CASE STUDIES

MAY 2023

The project economics of producing renewable natural gas or electricity and the impact of policy incentives

Introduction

Under California's Short-Lived Climate Pollutant (SLCP) reduction strategy, biomethane producers are required to take preventative measures to reduce the quantity of methane vented to the atmosphere. Because biomethane and its intermediate, biogas, are intrinsic waste products of farming, landfilling, and organic waste operations, producers must either implement control measures to limit its production or capture gas at the source and utilize it in alternative applications. Biogas has economic value and is eligible for significant policy incentives within the state of California; these policies have created an economic environment that is attractive for producers to utilize biomethane as an energy source.

We provide three case studies to illustrate the project economics that biogas producers may consider when upgrading biogas to biomethane to be sold on the market. Each case study compares the cost of utilizing biomethane in three end-use applications: 1) converting biomethane to electricity and delivering it to the power sector, 2) converting biomethane to electricity and claiming the energy units for the transport sector, and 3) converting biomethane to renewable natural gas (RNG) that is injected to the natural gas pipeline distribution network. The case studies include one out-of-state digester project, one large landfill gas project, and one small farm cluster that currently treats manure using pasture management. This analysis is conducted to provide insight into the costs of producing RNG or electricity across project types and to compare the impact of policy incentives on the cost effectiveness of different end-use applications.

Methodology

We conduct a discounted cash flow analysis for nine project scenarios that is consistent with the methodology presented in O'Malley et al. (2023). A matrix of these scenarios is presented in Table 1.

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Table 1. Summary of case study scenarios.

Project type		Landfill gas	Small farm cluster	Out-of-state digester
Application	Renewable natural gas	Case study 1a	Case study 2a	Case study 3a
	Grid electricity	Case study 1b	Case study 2b	Case study 3b
	Low carbon-intensity electricity	Case study 1c	Case study 2c	Case study 3c

For project developers to make the business case to upgrade biomethane into electricity or RNG, we assume that projects must both be cost effective—that is generate a positive net present value (NPV) over a 10-year crediting period—and geographically suitable to connect to the regional natural gas transmission pipeline network. We summarize our methodology for our spatial and cash flow analyses below.

Spatial analysis

We utilize the software QGIS to conduct a spatial analysis for each case study. For each potential project, the distance between the biomethane source and the nearest natural gas pipeline is measured using geographic information system (GIS) mapping. A polyline dataset containing the U.S. natural gas pipeline network is retrieved from the Homeland Infrastructure Foundation-Level Data (HIFLD) dataset (U.S. Department of Homeland Security, n.d.). This dataset collects spatial data on all major natural gas transmissions pipelines in the United States. The U.S Electric Power Transmission Lines dataset (Esri, n.d.) is also used to determine whether there are any underground electric transmission lines that may obstruct natural gas pipeline connections. No underground transmission lines are found in proximity to the three case studies, so these polylines are omitted from final maps. Google Earth satellite data is also used to determine whether there are any additional infrastructure constraints that may prevent a direct low-pressure pipeline connection to the central grid.

Cash flow analysis

After finding the necessary datapoints from the spatial analysis, we conduct a discounted cash flow analysis to calculate a 10-year project net present value (NPV) for each case study, pursuant with the methodology for our breakeven cost analysis (O'Malley, et al., 2023).

In total, we develop three scenarios that capture the likely applications of biomethane generated at each facility: 1) biomethane upgraded to RNG fuel, 2) biomethane burned as electricity and sold to the regional electric grid, and 2) biomethane burned as electricity and sold as a low-carbon transportation fuel via book-and-claim accounting. Each scenario is applied to our three case studies to compare NPVs before and after the implementation of California's methane reduction regulation (i.e., Senate Bill 1383) in 2024. This regulation is expected to change the operating baseline and revenue streams from affiliated policies. We assume that Low Carbon Fuel Standard (LCFS) and RIN credit price data remains constant over the entirety of the project lifetime; credit prices fluctuate with market conditions and policy targets, but these changes are not expected to significantly alter overall outcomes.

All formulas and input data described in O'Mallley et al. (2023) are the same in this analysis; however, we include additional data for biogas that is converted to electricity and used in the power or transportation sectors. Capital and operating costs for electricity generators and microturbines are sourced from Appendix F of the SLCP strategy document and the LFG Energy Project Development Handbook for dairy manure and landfill gas projects, respectively (California Air Resources Board, 2017; U.S. Environmental Protection Agency, 2016).

