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Energy Systems Analysis Framework for the Decarbonization of Industrial Process Heat

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Abstract

Transitioning energy systems from a reliance on fossil fuels to low carbon energy sources is an essential solution for climate change mitigation. However, the industrial sector, which is directly responsible for more than a quarter of global carbon dioxide (CO_2) emissions, continues to use fossil fuels for energy and feedstocks. Industry has been slow to decarbonize because it faces many unique challenges: a diverse set of industrial processes with different energy demands and technologies, high-cost equipment with long lifetimes, and competitive international markets for its products. One cross-cutting opportunity for emissions abatement in industry is decarbonizing industrial process heat. Many low carbon technology pathways have been analyzed for industrial heat decarbonization, but the lack of bottom-up process modeling in technology assessments and scarcity of industrial facility- and unit-level data remain challenges.

In this dissertation, an energy systems analysis framework for evaluating low carbon process heat technologies is developed. The first portion of this dissertation focuses on solar thermal and electric process heat technologies, applications, and technical and economic potential modeling for the U.S. manufacturing sector. Stemming from this research, the electrification of industrial boilers is analyzed in greater detail, and an industrial boiler dataset characterizing the stock of conventional industrial boilers in the United States is developed. The next portion of the dissertation explores sources of industrial data, their limitations, and new ways to capture data on unit types, material throughput, and unit energy use. The final study applies the framework in two chemicals manufacturing industries to compare emissions impacts and lifetime costs of electrification and hydrogen technologies with conventional process heat technologies. Collectively, this research can be applied in future analyses and used to inform policy on industrial process heat decarbonization.

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1. Introduction

1.1 Impacts of Industrial Energy Use and Emissions on Climate Change

Climate change mitigation is one of the most pressing global challenges of the 21st century, and its urgency calls for solutions that can significantly reduce anthropogenic greenhouse gas emissions (GHG) in the next several decades. Transitioning energy systems from a reliance on fossil fuels to low carbon energy sources is an essential solution for reducing these emissions. Currently, a quarter of global carbon dioxide emissions (9.2 $GtCO_2$ in 2022) comes from the industrial sector, which continues to consume fossil fuels for energy and feedstocks [1]. Over the last twenty years, the global industrial sector has used nearly the same mix of energy sources, with fossil fuels (coal, oil, and natural gas) still constituting 73% of its final energy consumption [2]. This long-term dependence on fossil fuels for industrial energy is a main contributor to persistently high emissions and the 1.1^{o}C rise in the global average temperature above pre-industrial levels [3]. In order to achieve the goals of the Paris Agreement and limit warming to 1.5^{o}C, the industrial sector must decarbonize.

While the power generation and transportation sectors have made progress in increasing their share of renewable energy and electrification, industry has been relatively slow to decarbonize. Multiple challenges – a diverse set of industrial processes with both combustion and process emissions, high-cost equipment with long lifetimes, and competitive international markets for its products – make emissions from industry hard to abate [4]. However, since nearly two-thirds of industrial energy demand is attributable to one cross-cutting activity, the generation of heat, there are opportunities to reduce industrial emissions on a broad scale [5].

1.2 Conventional Industrial Process Heat and Low Carbon Heat Technologies

The United States is among the top three contributors to global industrial GHG emissions, currently after China and India, which makes it a main target for global decarbonization goals. In the US, industrial process heat accounts for about 9% of the country's total emissions [6]. Essentially all industrial process heating occurs in the manufacturing sector, which constitutes over 75% of industrial energy consumption in the U.S. [7], [8]. For decades, industrial process heating demand has been met by the combustion of natural gas, byproduct fuels (waste products from other processes combusted for energy), coal, and fuel oils due to their relatively low costs, domestic availability, and ability to supply high-temperature heat [9]. In manufacturing facilities, industrial process heat is generated primarily through conventional boilers, combined heat and power (CHP), and direct process heating units (e.g., furnaces, kilns, ovens) [9]. Although these heating end-uses represent some uniformity across manufacturing, the reality is that process heating varies widely among industries and even facilities, which have different process units, energy carriers, operating schedules, and temperature requirements depending on the products being manufactured. The heterogeneity of industrial process heating makes it difficult for researchers to develop and evaluate technically feasible and cost effective decarbonization technologies.

Numerous low carbon technology solutions for industrial process heating have been proposed, and many are commercially available today. Broadly, these include electrification, clean energy-based heating via solar thermal, geothermal, or nuclear, hydrogen (through its production by low carbon routes and its use as a low carbon fuel), biomass, carbon capture and storage (CCS), and energy efficiency [10]–[14].

Much of the research related to industrial heat decarbonization revolves around this common set of low carbon solutions but emphasizes the need for more in-depth modeling and analysis that estimates energy and emissions of low carbon technologies compared to incumbent technologies. Thiel et al. argue that decarbonizing industry requires decarbonizing heat and highlight R&D needs for four pathways: zero-carbon fuels (hydrogen, biofuels, and synthetic hydrocarbons), zero-carbon heat (solar thermal, geothermal, and nuclear), electrification of heat, and efficiency [15]. In identifying thermal energy grand challenges for decarbonization, Henry et al. call for improved thermal energy storage systems and for adopting electrification and clean hydrogen in industrial processes [16]. Friedmann et al. evaluate biofuel combustion, hydrogen combustion, electrification, nuclear heating, and CCS in heavy industry applications, finding that feasibility, costs, and emissions impacts of low carbon heat options remain poorly understood and that primary data on the industrial sector is scarce, further adding to knowledge gaps and risk [17]. Furthermore, the U.S. Department of Energy (DOE) Industrial Decarbonization Roadmap explicitly states the need for analyzing low carbon process heat solutions, describing key technical characteristics (e.g., temperature ranges, efficiency, economics, geography), and providing case studies [18].

