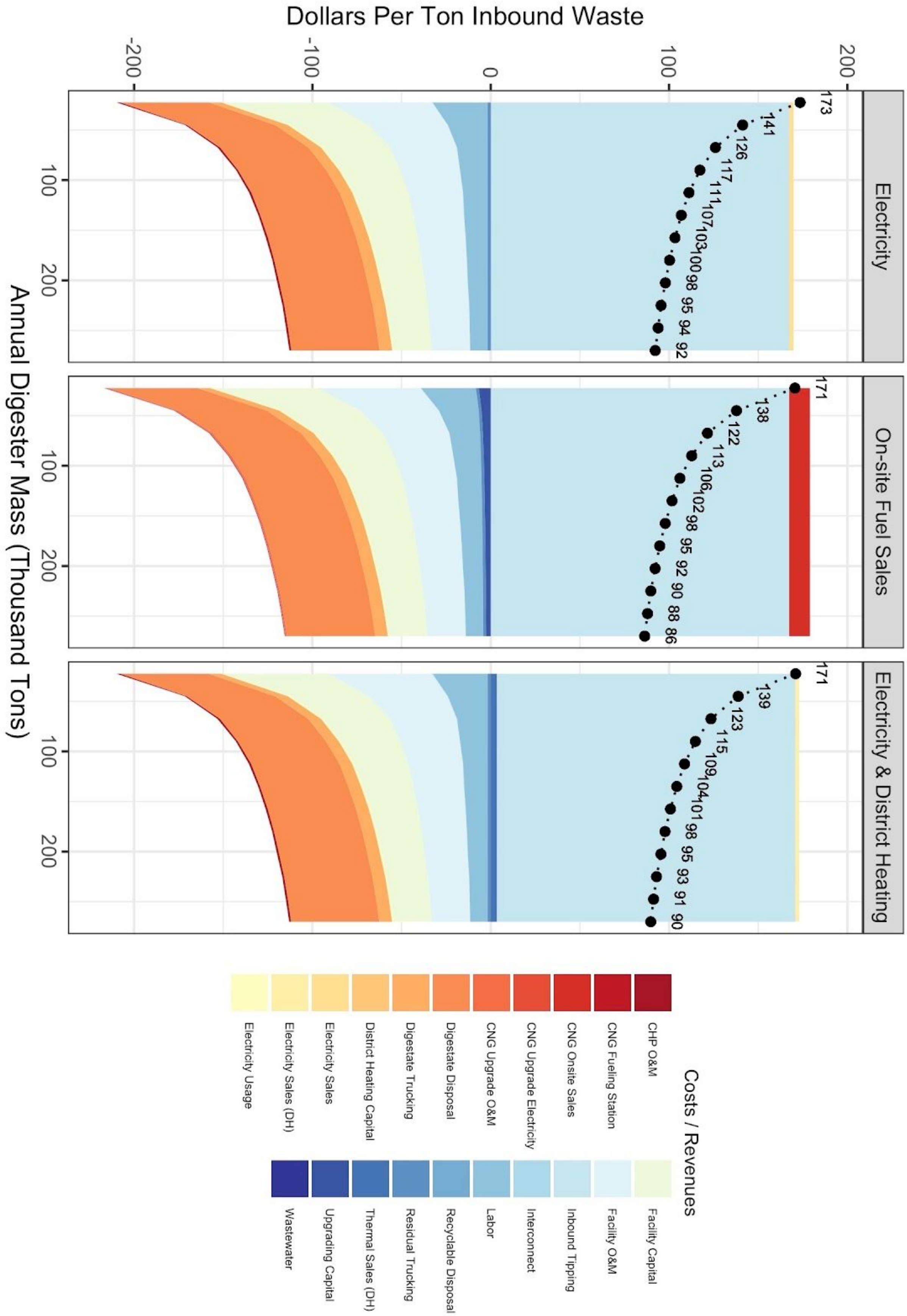


Figure 10: Breakeven Tipping Fee at Two Times Sensitivity in Oregon



Discussion

Supporting Secondary Revenue Streams

Electricity, district heating, or compressed natural gas sales alone are not adequate for dry anaerobic digestion facilities to be financially viable as they currently exist. As a single revenue stream, electricity and natural gas prices are almost always too low to offset facility marginal costs. However, when facilities capitalize from secondary revenue streams of significant value, especially those being compost and fertilizer, they can compensate for digestate disposal costs and benefit from positive economies of scale.

For this reason, policy supports which enable these secondary revenue streams or reduce disposal costs are critical for facility deployment. Such supports should incentivize digestate based composts or fertilizer markets, either through lowering the cost of disposal, subsidizing associated capital costs for value added digestate processing, or initiating environmental based labelling schemes for digestate products.

Compensating Waste Management and Construction Costs

Even though the states considered in this analysis have adequate waste management infrastructure, the resulting costs are still too high for facilities to overcome. States which either have higher costs of waste management (e.g. Hawaii, Vermont, Rhode Island) or lower construction costs (e.g. Vermont, Oregon) are particularly advantageous for dry AD facility deployment. Facilities which produce compost or fertilizer in these state contexts require less scale up to reach solvency and experience greatest positive economies of scale. Although electricity and fuel sales contribute less to facility revenues, facilities located in states with higher sale prices (e.g. Hawaii, Vermont) are capable of experiencing positive economies of scale at higher capacities.

Of the suite of potential policy supports examined in this analysis, facilities are most responsive to changes in their capital costs and incoming waste revenues. Facilities located in states like Hawaii, which feature higher than average marginal costs for waste management and electricity production and capital costs for dry AD facilities and land, are extremely receptive to policy intervention.

Regulation must prioritize reducing the costs of waste management in order to enable dry AD facilities. State regulators can subsidize facility capital costs, either through direct payments to merchant producers or improved rates of return for utility generators investing in dry AD. States or municipalities can offer premiums to haulers which sell organic waste streams to dry AD at a given price. Such supports are especially advantageous for facilities which produce compost and fertilizer, as they are counteracting excessive digestate disposal costs by transforming digestate into a value added products. States will also need to reduce barriers for facilities to access fertilizer and compost markets, either by exempting digestate based fertilizers from food safety standards, subsidizing the capital costs for accessing these technologies, or certifying non-profit or industry led digestate based labelling schemes. In addition to diversion goals, policies can target residential source separation, material recovery quality improvement, and ban inorganic residuals from incoming feedstock streams.

Incoming Waste Impacts

As exemplified by the break even analysis in Oregon, supporting incoming digester feedstocks are hugely critical. Such subsidies can enable facility configurations which otherwise are nearly impossible to achieve. To fully utilize this benefit, Oregon must guarantee dry AD facilities an inbound tipping fee 29% to 150% above their regional landfill price.