Revenue streams for electricity pathways include the wholesale price of electricity, cap and trade offsets for dairy digester projects, a biomethane feed-in-tariff credit for projects less than 5 MW, and LCFS credits for low carbon-intensity (CI) electricity claimed by battery electric vehicles. All revenue streams remain constant apart from cap-and-trade offsets, which are a function of baseline manure management assumptions. Biomethane sold as electricity is not yet eligible to receive RIN credits since the Renewable Fuel Standard (RFS) program currently only recognizes liquid or gaseous biomass-based fuel pathways. The proposed implementation of the RFS e-RIN pathway could provide additional revenue for biomethane burned as electricity when its energy value is claimed by the transportation sector (U.S. Environmental Protection Agency, 2022).

Case Study 1: Frank R. Bowerman Landfill

The Frank R. Bowerman Landfill is permitted to collect 11,500 tons of waste per day, making it one of the largest landfills operating in California and ninth largest in country. Since 2016, the facility has captured landfill gas to generate electricity at a 20 MW electric generator. On average, this landfill gas (LFG) project produces 160,000 MWh of power each year and powers close to 15,000 homes (Chay, 2016). The facility has an average LFG flow rate of 10.75 million standard cubic feet per day.

The Bowerman landfill is a suitable project for biomethane pipeline injection due to its large size and highly close proximity (46 meters) to the natural gas grid network.

Figure 1 displays a possible low-pressure pipeline connection route to the existing transmission line, which was determined using satellite data. We do not identify any other infrastructure components that would obstruct a direct pipeline connection.

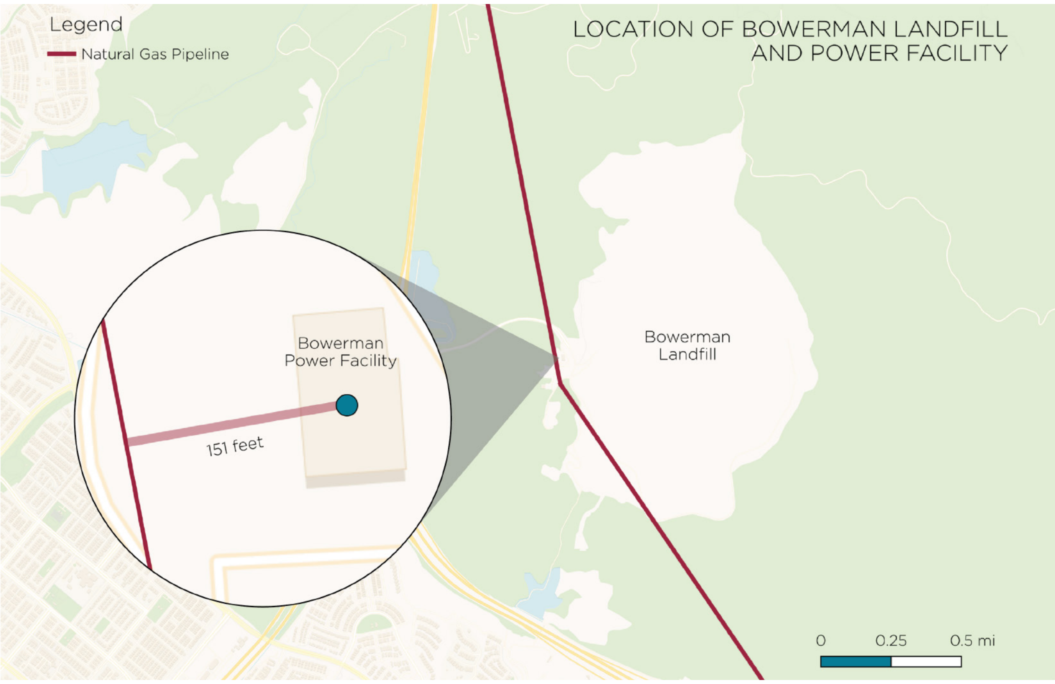

Figure 1. Satellite imagery of a potential Bowerman landfill pipeline connection route.

Case study 1a: RNG

At a CI value of 45.05 gCO_2e/MJ, we calculate annual LCFS credit prices ranging between $3.73 and 4.92 per million British thermal units (MMBTU) of RNG. We assume an RNG fuel sale price of $3.46 per thousand cubic feet of biogas and RIN credit price of $2.65 per 77,000 BTU of RNG generated. Assuming a 91% project uptime and feed losses from GREET, we calculate an annual biomethane production rate of 2.3 trillion BTUs.