1.3 Research Gaps and Data Limitations in Industrial Heat Decarbonization Analysis

Despite research efforts thus far, there remain research gaps related to feasibility assessments of low carbon heat options for industrial applications and lack of industrial data. First, feasibility assessments require determining the applications of low carbon technologies to meet industrial process heating demands, evaluating their technical potential, comparing environmental impacts and costs to conventional heat systems, and identifying the key levers for policy or research, development, and demonstration efforts.

Research methods in energy systems modeling and analysis are well-equipped to answer these questions. In general, the field of energy systems modeling and analysis uses quantitative and computational approaches to simulate, design, and assess environmental and economic impacts of energy systems. It makes use of many well-known research tools, such as techno-economic analysis (TEA) and life-cycle assessment (LCA), and incorporates many types of modeling approaches, including top-down models, using national or regional sector-level data and interactions, and bottom-up models, using unit process data and engineering principles. These methods can be used to quantify important factors needed to assess process heat technologies, including process integration, life-cycle environmental impacts, geospatial granularity, and cost metrics. Studies that have specifically analyzed industrial process heat decarbonization include some of these factors in their scopes (Table 1-1), but there is a lack of analysis considering the combination of unit process energy demand, process integration for low carbon technologies, and quantification of life cycle emissions and costs. These factors are necessary for accurately representing the complexities of the industrial sector.

Second, the lack of facility-level data in industry is a major limitation in industrial heat decarbonization research. Facility-level data includes unit processes, energy performance data, fuel use, and equipment vintage, among other factors, but this data is rarely available as it is protected by industrial companies for proprietary reasons. For this reason, many analyses employ top-down modeling approaches using national or regional energy data, sacrificing unit-level factors that reflect the physical operations at facilities and affect the feasibility of low carbon technologies. Of the facility- and unit-level data that is available, technology characterizations can be outdated, and advanced data analysis is often needed to extract useful unit type, energy performance, and fuel type parameters.

Table 1-1. Literature review of industrial heat decarbonization analyses. Green shading means the technology is included. NZ is New Zealand. AUS is Australia. EU is Europe. ☑ means the factor is included as part of the analysis. ○ means the factor is mentioned but not quantified.

Ref.	Low carbon heat options							Industrial sector focus	Region	Type of analysis	Analysis evaluates or quantifies:				Primary economic output	Policy discussion
	Bioenergy	CCS	Electrify	Geothermal	Hydrogen	Nuclear	Solar				Unit process	Process integration	Life cycle emissions	Non-energy benefits		
[12]					■			Refining, chemicals, paper, iron and steel, cement	US	Technical and economic potential		○			Levelized cost of energy	Tax credits, R&D, carbon pricing
[17]	■	■	■		■	■	■	Cement, primary iron and steel, methanol and ammonia, and glassmaking	Global	Economic potential					Cost per ton of product	Procurement, tax credits, tariffs, infrastructure, R&D, regulations
[18]	■	■	■	■	■	■	■	Iron and steel, chemicals, food and beverage, refining, cement	US	Technology roadmap	○	○	○	○		
[19]	■	■	■		■			Cement, iron and steel, chemicals	Global	Technology roadmap	☑					Carbon pricing, subsidies, infrastructure development, R&D, mandates
[20]	■		■	■			■	Food, pulp and paper, wood, chemicals, ceramics	NZ	Technology roadmap and inventory of case studies	☑			○		
[21]	■			■	■		■	Aluminum, food, ammonia, iron and steel, cement, petroleum, pulp and paper	AUS	Technical potential	☑				Investment cost of electrolysis (case study)	Subsidies, targets, demonstration, tax credits, standards, carbon pricing
[22]	■	■	■		■			Cement, steel, ethylene, ammonia	Global	Technical and economic potential	☑				Cost per ton of production and CO_2	Targets, regulations, R&D, infrastructure
[23]				■		■	■	Food, pulp and paper, refining, chemicals, cement, iron and steel	US	Technical potential						
[24]			■					Steel, pulp and paper, refining, aluminum, glass	US	Technical potential	☑	○				
[25]							■	Low temperature heat (<90C)	EU	Economic optimization					Investment cost of solar thermal	

1.4 Contributions of Research

In this research, an energy systems analysis framework is developed to evaluate low carbon industrial process heat technologies, providing more accurate ways to represent the technical and economic complexities in industrial process systems. Specifically, this framework consists of analyzing industrial process data, characterizing incumbent and emerging low carbon process heat technologies, modeling process energy demand and supply, and quantifying environmental and cost impacts with temporal and spatial detail. Figure 1-1 shows a schematic of the framework.