Conclusion

Dry anaerobic digestion is an underutilized technology in the United States capable of fulfilling many state environment goals by means of organic waste diversion, renewable energy production, and greenhouse gas mitigation. Contributing to this underutilization is the variety of markets in which dry AD facilities engage. Incoming municipal solid waste streams are highly contaminated, competitive electricity and natural gas prices are lower than facility marginal costs, and coproduct end markets are lacking. However, within many states exist policy supports which may benefit dry AD facilities. Solid waste diversion goals, electricity and thermal feed-in-tariffs, renewable fuel carbon credits, and coproduct certifications could potentially realize facility solvency. I develop a financial model to capture a suite of facility types, state variations, and policy changes to evaluate which policy supports most impact dry AD facility solvency and future investment. Through net present value, sensitivity, and break even analysis, I find that to overcome excessive facility capital and waste management costs facilities must access compost and fertilizer production infrastructure and end markets as well as receive a higher price for accepting incoming organic waste. As such I recommend the following:

Reducing facility barriers of entry to produce digestate based fertilizers and composts through capital subsidies or flexible standards

States can reevaluate food safety standards for digestate based fertilizers, subsidize the capital costs for accessing compost and fertilizer production technologies, and certify non-profit or industry led digestate based labelling schemes. Such methods would allow facilities to access a secondary revenue stream that would offset the excessive waste management and capital costs.

Increasing facility inbound waste revenues through lifecycle greenhouse gas based solid waste allowances

Many states offer supports for outbound facility electricity and fuel sales in the form of feed-in tariffs and renewable fuel credits, however no such price support exists for solid waste. Similar to California's Low Carbon Fuel Standard, a low carbon solid waste standard would price the externality produced by methanogenic organic waste and give dry anaerobic digestion facilities a comparative advantage to other solid waste processors as with fertilizer and compost configurations these facilities are net negative lifecycle greenhouse gas emitters.

Stimulating waste management efficiency gains and cost reductions through national stewardship vertical integration

Overcoming excessive waste management costs are critical to facility deployment. A historically decentralized and deregulated US waste management system has led to drastic efficiency losses due to overlapping and redundant infrastructure development. Similar to that of electricity and natural gas, solid waste too requires a period centralized vertical integration. As exemplified by British Colombia, Canada, system-wide efficiency gains can be achieved through regulated vertical integration proctored by stewardship organizations.

Appendix A: Method Assumptions

Table 6: Cost and Revenue Streams for Facility Configurations

Stream	Electricity	Fertilizer Production	Onsite Compost	District Heating	Onsite CNG	Offsite CNG
Electricity Consumption	✔	✔	✔	✔	✔	✔
Facility Capital	✔	✔	✔	✔	✔	✔
Facility O&M	✔	✔	✔	✔	✔	✔
Labor	✔	✔	✔	✔	✔	✔
Recyclables Disposal	✔	✔	✔	✔	✔	✔
Residual Trucking	✔	✔	✔	✔	✔	✔
Wastewater	✔	✔	✔	✔	✔	✔
CHP Capital	✔	✔	✔	✔		
CHP O&M	✔	✔	✔	✔		
Electricity Interconnect	✔	✔	✔	✔		
Digestate Tipping	✔			✔	✔	✔
Digestate Trucking	✔			✔	✔	✔
CNG Upgrade Station					✔	✔
CNG O&M					✔	✔
CNG Electricity					✔	✔
Compost Capital			✔			
Digestate Labor		✔	✔			
CNG Fueling Station					✔	
CNG Offsite Capital						✔
District Heating Interconnect				✔		
Fertilizer Capital		✔				
Fertilizer O&M		✔				
Tipping Fee Revenues	✔	✔	✔	✔	✔	✔
Electricity Sales	✔	✔	✔	✔		
Thermal Sales				✔		
Fertilizer Sales		✔				
Compost Sales			✔			
CNG Sales					✔	✔

Appendix B: Model Prices

Table 7: Cost and Revenue Prices

Category	California	Connecticut	Hawaii	Minnesota	Oregon	Vermont	Rhode Island
Trucking Residuals ($/ton)	8	8	8	8	8	8	8
Trucking Digestate ($/ton)	10	10	10	10	10	10	10
Electricity Interconnection ($K)	200	200	200	200	200	200	200
Electricity Purchased ($K/90K TPY Facility)	103	103	103	103	103	103	103
CHP Capital ($M/90K TPY Facility)	1.12	1.12	1.12	1.12	1.12	1.12	1.12
Facility Capital ($M/90K TPY Facility)	43.55	43.98	49.21	40.07	39.19	37.89	42.68
Site Capital ($M/90K TPY Facility)	15	15.15	16.95	13.8	13.5	13.05	14.7
Labor ($K / Full Time Employee)	92	77	83	78	77	66	65
Facility O&M ($M/90K TPY Facility)	3	3	3	3	3	3	3
CHP O&M ($K/90K TPY Facility)	50	50	50	50	50	50	50
Electricity Sold ($/kWh)	0.051	0.049	0.14	0.042	0.02	0.049	0.049
Wastewater ($/ton)	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Digestate Disposal ($/ton)	58.42	60	96.33	61.67	69.58	98	90
Recyclables Disposal ($/ton)	38	38	38	38	38	38	38
Compost Capital ($K/90K TPY Facility)	44.6	44.6	44.6	44.6	44.6	44.6	44.6
Inbound Tipping Fee ($/Ton Waste)	58.42	60	96.33	61.67	69.58	98	90
Biomethane Upgrade O&M ($K/90K TPY Facility)	100	100	100	100	100	100	100
Biomethane Upgrade Capital ($M/90K TPY Facility)	1.5	1.5	1.5	1.5	1.5	1.5	1.5
CNG Medium Fueling Station ($K/90K TPY Facility)	700	700	700	700	700	700	700
CNG Sales Onsite ($/MMBTU Biomethane)	12.49	13.95	38.88	8.47	10.59	14.12	14.02
RINs ($/Credit)	0.53	0.53	0.53	0.53	0.53	0.53	0.53
LCFS Credits ($/MMBTU Biomethane)	13.52	13.52	13.52	13.52	13.52	13.52	13.52
Point of Reciept + Pipeline Capital ($M/90K TPY Facility)	2.3	2.3	2.3	2.3	2.3	2.3	2.3
CNG Sales Offsite ($/MMBTU Biomethane)	3.23	4.99	2.95	2.89	2.74	4.99	4.99
Compost Sales ($/Yd3)	30	34	37	22	25	59	50
District Heating Capital ($/kWh)	0.037	0.037	0.037	0.037	0.037	0.037	0.037
Fiber Sales ($/ton)	10	10	10	10	10	10	10
Ammonia Sales ($/ton)	250	250	250	250	250	250	250
P Sales ($/ton)	150	150	150	150	150	150	150
Fertilizer Capital ($K/90K TPY Facility)	540	540	540	540	540	540	540
Fertilizer O&M ($K/90K TPY Facility)	100	100	100	100	100	100	100

Appendix C: Operational, Cost, and Economic Calculations

Operational Calculations

Masses

The starting point for each set of calculations in the model is the amount of organic mass that is to be processed in the digesters ($m_{digester}$) in terms of tons per year. For each scenario and state, I calculate financial metrics for facilities processing 22,500 TPY to 270,000 TPY. The majority of waste going into the digesters is from the organic fraction of municipal solid waste (OFMSW).