Because of the project's exceedingly high annual flow rate and favorable LCFS and RIN credit values, we calculate a 10-year NPV of $537 million for a large landfill gas project upgrading biomethane to RNG sold in the California market**.** RNG produced from this pathway has an average value of $45/MMBTU.

Case study 1b: Grid electricity

For electricity pathways, we input the same project flow rate assumptions into LFG energy cost model formulas. The only revenue stream for this bio-electricity pathway is the wholesale cost of electricity in the California Independent System Operator market. Projects less than 5 MW in size receive an additional $0.1277/kWh renewable electricity feed-in tariff (Pacific Gas and Electric Company, n.d.). Since the Bowerman landfill is already equipped with an electric generation unit, we assume a capital cost of zero for this project.

Despite having no additional capital costs, the 10-year NPV for maintaining the current project configuration is one-eighth of the RNG utilization scenario, or approximately $66 million. This indicates that electricity generation is significantly less profitable than RNG production for landfill gas projects in the current policy landscape.

Case study 1c: Low-CI electricity

A third scenario for landfill gas projects that assumes electricity sold to the regional grid is credited via the low-CI electricity pathway under the LCFS (CARB, 2019). Capital and operating costs remain the same as the conventional electricity pathways, but the project is eligible to receive LCFS credits. We update the CI value to represent GHG emissions per unit of electrical energy when landfill gas is burned as electricity at a 33% energy conversion rate. We estimate a CI value of 9.71 gCO_2e/MJ, which corresponds to annual LCFS credit values ranging between $0.025 and $0.030 per kWh of electricity.

In summary, we find that the Bowerman landfill is much more profitable as a source of RNG than as a source of electricity. Ten-year project NPVs in millions of USD are shown for each end-use application in Figure 2. Cost are calculated with and without avoided methane crediting for each scenario. However, the site is currently in a contract with the local electric utility to purchase its power, so the project will continue to operate as an electricity source over the next 10 years.

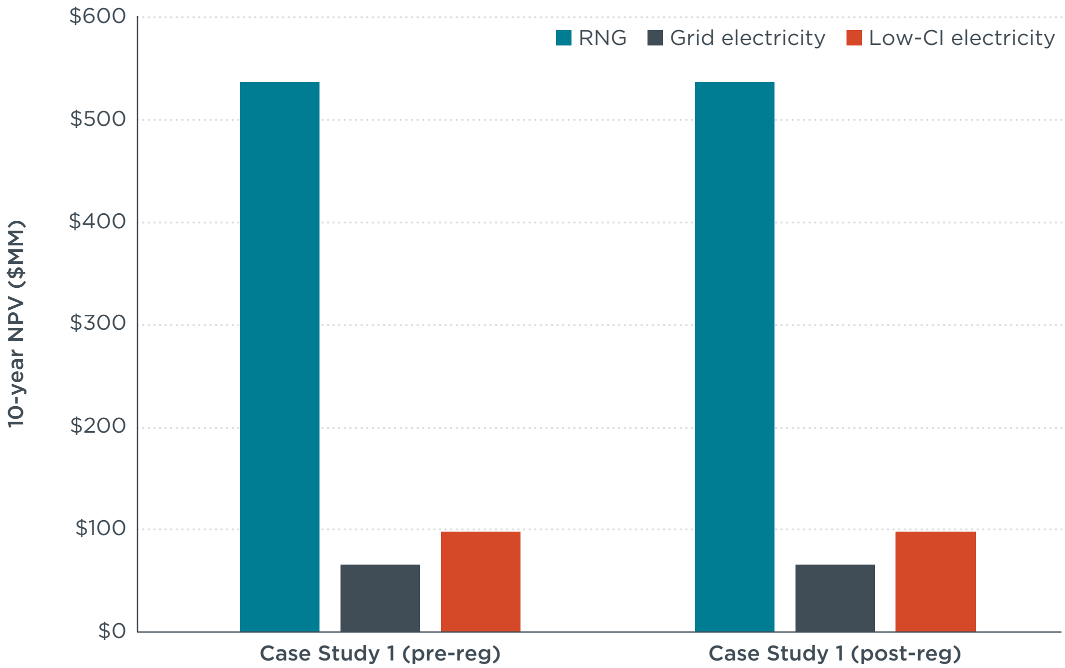

Figure 2. NPV comparison for Bowerman landfill across three end-use scenarios

Case Study 2: Clover Sonoma farms

Clover Sonoma operates 26 farms in Central California, located across Sonoma, Marin, and Mendocino counties. The company utilizes organic manure treatment strategies at all farms and applies manure as fertilizer rather than utilizing commercial treatment strategies such as lagoons or pit storage. This family of farms could be suitable for a dairy digester cluster project and would be eligible for significant grant funding from both the federal government and state of California.