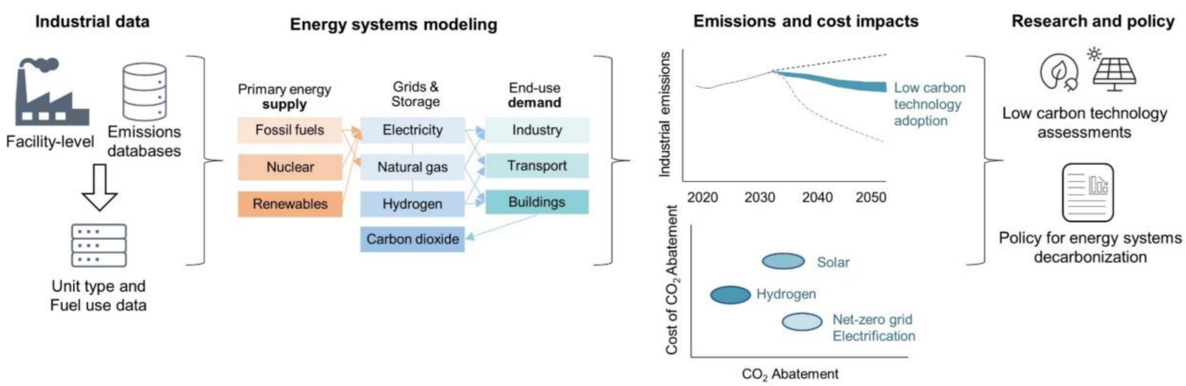


Figure 1-1. Energy systems analysis framework for decarbonizing industrial process heat

The work in this thesis moves the field of industrial decarbonization analysis forward by providing technical characterizations of conventional and low carbon process heat technologies, developing new datasets and analyses of unit-level industrial processes, and applying this framework to several case studies across the U.S. manufacturing sector. The outputs of this research can connect with other industrial energy models and inform policymakers and industrial plant managers of feasible technology options for decarbonizing industrial heat.

1.5 Outline of Research

Each chapter in this dissertation serves as part of the framework development or as a case study where it is applied. Chapter 2 is a review of solar industrial process heat (SIPH) technologies and applications in industry. This work was done in collaboration with researchers at the National Renewable Energy Laboratory (NREL). Chapter 3 is a continuation of the SIPH project with NREL. This chapter covers modeling efforts to determine technical and economic opportunities for SIPH technologies across U.S. manufacturing. The research details how SIPH heat supply is modeled based on solar resource availability and land use and is matched to industrial process heat demand on a county-level basis and hourly timescale over the course of a year. It also discusses case studies that calculate the economic parity of SIPH systems with conventional process heating.

Chapter 4 builds on these analyses, focusing on one particular electrification technology, electric boilers. In this chapter, conventional industrial boilers are characterized by key technical parameters (industrial subsector, fuel type, capacity, location) by integrating unit-level data from national emissions databases, and the potential of electric boilers to reduce emissions is analyzed under different electricity grid scenarios. Chapter 5 summarizes work conducted at NREL during a graduate internship, which expands the analysis of emissions databases described in Chapter 4. In this research, sources of industrial data are explored to conduct analyses on unit-level data and to define key data fields for industrial energy models.

In Chapter 6, the framework for evaluating low carbon technologies developed in Chapters 3 and 4 is expanded and applied in a case study comparing electrification and clean hydrogen to conventional process heat systems for two chemicals manufacturing industries. Environmental impacts and system costs are quantified. Finally, in Chapter 7, the thesis concludes with major takeaways for industrial heat decarbonization analysis and recommendations of future research.

2. Review of Solar Thermal and Electric Industrial Process Heat Technologies and Applications

This literature review of solar industrial process heat (SIPH) summarizes the industrial process heating landscape in the United States, the current state of SIPH technologies and operating installations worldwide, potential applications for U.S. industry, modeling and data needs for determining technical potential, and present barriers to adoption. The review introduces ways to characterize low carbon process heat technologies and provides insights on modeling approaches for evaluating SIPH projects.

This chapter is adapted from the following peer-reviewed article [26]:

- Schoeneberger, C., McMillan, C. A., Kurup, P., Akar, S., Margolis, R., Masanet, E. "Solar for Industrial Process Heat: A Review of Technologies, Analysis Approaches, and Potential Applications in the United States." *Energy*. 2020, 206, 118083.

2.1 Introduction

Industrial process heating (IPH) accounts for 50% of all manufacturing energy use (including fuel, steam, and electricity), which amounted to 8% of U.S. primary energy consumption in 2014 [27] [28]. The overwhelming majority, nearly 90%, of U.S. IPH demand is met by the combustion of fossil fuels, namely natural gas, byproduct fuels, and coal. Industry's reliance on fossil fuel combustion for process heat has persisted for decades – in 1991, 92% of U.S. IPH was met by fossil fuels [29]. In addition to the greenhouse gas (GHG) emissions impact on climate change, fossil fuel combustion contributes to air pollution near industrial plants and is susceptible to changes in production costs due to the volatility of fuel prices. Switching to alternative methods of industrial heat generation would reduce these negative effects of fossil fuel use.

With increasingly cost-effective and efficient solar technologies, SIPH – the utilization of solar energy for process heating – is a promising low carbon process heat option [30]. SIPH technologies include solar thermal (ST), photovoltaic (PV), and hybrid systems that make use of solar energy and convert it to heat for a range of IPH needs. The process temperature of a unit process within a manufacturing plant is often used to characterize process heat demand and is necessary to evaluate SIPH technologies for specific applications. SIPH systems currently in operation tend to generate process heat temperatures from 60^{o}C to 250^{o}C, depending on the technology [31]. This range coincides with many process heat applications in energy-intensive industries, where roughly 50% of process heat demand occurs at temperatures of 300^{o}C or less [32]. Beyond process heat temperatures, evaluations of SIPH systems for industrial applications need to consider process integration and opportunities for energy efficiency measures to determine their full technical and economic potential.