Incoming MSW contains a significant quantity of inorganic residuals. The facility receives tipping fees based on the total tonnage of incoming waste, not just the organic fraction of it, and therefore it is important to know this tonnage for revenue calculations. Additionally, there are costs associated with separating and disposing of residuals, so the tonnage of those materials must be known as well. The fraction of residuals in each waste stream ($f_{residual,i}$)) as well as each waste stream's proportion of total waste coming into the facility (f_i). From these values, I can calculate a weighted average residual fraction for all incoming waste ($\overline{f_{residual}}$), total municipal waste intake (m_{MSW}), and mass of residuals ($m_{residual}$).

$$m_{MSW} = \frac{m_{OFMSW}}{1-f_{residual}}$$

$$m_{residual} = m_{MSW} * \overline{f_{residual}}$$

The anaerobic digestion process causes a reduction in solid waste mass due to the transformation of mass into biogas as well as creation and loss of moisture. A 30% mass reduction is assumed from when the waste goes into the digesters to when the digestate is removed ($MassReduction_{digestion}$). This value is based on ZWEDC facility tonnage reports. In cases when the digestate goes through an aerobic composting process onsite, additional mass is lost to moisture evaporation and gaseous emissions. I assume a mass reduction of 10% in this process ($MassReduction_{compost}$), based on conversations with the ZWEDC facility. With these assumptions, I can calculate the mass of digestate coming out of the facility ($m_{digestate}$) or the mass of compost ($m_{compost}$) for scenarios when compost operations occur on-site.

$$m_{digestate} = m_{digester} * (1 - MassReduction_{digestion})$$

$$m_{compost} = m_{digestate} * (1 - MassReduction_{compost})$$

Biogas and Methane Production

The mass of methane generated (m_{CH4}) is calculated based on ZWEDC's average biogas yield per ton of digestate in 2017 (y_{ZWEDC}), multiplied by the theoretical density of methane (k_{CH4}).

$$m_{CH4} = y_{ZWEDC} * k_{CH4}$$

In cases where biogas is upgraded to compressed natural gas, I assume 10 percent of biogas is diverted for on-site energy use, 15 percent is lost in the process, and in cases of pipeline delivery an additional two percent is lost.

Electricity Generation

The quantity of electricity generated ($e_{electricity}$) is calculated using the mass (m_{CH4}) and heating value (HV_{CH4}) of methane, the CHP's brayton cycle efficiency ($\varepsilon_{brayton}$), and assumptions about biogas flaring and venting, expressed as the fraction of biogas that is sent to the CHP units (f_{loss}). I use ZWEDC's brayton efficiency of 41.6 percent in cases of pure electricity production.

$$e_{electricity} = m_{CH4} * HV_{CH4} * \varepsilon_{brayton} * f_{loss}$$

In the case of district heating, I assume a full CHP efficiency (ε_{CHP}) of 80 percent. I then divide the efficiency between the fraction of electricity ($f_{electricity}$) and thermal ($f_{thermal}$) production. I derive a fraction for electricity of 46.65 percent and a fraction for thermal of 53.35 percent from the existing six dry AD facilities in the US producing thermal energy.[2]

$$e_{total|district\ heating} = m_{CH4} * HV_{CH4} * \varepsilon_{CHP} * f_{loss}$$

$$e_{electricity|district\ heating} = e_{total|district\ heating} * f_{electricity}$$

$$e_{thermal|district\ heating} = e_{total|district\ heating} * f_{thermal}$$

In the case of upgrading biogas to compressed natural gas, the facility consumes electricity depending on the absorption material and pipeline column diameter. For this analysis I assume the facility upgrades biogas with an absorption material of Zeolite 13X which consumes electricity at 0.422 kWh per normal m3.[81]

Cost Calculations

The model uses the results of the operational calculations to calculate the costs and revenues involved in operating the facility. Costs are calculated for all categories, then are scaled or zeroed out depending on configuration parameters. For example, a configuration where compost does not occur will exclude the compost capital and labor costs, while a scenario where composting is done on-site will include these costs but exclude trucking and tipping costs for digestate. Each of the below calculations are performed for each waste intake level for each facility configuration, using unit costs which vary per state. Notation: c for unit costs per state, C' for total costs (for capital) per state, C for annual costs per state.

Capital and Site Costs

Capital costs are based on the size of the facility and generators needed to process the waste and energy estimated for each waste intake level. I scale the facility size from the original 90,000 ton per year ZWEDC capacity a power function based on the facility throughput (v_{waste}) and a factor of 0.6. [82]

$$N_{Facility} = \left(\frac{v_{waste}}{90{,}000}\right)^{0.6}$$

The number of CHP units required (n_{CHP}) is a step function of the amount of electricity being generated by the facility (e). I assume a set CHP size (s_{CHP}) due the fact that identical equipment will have more consistent and simplified maintenance, and more predictable consequences if an outage of any one generator were to occur. The capacity factor (CF) of the CHP units is the ratio of actual energy production to maximum rated production; I assume a maximum desired capacity factor of 0.8 for the facility. This allows energy production to fluctuate throughout the year without going over the generator's capacity.

The model currently assumes waste intake is consistent throughout the year, but if that assumption were to change then the facility and CHP units would need to be sized for the peak season, as long-term storage is not viable for organic waste and is not available at the facility for biogas. The model also assumes biogas flow is constant throughout the day, which is reasonable given that the digesters operate around-the-clock and only one digester (at most) out of sixteen is cleared out and refilled each day. If short-term biogas storage was to be installed at the facility, for example to maximize electricity revenues by selling only at peak times, the CHP units would need to be sized up accordingly.

$$N_{CHP} = 1 + [\frac{e}{365*24*CF} * \frac{1}{s_{CHP}}]$$

The "sticker" price of the facility (C'_{FacCap}) is then the number of facilities times the assumed unit price of the facility (c_{FacCap}), plus site development costs that do not scale with facility size (c_{site}). Site development for the ZWEDC facility included site foundations, which were expensive as the facility is built on landfill, bringing utilities to the site, on-site roads, storm water drainage, etc. Generally, constructing larger facilities could incur economies of scale beyond site development costs. However, due to the modular nature of the ZWEDC facility there is no reason to believe this would be the case.