Figure 3 shows a schematic of Clover Sonoma farm locations overlayed with the HIFLD natural gas transmission pipeline network. Spatial analysis reveals that a cluster of 23 Clover Sonoma farms are located near the Western coast in Sonoma and Marin Counties. Three farms located on the periphery of the cluster (Vevoda Dairy, Garcia Dairy, and Double D Dairy #2) are excluded from our analysis due to their prohibitive distance from the central cluster of farms.

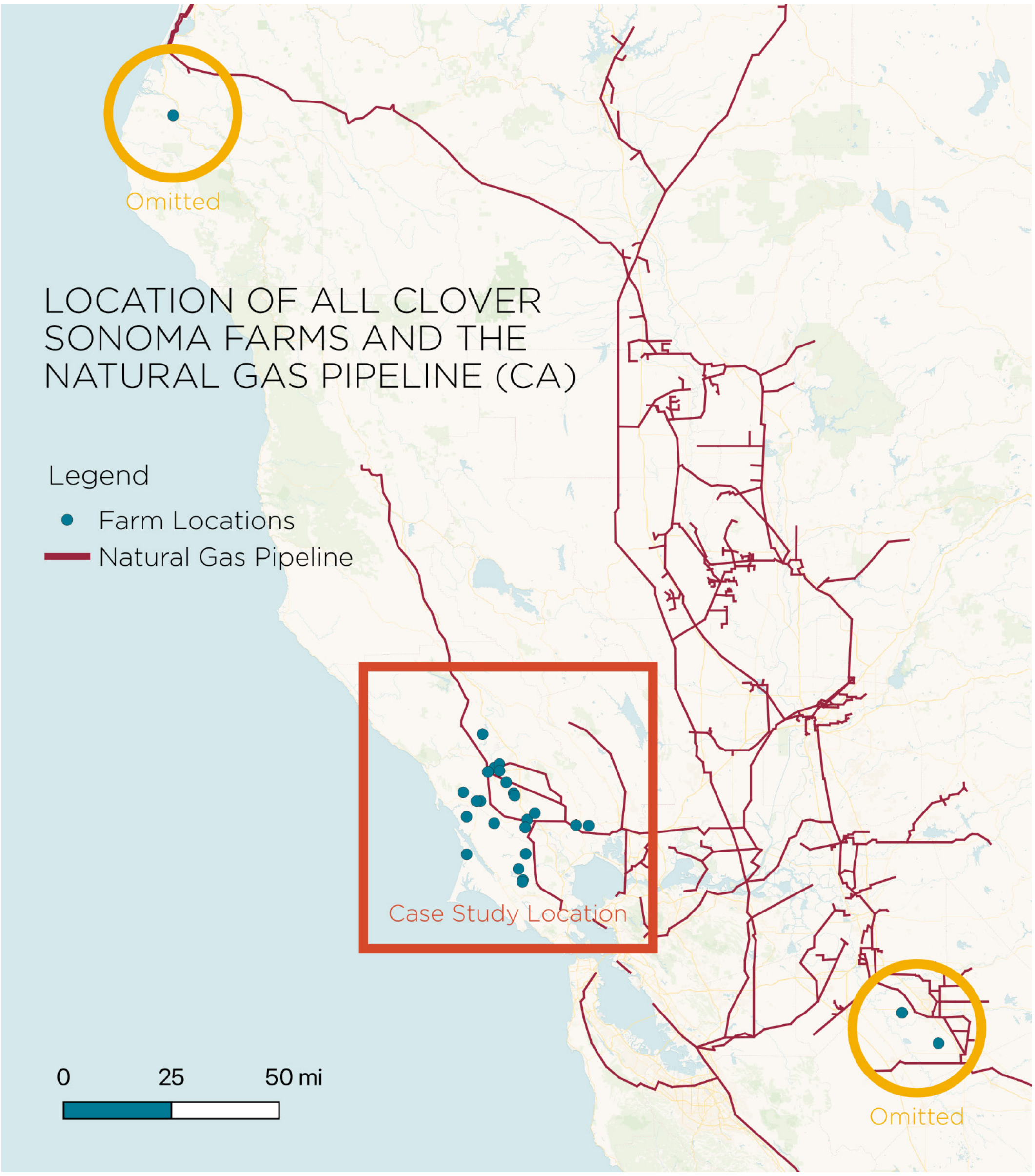

Figure 3. Location of Clover Sonoma farms relative to natural gas transmission line

We use a "hub and spoke" model to determine the optimal location for a potential dairy biogas cluster project within Clover Sonoma farms. Using this methodology, a single "hub" is designated to place the central digester to later upgrade biomethane for pipeline injection. Manure generated at other locations, or "spokes," is delivered to the central digester. Several digester projects located in California, such as the Kern County cluster, utilize the hub and spoke model to offset project costs for upgrading biomethane to RNG (Black, 2019).