The complexity and heterogeneity of the industrial sector make it difficult for both modeling efforts to evaluate SIPH potential and SIPH adoption at industrial facilities. Modeling requires data on process heat demand with temporal granularity, technical characterizations of SIPH technologies, and facility-level cost metrics, among other factors. The lack of industrial data in the U.S. is a challenge for estimating heat demand and for appropriately modeling the integration of SIPH systems into existing industrial processes [33], [34]. However, there is a growing number of successful SIPH installations worldwide, especially in the food and beverages industries, but certain economic factors, such as high upfront investment costs, low fuel prices in some regions, and perceived risk, have prevented wider adoption [35].

Several studies have quantified the technical potential of SIPH for certain countries and regions, as well as with a global scope [36]. The International Renewable Energy Association

(IRENA) estimated a best-case scenario SIPH potential of 15 EJ (14 quads) by 2030 out of an expected 173 EJ (164 quads) for total industrial energy use in 2030 [37] [35]. The International Energy Agency (IEA) established a program called Solar Heating and Cooling (SHC) in 1977 to promote research on solar thermal energy, and three of its research projects, Tasks 33 (2003-2007), 49 (2012-2016), and 64 (2020-2023) have focused specifically [38]. In the US, the Solar Energy Research Institute (SERI), which is now called National Renewable Energy Laboratory (NREL), conducted several studies on SIPH during the 1980s [39]. Recent studies have focused on broad integration of renewable energy in energy or on reviews of exclusively solar technologies and applications in specific industries, often at the global level [40] [41] [42]. This review addresses challenges related to the lack of knowledge of industrial energy use in the U.S. and of key technical and economic parameters needed for SIPH evaluations.

Industrial process heating involves the treating and transformation of raw materials into intermediates and industrial products through the application of heat [43]. The process for applying thermal energy to materials varies by technology but is typically characterized by energy carrier, or heat input, into a unit process: fuel, steam, and electricity [44]. Fundamentally, these processes rely on heat transfer mechanisms: conduction, convention, and radiation. Direct IPH occurs when heat is generated within or in contact with the material, and indirect heating occurs when heat in generated separately and transferred through working fluids, or heat transfer fluids (HTFs), panels, or radiant burner tubes [45].

Fuel-based technologies involve the combustion of solid, liquid, or gaseous fuels, usually in the presence of air or oxygen, to generate heat for the material being processed [45]. This IPH end-use is often referred to as direct process heating. In U.S. manufacturing, fuels for direct process heating are primarily natural gas (51%) and byproduct fuels (waste gas, black liquor, wood byproducts, in total 36%) [46]. Steam-based technologies use heat from combustion to make steam and transfer it to the process directly by steam sparging or indirectly through steam distribution and heat exchangers [44]. Conventional boilers and combined heat and power (CHP) units are typical combustion technologies for steam generation. Electric process heating technologies use electric currents or electromagnetic fields to generate heat for a process directly through a material or in a heating element which transfers heat to the material [45]. There are various types of electric heat technologies, including resistance heating, induction heating, microwave processing, electric arc furnaces, electric boilers, and heat pumps, but electricity accounts for only 5% of U.S. IPH energy consumption [46].

In the US, there are five energy-intensive manufacturing subsectors that are responsible for 82% of total process heating energy use – chemicals, petroleum refining, forest products (wood and pulp and paper), iron and steel, and food and beverages [47]. Figure 2-1 shows the IPH energy use of subsectors with the highest energy use. Since electricity-based technologies make up about 3% of IPH energy use among these subsectors, IPH energy use from electricity is omitted. These subsectors represent target areas for SIPH, where it can have the greatest effect in reducing fuel use.