CHP price (C'_{CHPCap}) is the CHP unit price (c_{CHPCap}) multiplied by the number of units. Compost capital ($c_{compost}$), CNG capital (c_{CNG}), and fertilizer production capital ($c_{fertilizer}$) are the unit price multiplied by the number of facilities. District heating capital ($c_{heating}$) are scaled by the thermal output which is a function of facility size. Compost capital, CNG capital, fertilizer production capital, and district heating capital are calculated separately, as this cost may or may not be present depending on the facility configuration.

$$C'_{FacCap} = N_{facility} * (c_{FacCap} + c_{site})$$

$$C'_{CHPCap} = N_{CHP} * c_{CHPCap}$$

$$C'_{CompostCap} = N_{facility} * c_{CompostCap}$$

$$C'_{CNG} = N_{facility} * c_{CNG}$$
$$C'_{HeatingCap} = e_{thermal} * c_{heating}$$

Actual capital costs are higher than the above prices due to long payment schedules and associated financing costs. Therefore, a loan payment function is used to calculate the monthly payment amount (PMT) of a loan for a certain principal (P), at fixed capital interest rate (r_c), over a set number of payment periods (p). A "capital lifetime" ($L(months)$) based on depreciation schedules gives the number of payment periods, while the calculated capital prices (C') are the principal, and the assumed interest rate is 5 percent. From this monthly payment, average annual costs (C) over the life of the facility ($L_{facility}(months)$) are calculated. In general, the capital lifetime is lower than the actual useful life of the equipment, so the total amortized costs will be lower than the payments the facility is currently making. I assume all equipment will last the full facility lifetime of 25 years.

$$PMT(r_c, p, P) = \frac{P * r_c/12}{1-(1+r_c/12)^{-p}}$$
$$C_i = PMT(r_c, p, P) * 12 * \frac{L_i}{L_{facility}}$$
$$for\ i \in facility, CHP, compost, CNG, fertilizer, heating\ capital$$

The final capital cost is the utility interconnection ($C_{interconnect}$). I assume the unit price ($c_{interconnect}$) is paid lump-sum at the start of the facility building process, and therefore the average annual cost is simply the cost divided by the lifetime of the facility in years.

$$C_{interconnect} = \frac{c_{interconnect}}{L_{facility}/12}$$

Labor Costs

Labor is calculated based on the approximate annual cost of one full-time employee (c_{labor}) and the number of employees required for the facility (N_{FTE}). Labor is divided into four types that scale differently with operational parameters, and the number of employees needed for each labor type is calculated based on a "base" facility. The "base" facility is representative of ZWEDC's operations and is characterized by number of employees (n_{FTE}) for each labor type, waste intake (m_{MSW}), residual fraction ($f_{residual}$), and digestate production ($m_{digestate}$). Adjusting from this known scenario allows us to estimate unknown labor needs at various facility scales and operational conditions.

Overhead labor ($N_{FTE,overhead}$) is a constant input that does not change with facility size or operating conditions. This assumption relies on the knowledge that I am only examining facilities up to three times the base operations. For facilities drastically larger or smaller, this assumption may be revisited. Operations labor ($N_{FTE,ops}$) scales with the size of the facility. Labor required for waste sorting ($N_{FTE,sorting}$) scales both with the amount of waste coming in and the residual level of that waste. Ceiling functions are used to ensure no fractional employees are included.

$$N_{FTE,overhead} = \lceil n_{FTE,overhead} \rceil$$

$$N_{FTE,ops} = \lceil n_{FTE,ops} * N_{fac} \rceil$$

$$N_{FTE,sorting} = \left\lceil n_{FTE,sorting} * \left(\frac{m_{MSW}}{m_{MSW,base}}\right) * \left(\frac{f_{residual}}{f_{residual,base}}\right) \right\rceil$$

$$N_{FTE} = N_{FTE,overhead} + N_{FTE,ops} + N_{FTE,sorting}$$

$$C_{labor} = N_{FTE} * c_{labor}$$

In cases where facilities produce compost onsite or recover nutrients from digestate, labor ($N_{FTE,compost}$) scales linearly with the mass of digestate being produced.

$$N_{FTE,compost} = \left\lceil n_{FTE,compost} * \left(\frac{m_{digestate}}{m_{digestate,base}}\right) \right\rceil$$

$$N_{FTE} = N_{FTE,overhead} + N_{FTE,ops} + N_{FTE,sorting} + N_{FTE,compost}$$

In cases where facilities upgrade biogas, I assume equivalent labor for electricity and district heating configurations. Ceiling functions are used to ensure no fractional employees are included.

Operations and Maintenance Costs (Non-Labor)

Operations and maintenance (O&M) costs are estimated at a high level. Annual costs per-facility ($c_{FacO\&M}$) and per-CHP unit ($c_{CHP O\&M}$) are assumed, and these values are simply multiplied by the number of facilities and CHP units for the total cost. Facility O&M includes parts, fuel, equipment rentals, and outside maintenance, as well as business expenses such as office supplies, legal, accounting, and consulting. CHP O&M is calculated separately because the number of CHP units does not scale exactly with the number of facilities, and the CHP maintenance cost is known from the facility's contract with the equipment manufacturer. I consider additional CNG and Fertilizer O&M costs which scale with facility size.

$$C_{fac\ o\&m} = N_{fac} * c_{fac\ o\&m}$$

$$C_{CHP\ o\&m} = N_{CHP} * c_{CHP\ o\&m}$$

Additional O&M costs include electricity ($C_{electricity}$), for which an annual per-facility cost ($c_{electricity}$) is assumed, and wastewater ($C_{wastewater}$), which has a per-ton unit cost ($c_{wastewater}$) that is multiplied by total intake mass. Although the facility generates more electricity than it consumes, electricity costs are calculated separately from electricity revenues because the rates paid for consumption and production are different. The electricity use scales linearly with the facility size, which scales with waste intake, due to the assumption that the majority of the facility's equipment will need to operate continuously regardless of how much waste is coming in. Wastewater treatment costs can be significant due to the high amounts of suspended solids and biological and chemical agents in the water that leaves the facility. A large portion of the facility's wastewater is produced at the extruders, which remove excess water from incoming waste and outgoing digestate. Therefore, wastewater costs are assumed to scale with the amount of waste being processed by the facility.

$$C_{electricity} = N_{fac} * c_{electricity}$$

$$C_{wastewater} = m_{total} * c_{wastewater}$$

Byproducts and Waste Materials

AD facilities have a number of materials to manage throughout their operational process. For each material stream, costs are incurred for both transportation of the material ($c_{trucking}$) and tipping fees paid to the accepting facilities ($c_{tipping}$).