We measure the direct distance from each Clover Sonoma farm to the transmission pipeline network to be between .06 and 6.14 miles, with the closest location being Buttke Dairy located near Sebastopol. We determine the central farm by calculating the annual pipeline and trucking costs for each project location and selecting the site with the lowest overall costs.

To conduct the cost analysis, the number of dairy cows is used to derive the amount of manure produced by each farm. The number of cows is found from project documentation on the Clover Sonoma website (Clover Sonoma, n.d.); total head counts ranged from 155 to 850 heads. In cases where individual farms did not publish a head count, the average number of cows across the cluster (approximately 380) is used. Table 2 lists each farm's dairy cattle head count, size in acres, and distance to the state's natural gas pipeline network.

Table 2. Characteristics of Clover Sonoma farms

Name	Size (acres)	Number of cows	Manure (lbs.)	Distance to natural gas transmission pipeline (mi)
Aggio Dairy Inc.	N/A	380 (est.)	53,200	0.41
Amos Brothers Dairy	N/A	380 (est.)	53,200	0.74
Beretta Family Dairy	400	300	42,000	0.40
Bucher Farms	2,000	700	98,000	2.88
Buttke Dairy	750	155	21,700	0.06
Dolcini Jersey Dairy	585	380 (est.)	53,200	3.71
Gerald Spaletta Dairy	350	400	56,000	1.77
Ielmorini Dairy	1,160	200	28,000	3.02
Ielmorini Moody Dairy	N/A	380 (est.)	53,200	3.08
Jim Riebli Dairy	200	180	25,200	0.27
Joe Pinheiro Dairy	150	400	56,000	0.73
Johnson-Neles Dairy	380	380 (est.)	53,200	0.60
Kehoe Dairy	160	380 (est.)	53,200	12..45
Lafranchi Dairy	1,150	380 (est.)	53,200	3.20
Moretti Family Dairy	300	250	35,000	6.14
Morrison Bros. Dairy	N/A	380 (est.)	53,200	2.05
Mulas Dairy	N/A	850	119,000	1.69
N. Mcisaac and Son	250	450	63,000	2.77
Perucchi Dairy	450	380 (est.)	53,200	5.94
Renati Dairy	N/A	380 (est.)	53,200	2.18
Roy King Dairy	N/A	380 (est.)	53,200	1.49
Spaletta Ranch	772	300	42,000	1.91
Terrilinda Dairy	N/A	380 (est.)	53,200	2.48

The trucking distance from each farm to the designated hub is calculated for the optimization analysis. The trucking distance is found by using the closest driving distance as defined using Google Maps.

To designate a single hub to build the central dairy digester, a simple cost calculation is conducted prior to conducting the cash flow analysis. By adding the pipeline cost, pipeline operation and maintenance cost, trucking cost, and labor cost for 1 year of operation for each dairy farm, we find that Buttke Dairy has the lowest costs when chosen as the central hub. Hence, we conduct our cash flow analysis using Buttke Dairy as the digester location for Case Study 2.

Case study 2a: RNG

At a CI value of 41.12 gCO_2e/MJ, we calculate annual LCFS credit prices ranging between $4.14 and 5.33 per MMBTU of RNG. We assume an RNG fuel sale price of $3.46 per thousand cubic feet of biogas and a RIN credit price of $2.65 per 77,000 BTU of RNG generated. Assuming that RNG is recycled to heat the digesters and upgrading system, and applying feed losses from GREET, we calculate an annual biomethane production rate of 41.4 billion BTUs.

Cluster projects benefit from economies of scale but are subject to significant trucking and labor costs to pool together manure resources. These projects also have significant capital and operational costs to support the construction of a new anaerobic digester. We find that revenue streams do not outweigh annual production costs and calculate a 10-year NPV of -$13.9 million for the Clover Sonoma cluster project. RNG produced from this pathway has an average value of $46/MMBTU.

Case study 2b: Grid electricity

Our cluster project is smaller than 5 MW in size, so it is eligible for Pacific Gas & Electric's biomethane feed-in tariff. This project is also eligible for cap-and-trade offset credits, in accordance with the compliance offset protocol for livestock projects (California Air Resources Board, 2014). We assume a constant cap-and-trade credit price of $25 per metric tonne of CO_2e avoided. This value is both near the current trading price and credit floor price in 2030 (California Air Resources Board, 2017).