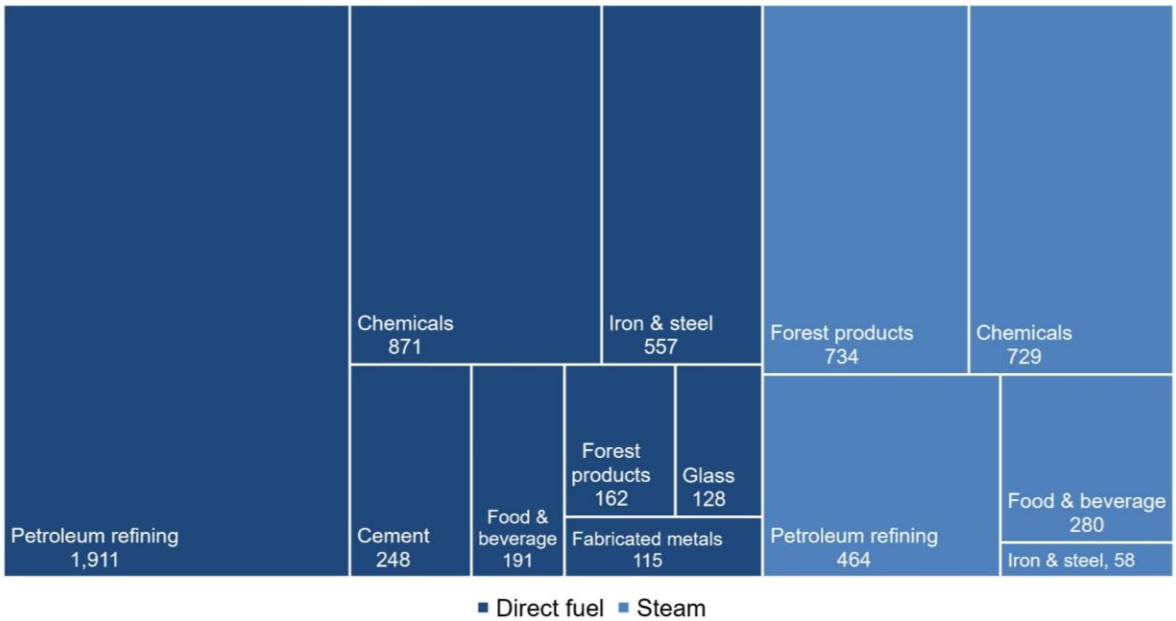


Figure 2-1. Process heating energy use (TBtu) in 2014 of U.S. industrial subsectors. Data from [47]

In addition to the energy carrier and IPH end-use technology, there are numerous heat operations that affect the type of equipment used and the ways alternative technologies could be integrated within manufacturing facilities. The major types of heat operations and relative amounts of process energy use by energy source are shown in Figure 2-2. These heat operations, such as fluid heating, drying, smelting/melting, refer to the general heat transfer goal, whereas unit processes refer to specific steps in the manufacturing process that require heat, such as distillation. Gas and “Other” fuels, which refer to waste products, such as refinery gas, sawdust, or petroleum coke, represent the largest portion of process energy use for heating operations and, especially, for fluid heating, a form of heating that can be supplied by SIPH systems.

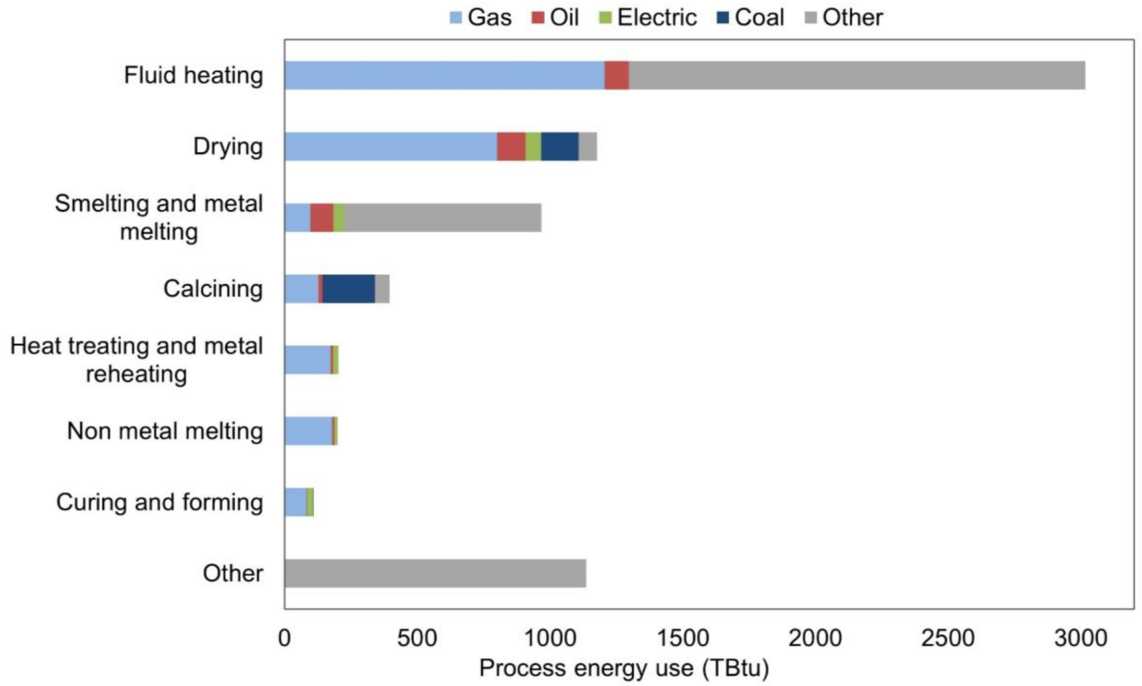


Figure 2-2. Process energy use for types of heat operations by energy source in the U.S. in 2010. Data from [44]**,** [45]

Another important factor related to heat operations is the hours of operation or operating schedule. The load being heated in a manufacturing facility can run through process heat equipment continuously or in a batch process, as in discrete steps for set conditions and time [45]. The distinction between continuous and batch operations affects the estimation of heat demand with accurate temporal detail and the need for thermal energy storage (TES) as part of SIPH systems.

2.2 Solar Thermal and Electric Heating Technologies

While some emerging SIPH technologies are still in development, many are commercially available and in operation today. The most common ST technologies, electric heat technologies powered by PV, hybrid systems, and TES are described in this section.