As waste comes into the facility inorganic residuals are sorted from the organic material. The vast majority of residuals must be landfilled, while other recyclables may be discarded at specialized facilities due to their value or because of contractual obligations. The total mass of residual is calculated as previously discussed, then assumed fractions for landfill ($f_{landfill}$) and recyclables ($f_{recyclables}$) are used to calculate their respective masses. Digestate is sent to either a landfill or compost facility under current most configurations. The costs of managing these materials are simply the mass of the material times the sum of per-ton trucking and tipping fees. In configurations where facilities utilize digestate to create additional value, these cost of trucking and landfilling digestate would be zero.

$$C_i = m_{residual} * f_i * (c_{trucking,i} + c_{tipping,i})$$

$$C_{digestate} = m_{digestate} * (c_{trucking,digestate} + c_{tipping,digestate})$$

Revenues

The primary source of revenue for the facility is incoming tipping fees. These fees are set by contract with the various haulers that send waste to the facility. The waste data input file can assume tipping fees for multiple incoming waste streams along with the fractional breakdown of incoming waste across streams. Therefore, a weighted average per-ton tipping fee (r_{tipfee}) can be calculated for the given waste scenario and multiplied by the total intake mass to calculate tip fee revenue (R_{tipfee}). In the case of this analysis, a single waste stream is fully utilized by the facility, the tipping fee for which varying per state.

$$R_{tipfee} = m_{MSW} * r_{tipfee}$$

The facility can make money by selling electricity. The structure of electricity revenues vary widely based on a regional wholesale or qualifying facility avoided cost rate. They can also vary based on a facility's location, customer, or what local laws and rate structures look like. Based on each state electricity price, I calculate electricity revenue ($r_{electricity}$) using a baseline rate (α_{elec}) and an average monthly adjustment factor (). The adjustment factor is calculated from a set of multipliers for each season and time of day described in the contract; these multipliers represent when electricity is more or less valuable to the utility. Hypothetically, facilities could optimize operations to generate electricity at times with peak adjustment factors, but this is generally not feasible with current biogas storage capacity and other operational logistics and would likely require the installation of additional CHP units.

$$R_{electricity} = e * r_{electricity} * \left(\frac{1}{12} * \sum_{m=1}^{12} \alpha_{elec,m}\right)$$

A facility can create an additional revenue stream by composting digestate on-site and collect revenues from the sale of the final compost. The total revenue ($R_{compost}$) is simply the mass of compost created multiplied by an assumed per-ton price ($r_{compost}$).

$$R_{compost} = m_{compost} * r_{compost}$$

The facility can create an additional revenue stream by selling thermal energy ($R_{thermal}$) through district heating. For this configuration, I assume the thermal equivalent for the competitive wholesale price of natural gas ($r_{naturalgas}$) as the typical boiler fuel divided by the boiler efficiency (k_{boiler}) to derive the revenue. And additional 12 percent of losses are assumed during distribution (f_{loss}).

$$R_{thermal} = e_{thermal} * \frac{r_{naturalgas}}{k_{boiler}} * f_{loss}$$

The facility can create an additional revenue stream by recovering nutrients from digestate. Both solid and liquid fractions of the digestate have varying levels of fiber, ammonia sulfate, and phosphorous solids. I assume the wet and dry content (f) of digestate is 75 and 25 percent, respectively, and densities (d) of 700 and 998 kg/m3 for each. For wet fiber, ammonia, and phosphorous recovery (k_{wet}) I assume a rate of 90, 25, and 120 kg/m3 and for dry fiber, ammonia, and phosphorous recovery (k_{dry}) I assume a rate of 22.5, 7.5, and 30 kg/m3. Each recovered nutrient has an associated market price, which does not vary per state.

$$R_{fiber} = r_{fiber} * m_{digestate} * (f_{wet} * \frac{k_{wet}}{d_{wet}} + f_{dry} * \frac{k_{dry}}{d_{dry}})$$

$$R_{phosphorous} = r_{phosphorous} * m_{digestate} * (f_{wet} * \frac{k_{wet}}{d_{wet}} + f_{dry} * \frac{k_{dry}}{d_{dry}})$$

$$R_{ammonia} = r_{ammonia} * m_{digestate} * (f_{wet} * \frac{k_{wet}}{d_{wet}} + f_{dry} * \frac{k_{dry}}{d_{dry}})$$

The facility can create an alternative revenue stream by upgrading biogas and selling compressed natural gas. The total revenue (R_{CNG}) is the mass of upgraded biogas (m_{CNG}) multiplied by either the on site or off site sale price (r_{CNG}).

$$R_{CNG} = m_{CNG} * r_{CNG}$$

Economic Calculations

Average Annual Cash Flow

Once the costs for each category are calculated, these costs can be transformed into a number of useful metrics. The most straightforward metric is the annual cash flow of the facility ($\overline{C_{net}}$) at each modeled waste intake level. Each cost category (e.g. facility capital, labor, wastewater) is multiplied by a category- and scenario-specific scalar (S). This scalar is equal to 1 for any costs that are included as calculated, -1 for any revenues, and 0 for costs that are excluded.

$$\bar{C}_{net} = \sum_{i} C_i * S_i$$

For all state specific cost categories i

Net Present Value

NPV of the facility can also be calculated, but temporal factors such as inflation and discounting must be considered. NPV is calculated for a 25-year period, the expected lifetime of the facility capital. Net cash flow ($C_{net,y}$) is calculated for each year of the facility lifetime, then discounted to present worth based on an assumed 7% annual discount rate (r_d). The results for each year are summed to obtain the NPV of the facility (NPV).

Costs are categorized as constant, inflating, or payment for annual net cost calculations. Constant costs appear as the same amount in each year of the NPV analysis whereas inflating increase annually assuming a 2% inflation rate (r_I). In the current model, the constant costs is the rate received for electricity sales, as the facility is currently in a 10-year contract in which the rates do not increase. All other non-capital costs are inflating, such as labor, trucking, and purchased electricity costs.

Capital costs are handled separately, as these costs are paid off according to a depreciation schedule and with payments that include interest considerations, as discussed previously in the payment function. The monthly payment value (PMT_p) and capital lifetime (L_p) of each type of capital are used to determine the cost for each of the 25 years in the NPV analysis ($C_{p,t}$).

$$NPV = \sum_{t=0}^{L_{facility}} \frac{C_{net,y}}{(1+r_d)^t}$$

$$C_{net,y} = \sum_{c}(C_c * S_c) + \sum_{i}(C_i * S_i * (1+r_I)^y) + \sum_{p}\left(PMT_p * 12 * \varphi_{p,y} * S_p\right)$$

For all constant cost categories c, all inflating cost categories i, and all payment cost categories p.

$$\varphi_{p,y} = \max\left(min\left(\frac{L_p}{12} - y, 1\right), 0\right)$$

Internal Rate of Return

The IRR can also be calculated. In cases when the IRR is calculated, the capital sticker price is included as the initial payment (C_0) for the 25 year annual cash flow to serve as the upfront payment.