Forming a dairy cluster project that sources manure from small organic farms would require constructing an anaerobic digester and a costly microturbine to comply with local regulations. Total capital costs for this project are $16 million; operational costs are also high due to trucking and labor costs for pooling manure. We calculate a 10-year NPV of -$21 million**,** slightly costlier than the RNG pathway.

Case study 2c: Low-CI electricity

The third scenario that assumes electricity generated from the dairy cluster project is sold to the regional grid and credited via the low-CI electricity pathway under the LCFS. Capital and operating costs remain the same as the grid electricity pathway, but revenue streams from cap-and-trade and the biomethane feed-in tariff are replaced with an LCFS credit revenue stream from low-CI electricity.

We use the Tier 1 calculators to update the CI value to represent GHG emissions per unit of electrical energy when dairy biogas gas is burned as electricity at a 33% energy conversion rate. We estimate a CI value of 29.48 gCO_2e/MJ, which corresponds to annual LCFS credit values ranging between $0.018 and $0.022 per kWh of electricity.

In summary, we find that the Clover Sonoma farm cluster results in a negative 10-year NPV in all end-use cases, with the least profitable application being electricity claimed by battery electric vehicles (Figure 4). Because the project herd size is smaller than our calculated breakeven threshold, its annual production costs exceed its annual revenue.

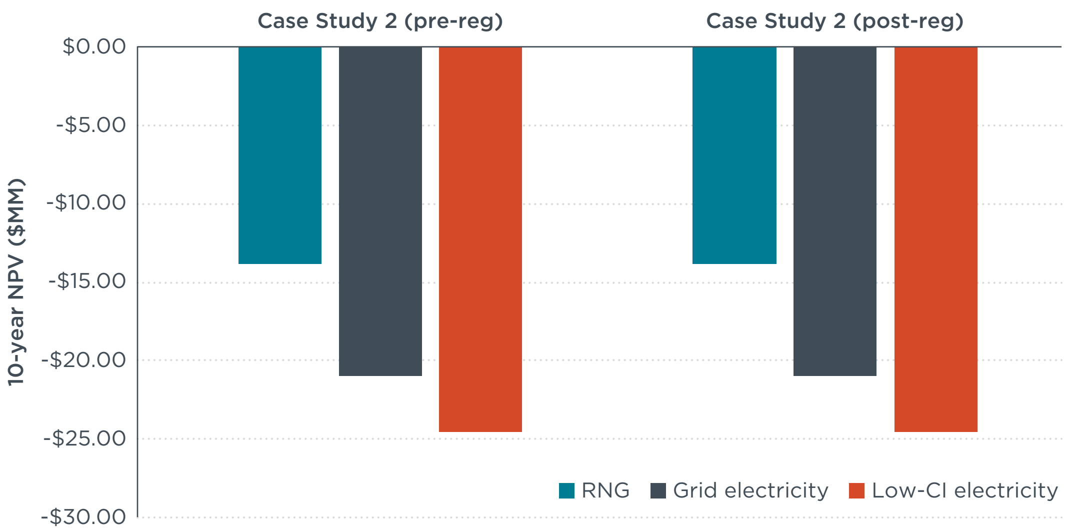

Figure 4. NPV comparison for Clover Sonoma farm project across three end-use scenarios

Case Study 3: Five Star Dairy farm

The Five Star Dairy in Wisconsin is selected as an out-of-state case study that qualifies for LCFS credits among dairy digesters listed on the Environmental Protection Agency (EPA) AgSTAR dataset (U.S. EPA, n.d.). This is a medium-sized farm with 1,100 cows that upgrades biogas to electricity that is delivered to a local electric cooperative. The digester generates 775 kW of electricity that can power 600 households (Farm Energy, 2009). Five Star Dairy is one of seventeen projects located in Wisconsin that generate LCFS credits via book-and-claim accounting; this case study serves as an illustrative example of an out-of-state farm that may pursue biomethane upgrading for LCFS crediting.

We use the same method as the Bowerman Power Facility to map the distance from the farm to the gas transmission pipeline. The distance between the farm and pipeline is approximately 5.45 miles, shown in Figure 5.