Two high-level categories of ST technologies are non-tracking collectors and concentrating collectors. Non-tracking collectors are most commonly used in low-temperature (<150^{o}C) processes and include flat-plate collectors (FPCs), evacuated tube collectors (ETCs), compound parabolic collectors (CPCs), unglazed collectors, and air collectors [48]. In general, non-tracking collectors consist of an absorber plate that catches solar radiation and tubes underneath that contain a working fluid that transfers the heat to the application [49]. FPCs typically have a dark absorber plate with glass tubes containing water or oil-based fluids as the HTF and reach maximum efficiency up to 80^{o}C. ETCs have several rows of dark tubes encased in vacuum-sealed glass tubes that trap heat more efficiently than FPCs [50] [51]. CPCs utilize a non-tracking reflector that directs solar energy to the header carrying the HTF and can produce heated fluids up to 200^{o}C at more than 50% efficiency, defined as the percentage of solar energy hitting the collector and converted to useful heat energy [52].

Concentrating collectors for SIPH operate by the same principles as concentrating solar power (CSP) for electricity generation but differ in dimension, production, and mounting. They can supply heat at temperatures up to 400^{o}C [53]. Concentrating collectors include Linear Fresnel (LF), parabolic trough collectors (PTCs), and heliostats, or central receiver systems. These types of collectors have flat (as in LF and heliostats) or parabolic (as in PTCs) mirrors that concentrate light toward a receiver, a header line or tower receiver, heating the HTF. HTFs with LF and PTCs can reach up to 400^{o}C, while with heliostats, temperatures can reach 600^{o}C [54] [55]. Despite the high temperatures achieved with heliostats, they are not commonly used for IPH applications, although there are some current cases with solar rotary kilns in cement manufacturing [56] [57].

Figure 2-3 shows a cost comparison among some solar collectors for small and large systems. The IEA SHC Task 49 established a database of solar heat for industrial processes, referred to this project as SHIP, for many existing ST installations worldwide [58]. The database includes both technical and economic data, but it should be noted that it consists of voluntary submissions, where cost accounting methods may vary. The total investment costs and installed thermal power data for the various collectors are based on an analysis of 164 installations.

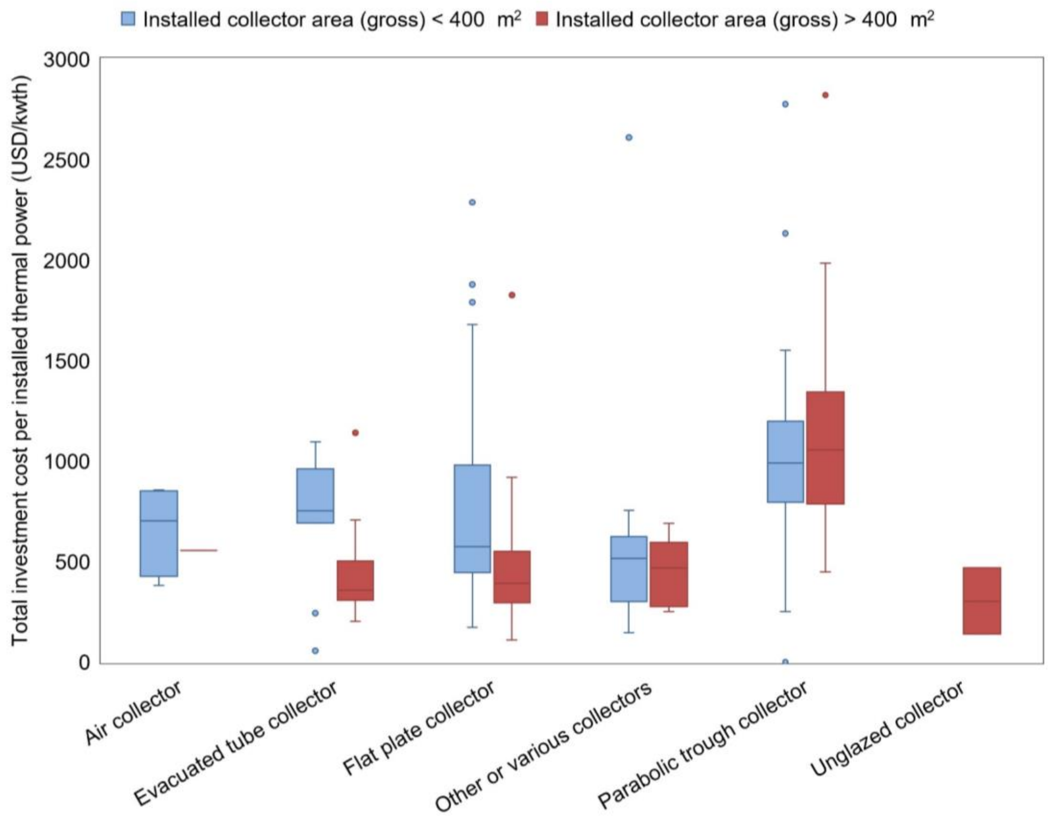


Figure 2-3. Total investment costs per installed thermal power for ST collector types (USD in 2014). Each box represents data between the first and third quartiles; the whiskers represent the first quartile minus 1.5 * interquartile range and the third quartile plus 1.5 * interquartile range. Data from [58]

Electric heating technologies assisted by PV work by converting solar energy to electricity that can power the heating equipment or that can be added to the grid. PV-resistive water heating systems involve the direct coupling of the PV array to resistive heating elements immersed in a water tank [59]. Induction heating has been tested for IPH applications in the food industry but has not been implemented yet on a commercial scale [60]. Heat pumps are especially useful for low temperature heat and are currently used in food and wood manufacturing industries, in applications where their coefficient of performance (COP), which is a measure of efficiency, is greater than 3 [61]. Lastly, there are PV-thermal (PVT) hybrid systems that use PV modules to generate electricity and a HTF in contact with the back on PV modules to transfer additional heat, but they are still in development and not used commercially [62].