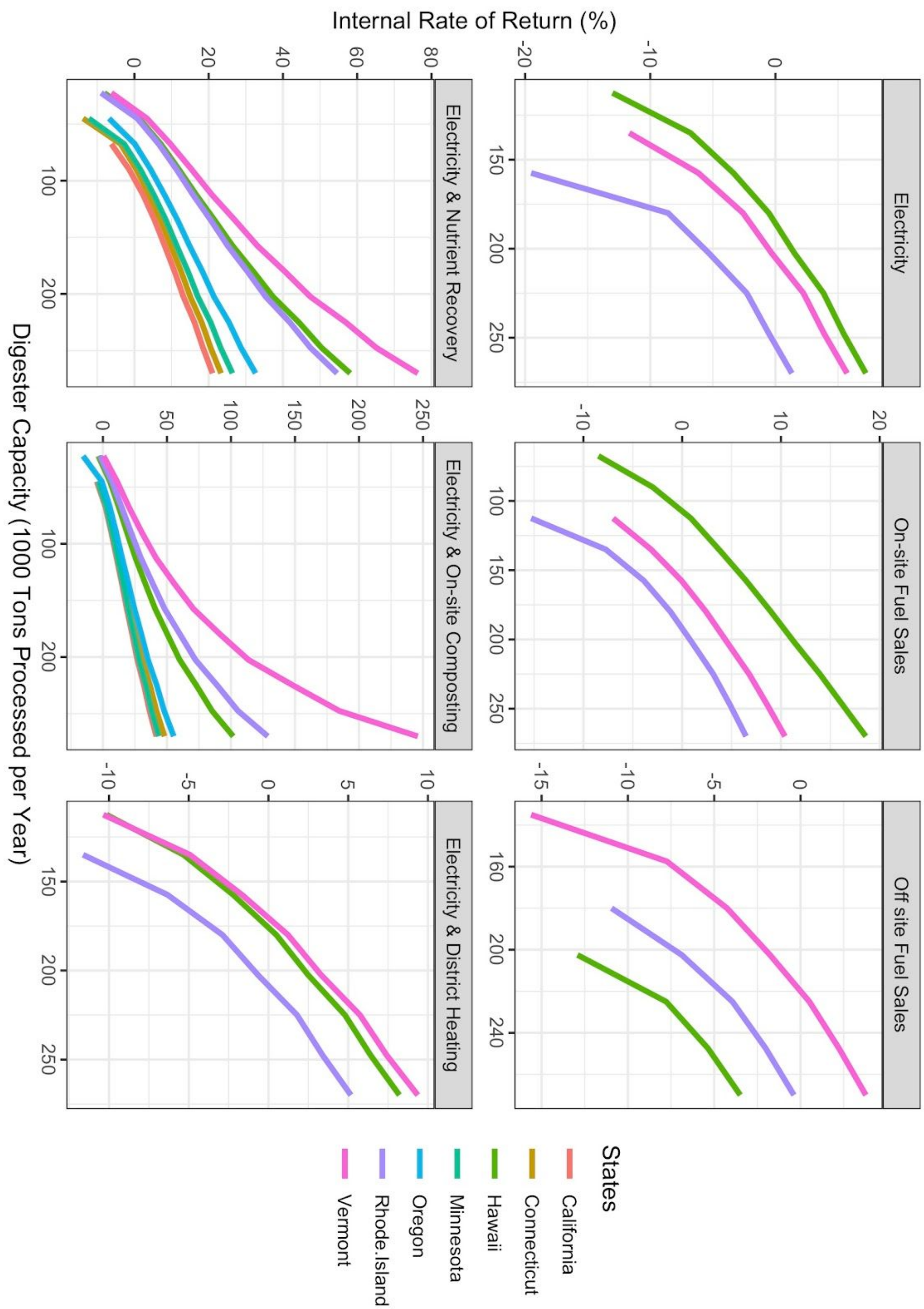
$$\sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_0 = 0$$

Where C_0 is the initial payment, C_t is the yearly payment at year t, T is the facility lifetime, and r is the IRR.

Given the economic assumptions, I assume a threshold of 7 percent as a baseline for facility financial solvency.

Appendix D: Internal Rate of Return Results

Figure 11: Baseline Internal Rate of Return Per Facility Configuration



References

(1) De Baere, L.; Mattheeuws, B. *Anaerobic Digestion of the Organic Fraction of Municipal Solid Waste in Europe*; OWS Inc, 2013.

(2) Linville, J. L.; Shen, Y.; Wu, M. M.; Urgun-Demirtas, M. Current State of Anaerobic Digestion of Organic Wastes in North America. *Current Sustainable/Renewable Energy Reports* **2015**, *2* (4), 136–144.

(3) Satchwell, A. J.; Scown, C. D.; Smith, S. J.; Amirebrahimi, J.; Jin, L.; Kirchstetter, T. W.; Brown, N. J.; Preble, C. V. Accelerating the Deployment of Anaerobic Digestion to Meet Zero Waste Goals. *Environ. Sci. Technol.* **2018**. https://doi.org/10.1021/acs.est.8b04481.

(4) Li, Y.; Jin, Y.; Borrion, A.; Li, H.; Li, J. Effects of Organic Composition on the Anaerobic Biodegradability of Food Waste. *Bioresour. Technol.* **2017**, *243*, 836–845.

(5) Bouallagui, H.; Touhami, Y.; Ben Cheikh, R.; Hamdi, M. Bioreactor Performance in Anaerobic Digestion of Fruit and Vegetable Wastes. *Process Biochem.* **2005**, *40* (3), 989–995.

(6) Munk, B.; Bauer, C.; Gronauer, A.; Lebuhn, M. Population Dynamics of Methanogens during Acidification of Biogas Fermenters Fed with Maize Silage. *Eng. Life Sci.* **2010**, *10* (6), 496–508.

(7) Möller, K.; Müller, T. Effects of Anaerobic Digestion on Digestate Nutrient Availability and Crop Growth: A Review. *Eng. Life Sci.* **2012**, *12* (3), 242–257.

(8) Fantozzi, F.; Buratti, C. Anaerobic Digestion of Mechanically Treated OFMSW: Experimental Data on Biogas/methane Production and Residues Characterization. *Bioresour. Technol.* **2011**, *102* (19), 8885–8892.