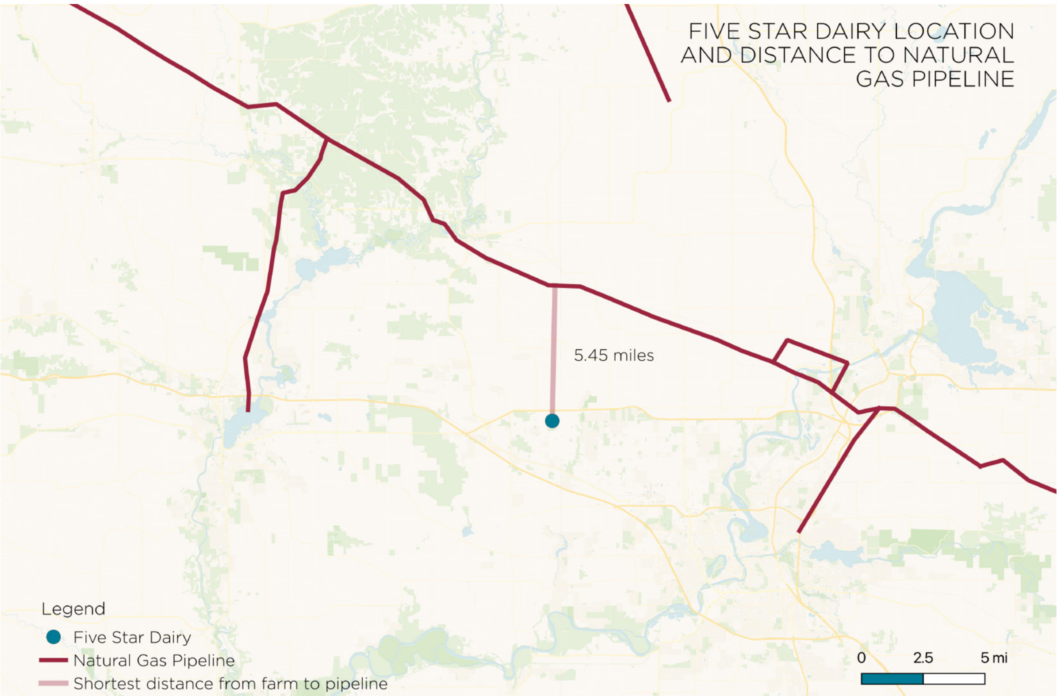

Figure 5. Distance between Five Star Dairy farm and natural gas distribution pipeline

Case study 3a: RNG

Our third case study is an out-of-state digester project, so it is subject to different grid electricity and methane generation emission factors than our previous two examples. We input the corresponding electricity grid and methane generation factors for Wisconsin cattle into the Tier 1 calculators and calculate a CI of -411.08 gCO_2e/MJ for the pre-regulatory scenario. We remove avoided methane emissions and calculate a CI of 46.58 for the post-regulatory scenario.

We calculate annual LCFS credit prices ranging between $51.85 and $53.04 per MMBTU of RNG for the pre-regulatory scenario and credit prices ranging between $3.57 and $4.76 per MMBTU for the post-regulatory scenario. We assume an RNG fuel sale price of $3.46 per thousand cubic feet of biogas and RIN credit price of $2.65 per 77,000 BTU of RNG generated. This project is located more than 5 miles from the closest natural gas transmission line, so it has significant interconnection fees and pipeline infrastructure costs.

Capital and operating costs outweigh annual revenue for both the pre- and post-regulatory scenarios. We calculate a 10-year NPV of -$1.88 and -$3.54 million for the pre- and post-regulatory scenarios, respectively.

Case study 3b: Grid electricity

Five Star Dairy is an existing dairy digester project located outside of California so it not eligible for Pacific Gas & Electric's biomethane feed-in tariff. Xcel Energy, a nearby utility serving the region, offers a biomass-based electricity incentive of $0.07 per kWh which we include as a revenue stream. We also assume the project remains eligible for livestock manure electricity offset credits (Institute for Local Self-Reliance, 2010). Five Star Dairy is already generating electricity sold to the regional utility, so this scenario is reflective of current operating conditions. Likewise, it is not subject to additional capital costs or interconnection fees.

Because the project does not generate LCFS credits in this scenario, its pre-and post-regulatory NPVs are the same. We calculate a 10-year NPV of $0.08 million for maintaining biomethane in its current use for a mid-sized out-of-state dairy farm.

Case study 3c: Low-CI electricity

The final scenario assumes electricity sold to the regional grid is credited as low-CI electricity under the LCFS. Rather than consumed by the power sector, this electricity is now attributed toward the transport sector via book-and-claim accounting. We calculate a CI of -604.37 gCO_2e/MJ in the pre-regulatory case and 20.02 gCO_2e/MJ in the post-regulatory case, assuming a 33% electrical conversion efficiency and the same regional emission factors as outlined above.