TES systems bridge the gap between the supply of solar energy, a variable renewable energy resource that changes hourly and seasonally, and IPH demand. These systems are often classified as sensible heat storage, latent heat storage, and thermochemical storage [63]. In sensible heat storage, heat energy is stored in a material with high specific heat or thermal conductivities, usually hot water (for $<100^{o}C$), pressurized water (for $>100^{o}C$), molten salt, or solids, such as gravel or concrete [64] [65] [66] [67]. Latent heat storage systems charge and discharge heat by a phase transformation of the material at constant temperature, whereas thermochemical storage makes use of energy absorbed or released when breaking or forming chemical bonds, but both these types of TES are in the R&D phase [68].

2.3 Trends in Global SIPH Installations

An analysis of SIPH systems installed globally and across manufacturing industries has provided insights on target industries for SIPH adoption and key areas for future research. The IEA Task 49 SHIP database reports on 313 installations, and although there were an estimated 741 installations in 2018 worldwide, accounting for industrial sectors beyond manufacturing, such as mining and agriculture, it represents the most comprehensive source of case studies with process data [69].

SIPH systems are installed in at least 34 countries, with the highest percentage of identified installations in Mexico and India (Figure 2-4), which have abundant solar resources. The distribution of SIPH installations in the US, including the Southwest, Midwest, Southeast, and

Northeast, shows the possibility for systems to operate in places other than the solar resource-rich Southwest and that many factors other than resource availability, such as fuel costs, industry concentrations, and financial flexibility influence SIPH adoption.

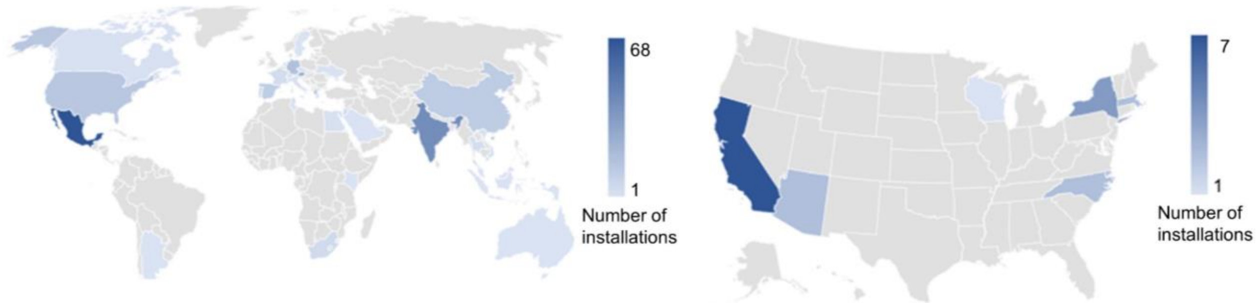


Figure 2-4. Global and U.S. distributions of SIPH installations in the manufacturing sector. Data from [58]

Most of the installed SIPH systems globally are in the food and beverages subsectors, but the textiles subsector also has a high number of installations and large average installed capacity (Figure 2-5). Low temperature process heat demand contributes to the high frequency of SIPH systems in these subsectors. The capacity of SIPH systems typically corresponds to the size of collector area, which affects investment and maintenance costs. While the presence of SIPH in food and beverages makes them target subsectors for increased adoption in the US, the lack of installations in chemicals and paper and wood manufacturing, which are among the top five subsectors in IPH energy consumption and have low to medium temperature heat demand, indicate barriers worth investigating.