(9) Mao, C.; Feng, Y.; Wang, X.; Ren, G. Review on Research Achievements of Biogas from Anaerobic Digestion. *Renewable Sustainable Energy Rev.* **2015**, *45*, 540–555.

(10) *Advancing Sustainable Materials Management: 2015 Fact Sheet*; United States Environmental Protection Agency, 07/2018.

(11) *Inventory of U.S. Greenhouse Gas Emissions and Sinks: Fast Facts*; United States Environmental Protection Agency, 2018.

(12) *The Evolution of Mixed Waste Processing Facilities (1970 - Today)*; {Gershman, Brickner & Bratton, Inc.}, 2015.

(13) *Biogas Potential in the United States*; National Renewable Energy Laboratory, 2013.

(14) FERC: Qualifying Facilities - What is a Qualifying Facility? https://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp (accessed Apr 21, 2019).

(15) FERC: Qualifying Facilities - What Are the Benefits of QF Status? https://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp (accessed Apr 21, 2019).

(16) Martin, S. A. Problems with PURPA: The Need for State Legislation to Encourage Cogeneration and Small Power Production. *BC Envtl. Aff. L. Rev.* **1983**, *11*, 149.

(17) *U.S. District Energy Services Market Characterization*; ICF LLC.

(18) Industry and Market Structure http://naturalgas.org/business/industry/ (accessed Apr 21, 2019).

(19) California Energy Commission. California's Oil Refineries

https://www.energy.ca.gov/almanac/petroleum_data/refineries.html (accessed Apr 21, 2019).
(20) Bacenetti, J.; Negri, M.; Fiala, M.; González-García, S. Anaerobic Digestion of Different Feedstocks: Impact on Energetic and Environmental Balances of Biogas Process. *Sci. Total Environ.* **2013**, *463-464*, 541–551.
(21) Bendixen, H. J. Safeguards against Pathogens in Danish Biogas Plants. *Water Sci. Technol.* **1994**, *30* (12), 171–180.
(22) Lukehurst, C. T.; Frost, P.; Al Seadi, T. Utilisation of Digestate from Biogas Plants as Biofertiliser. *IEA bioenergy* **2010**, *2010*, 1–36.
(23) Nkoa, R. Agricultural Benefits and Environmental Risks of Soil Fertilization with Anaerobic Digestates: A Review. *Agron. Sustain. Dev.* **2014**, *34* (2), 473–492.
(24) Brändli, R. C.; Bucheli, T. D.; Kupper, T.; Furrer, R.; Stahel, W. A.; Stadelmann, F. X.; Tarradellas, J. Organic Pollutants in Compost and Digestate. Part 1. Polychlorinated Biphenyls, Polycyclic Aromatic Hydrocarbons and Molecular Markers. *J. Environ. Monit.* **2007**, *9* (5), 456–464.
(25) Brändli, R. C.; Kupper, T.; Bucheli, T. D.; Zennegg, M.; Huber, S.; Ortelli, D.; Müller, J.; Schaffner, C.; Iozza, S.; Schmid, P.; et al. Organic Pollutants in Compost and Digestate. Part 2. Polychlorinated Dibenzo-P-Dioxins, and -Furans, Dioxin-like Polychlorinated Biphenyls, Brominated Flame Retardants, Perfluorinated Alkyl Substances, Pesticides, and Other Compounds. *J. Environ. Monit.* **2007**, *9* (5), 465–472.
(26) Brenda Platt, Nora Goldstein, Craig Coker, Sally Brown. *The State of Composting in the US*; Institute for Local Self-Reliance, 2014.
(27) Eggerth, L. L. Compost Marketing Trends in the United States. In *The Science of Composting*; de Bertoldi, M., Sequi, P., Lemmes, B., Papi, T., Eds.; Springer Netherlands: Dordrecht, 1996; pp 989–998.
(28) Bustamante, M. A.; Alburquerque, J. A.; Restrepo, A. P.; de la Fuente, C.; Paredes, C.; Moral, R.; Bernal, M. P. Co-Composting of the Solid Fraction of Anaerobic Digestates, to Obtain Added-Value Materials for Use in Agriculture. *Biomass Bioenergy* **2012**, *43*, 26–35.
(29) Bustamante, M. A.; Restrepo, A. P.; Alburquerque, J. A.; Pérez-Murcia; Paredes, C.; Moral, R.; Bernal, M. P. Recycling of Anaerobic Digestates by Composting: Effect of the Bulking Agent Used. *J. Clean. Prod.* **2013**, *47*, 61–69.
(30) Crolla, A.; Kinsley, C.; Pattey, E. 13 - Land Application of Digestate. In *The Biogas Handbook*; Wellinger, A., Murphy, J., Baxter, D., Eds.; Woodhead Publishing, 2013; pp 302–325.
(31) Tambone, F.; Scaglia, B.; D'Imporzano, G.; Schievano, A.; Orzi, V.; Salati, S.; Adani, F. Assessing Amendment and Fertilizing Properties of Digestates from Anaerobic Digestion through a Comparative Study with Digested Sludge and Compost. *Chemosphere* **2010**, *81* (5), 577–583.
(32) Hayk Khachatryan, Ken Casavant, Eric Jessup, Craig Frear. *Economic Feasibility Assessment for Renewable Fertilizers from Anaerobic Digestion with Integrated Manure Nutrient Recovery System*; Freigh Policy Transportation Institute, Washington State University, 2011.
(33) Edwards, J.; Othman, M.; Burn, S. A Review of Policy Drivers and Barriers for the Use of Anaerobic Digestion in Europe, the United States and Australia. *Renewable Sustainable Energy Rev.* **2015**, *52*, 815–828.
(34) Industry Builds the Future of Recycling Amid China Ban Woes