For this case study, it is more profitable to credit electricity under transport sector programs than to sell it as excess power to the regional electricity grid in a pre-regulatory environment (Figure 6). If avoided methane emissions are removed from CI calculations once SB1383 takes effect, the reverse is true. Assumptions around baseline operating conditions have a significant impact on annual revenue for this existing out-of-state dairy digester project.

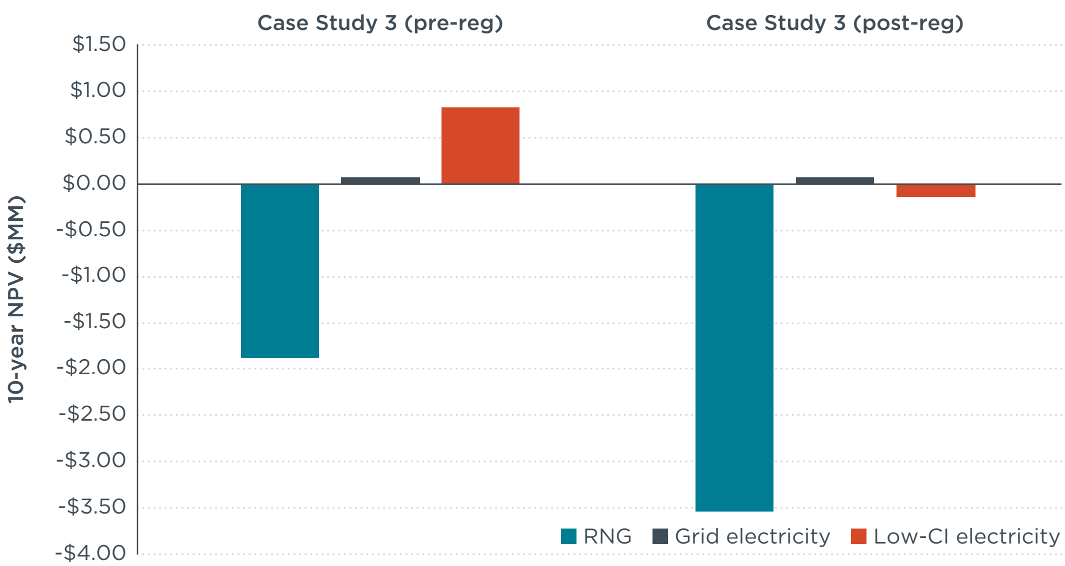

Figure 6. NPV comparison for Five Star Dairy digester project across three end-use scenarios

Summary of results

We summarize capital costs, operating costs, revenue, and 10-year project NPVs with and without avoided methane crediting in Table 3. The value of biomethane, calculated as the quantity of revenue per unit energy produced, ranges between $5.50 per MMBTU for landfill gas to electricity projects and $93.32 per MMBTU for dairy derived biomethane that is upgraded to RNG.

Table 3. Project cost components and NPVs for nine biomethane end-use scenarios.

Million USD	CAPEX	OPEX	Revenue (pre-reg)	Revenue (post-reg)	NPV (pre-reg)	NPV (post-reg)
Case Study 1 (electricity, power)	$0.00	$2.74	$12.75	$12.75	$66	$66
Case Study 1 (RNG, pipeline)	$56.8	$13.99	$104.66	$104.66	$537	$537
Case Study 1 (electricity, EV)	$0.0	$2.74	$56.77	$56.77	$97.7	$97.7
Case Study 2 (electricity, power)	$19.0	$1.22	$1.49	$1.49	-$21.0	-$21.0
Case Study 2 (RNG, pipeline)	$16.0	$0.9	$1.89	$1.89	-$13.9	-$13.9
Case Study 2 (electricity, EV)	$19.0	$1.2	$0.97	$0.97	-$24.5	-$24.5
Case Study 3 (electricity, power)	$0.00	$0.28	$0.30	$0.30	$0.079	$0.079
Case Study 3 (RNG, pipeline)	$3.1	$0.33	$0.49	$0.23	-$1.88	-$3.54
Case Study 3 (electricity, EV)	$0.00	$0.28	$0.41	$0.27	$0.83	-$0.143

As shown, the implementation of SB 1383 only has an impact on revenue for the out-of-state digester project (Case Study 3). Case Studies 1 and 2 do not qualify for avoided methane crediting or cap-and-trade offsets that may be affected upon implementation of SB 1383 in 2024.

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