https://www.waste360.com/business/industry-builds-future-recycling-amid-china-ban-woes (accessed Apr 22, 2019).
(35) *Disposal Bans & Mandatory Recycling in the United States*; Northeast Recycling Council, 2017.
(36) Kang, D. H. P.; Chen, M.; Ogunseitan, O. A. Potential Environmental and Human Health Impacts of Rechargeable Lithium Batteries in Electronic Waste. *Environ. Sci. Technol.* **2013**, *47* (10), 5495–5503.
(37) State of California. Statewide Average Monthly Scrap Value Notice https://www.calrecycle.ca.gov/bevcontainer/scrapvalue (accessed Apr 22, 2019).
(38) Powell, J. *2018 Recycling Market Update*; Resource Recycling, 2018.
(39) Themelis, N. J.; Ulloa, P. A. Methane Generation in Landfills. *Renewable Energy* **2007**, *32* (7), 1243–1257.
(40) State Waste & Recycling Laws | RIRRC https://www.rirrc.org/about/state-waste-recycling-laws (accessed Apr 22, 2019).
(41) Fresh Look At Organics Bans And Waste Recycling Laws - BioCycle https://www.biocycle.net/2016/11/10/fresh-look-organics-bans-waste-recycling-laws/ (accessed Apr 22, 2019).
(42) Geise, H. A Growing List of Food Waste Bans Across America http://blog.spoileralert.com/food-waste-bans (accessed Apr 23, 2019).
(43) EPA releases final list of counties that do not meet federal air quality standards for Ozone https://www.naco.org/blog/epa-releases-final-list-counties-do-not-meet-federal-air-quality-standards-ozone (accessed Apr 23, 2019).
(44) Epa, U. S.; OAR. Reviewing National Ambient Air Quality Standards (NAAQS): Scientific and Technical Information. **2016**.
(45) Couture, T. D.; Cory, K.; Kreycik, C.; Williams, E. *Policymaker's Guide to Feed-in Tariff Policy Design*; National Renewable Energy Lab.(NREL), Golden, CO (United States), 2010.
(46) Couture, T.; Gagnon, Y. An Analysis of Feed-in Tariff Remuneration Models: Implications for Renewable Energy Investment. *Energy Policy* **2010**, *38* (2), 955–965.
(47) *Side-by-Side of State Feed-In Tariff Programs*; State of Maine Office of Policy and Legal Analysis.
(48) Van der Linden, N. H.; Uyterlinde, M. A.; Vrolijk, C.; Nilsson, L. J.; Khan, J.; Åstrand, K.; Ericsson, K.; Wiser, R. Review of International Experience with Renewable Energy Obligation Support Mechanisms. *Energy Research Centre of the Netherlands. ECN-C--05-025* **2005**.
(49) Couture, T.; Cory, K. S. *State Clean Energy Policies Analysis (SCEPA) Project: An Analysis of Renewable Energy Feed-in Tariffs in the United States*; National Renewable Energy Laboratory Golden, CO, 2009.
(50) Mintz, M., P. Voss, M. Tomich, and A. Blumenthal. Database of Renewable Natural Gas (RNG) Projects.
(51) *Renewable Natural Gas: Monetary Incentive Program for Biomethane Projects: Pipeline Infrastructure*.
(52) Lucas, J. Utility Interconnection. Power of Waste: Renewable Natural Gas (RNG) for California Workshop, 2016.
(53) Pipeline Injection Of Biomethane In California - BioCycle https://www.biocycle.net/2018/03/12/pipeline-injection-biomethane-california/ (accessed

Apr 23, 2019).
(54) Epa, U. S.; OAR. RIN Trades and Price Information. **2018**.
(55) Schnepf, R.; Yacobucci, B. D. Renewable Fuel Standard (RFS): Overview and Issues; Library of Congress, Congressional Research Service, 2013.
(56) Representative, C. .
(57) California Air Resources Board. LCFS Basics https://www.arb.ca.gov/fuels/lcfs/background/basics.htm (accessed Apr 23, 2019).
(58) Pavlenko, N.; Searle, S.; Malins, C.; El Takriti, S. Development and Analysis of a Durable Low Carbon Fuel Investment Policy for California. *October. White Paper. ICCT. http://www. theicct. org/sites/default/files/publications/California% 20Contracts% 20for% 20Dif ference_white-paper_ICCT_102016. pdf* **2016**.
(59) United States Department of Agriculture. National Agricultural Statistics Service Database.
(60) Center for Food Safety; Nutrition, A. Food Safety Modernization Act (FSMA) - Federal/State Integration.
(61) U.S. Energy Information Administration (EIA). Wholesale Electricity and Natural Gas Market Data.
(62) Li, H.; Sun, Q.; Zhang, Q.; Wallin, F. A Review of the Pricing Mechanisms for District Heating Systems. *Renewable Sustainable Energy Rev.* **2015**, *42*, 56–65.
(63) Gudmundsson, O.; Thorsen, J. E.; Zhang, L. Cost Analysis of District Heating Compared to Its Competing Technologies. *WIT Trans. Ecol. Environ.* **2013**, *176*, 3–13.
(64) Xebec Adsorption Inc. Xebec to deliver biogas upgrading plant for RNG project in Italy http://biomassmagazine.com/articles/16024/xebec-to-deliver-biogas-upgrading-plant-for-rng-project-in-italy (accessed Apr 25, 2019).
(65) Margaret Smith, J. G. *Costs Associated With Compressed Natural Gas Vehicle Fueling Infrastructure*; US Department of Energy, 2014.
(66) Lucas, J. Gas to Grid Interconnection, 2016.
(67) Bryan F Staley, Debra L Kanter, Joshua Choi. *Analysis of MSW Landfill Tipping Fees: April 2018*; The Environmental Research and Education Foundation (EREF), 2018.
(68) Home http://rrdd1.com/feeSchedule.html.
(69) DSM Environmental Services, Inc. *The Price of Solid Waste Management Services in Vermont*; Vermont Department of Environmental Conservation , 2005.
(70) Pricing | Cold Creek Compost http://www.coldcreekcompost.com/pricing/ (accessed Apr 27, 2019).
(71) Topsoil, Compost, Eco Soil, & Fill https://www.grilloservices.com/topsoil-and-compost-ct/ (accessed Apr 27, 2019).
(72) Organic Soil + Compost | Hawaiian Earth Recycling https://hawaiianearth.com/compost-soil-prices (accessed Apr 27, 2019).
(73) Products – Southern Oregon Compost http://southernoregoncompost.com/products/ (accessed Apr 27, 2019).
(74) Bulk Archives - Green Mountain Compost https://www.greenmountaincompost.com/product-category/bulk/ (accessed Apr 27, 2019).
(75) The Compost PlantThe Compost Plant http://www.compostplant.com/ (accessed Apr 27, 2019).
(76) U.S. Energy Information Administration. U.S. Natural Gas Prices.

(77) Moselle, B. *2019 National Building Cost Manual*; Craftman.
(78) U.S. Bureau of Labor Statistics. Occupational Employment Statistics, 2017.
(79) *Funding On-Farm Anaerobic Digestion*; United States Environmental Protection Agency, AgSTAR Program, 2012.
(80) California Air Resources Board. The LCFS Credit Price Calculator, 2018.
(81) Wu, B.; Zhang, X.; Xu, Y.; Bao, D.; Zhang, S. Assessment of the Energy Consumption of the Biogas Upgrading Process with Pressure Swing Adsorption Using Novel Adsorbents. *J. Clean. Prod.* **2015**, *101*, 251–261.
(82) Sanscartier, D.; Maclean, H. L.; Saville, B. Electricity Production from Anaerobic Digestion of Household Organic Waste in Ontario: Techno-Economic and GHG Emission Analyses. *Environ. Sci. Technol.* **2012**, *46* (2), 1233–1242.