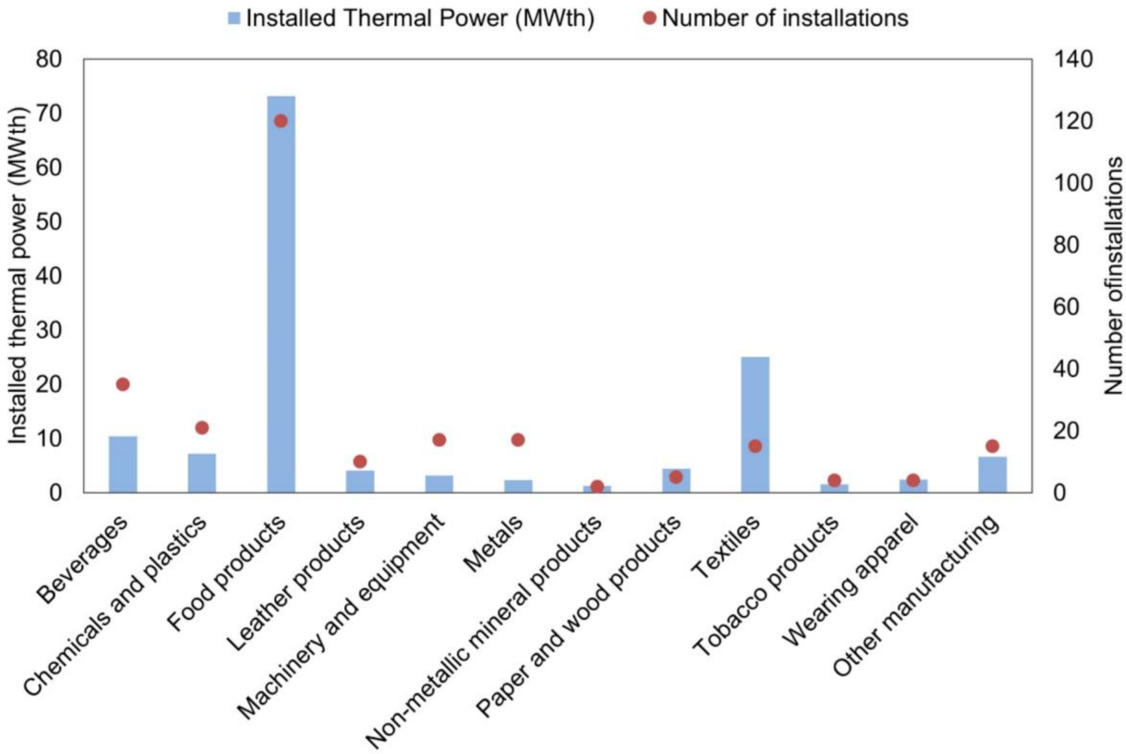


Figure 2-5. Number of global SIPH installations and installed thermal power for manufacturing subsectors. Data from [58]

The number of installations and temperature ranges of various ST technologies are shown in Figure 2-6. FPCs and PTCs are the most frequently used solar collectors. FPCs in this group of installations supply heat at process temperatures up to 130^{o}C, and PTCs up to 250^{o}C. In general, PTCs comprise 82% of the global market [70], but FPCs are likely most prevalent in this group of installations because of their lower costs compared to PTCs.

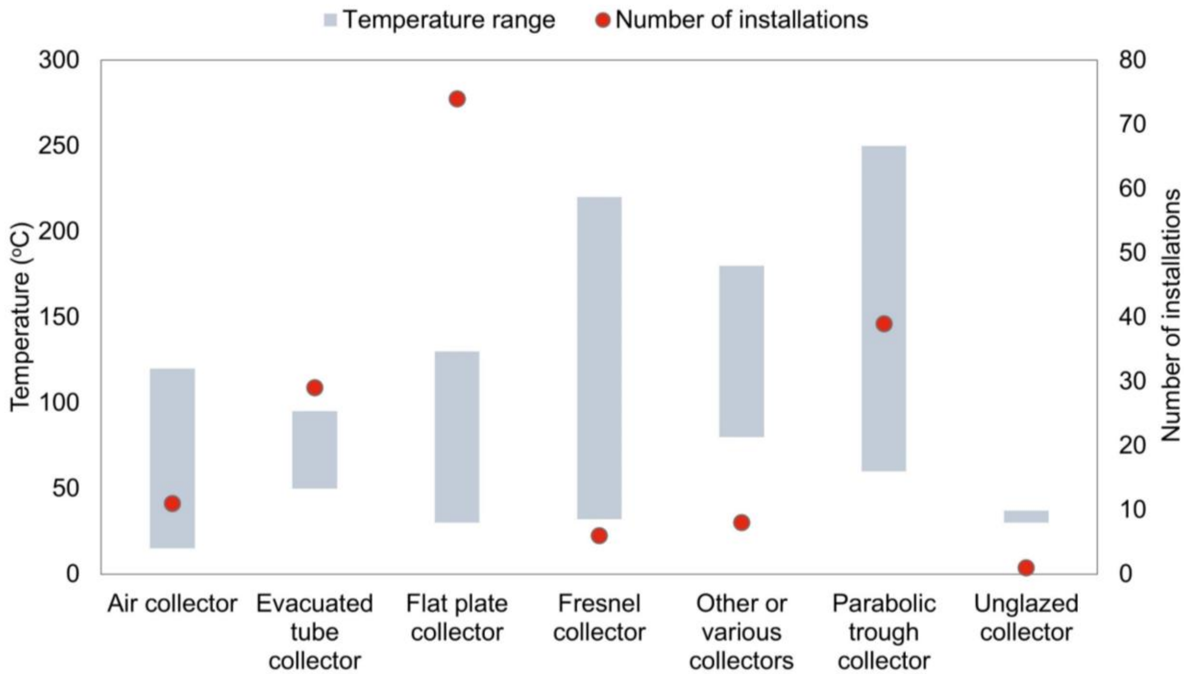


Figure 2-6. Number of global solar thermal SIPH installations and temperature range for solar collector types. Data from [58]

Sixteen SIPH systems were analyzed in the U.S. – eleven in food industries, four in beverages, and one in textiles. Table 2-1 shows the site information and technical data for each of the SIPH installations. Most installations are similarly in the food and beverage industries, which can be attributed to the low temperature (<150°C) requirements of their unit processes, but in total these SIPH systems account for <0.1% of total annual process energy use in food and beverages.

Table 2-1. SIPH Projects in the US. All costs are in installation year USD. Data from [58], [71], [72], [73], [74]

Name	Location in US	Manufacturing subsector	Year installed	Solar collector	Number of collectors	Installed collector area (gross), m²	Installed thermal power (actual), kWth	Unit operations	Total investment costs, $	Estimated annual CO2 emissions displaced, t
Acme McCrary	Asheboro, North Carolina	Textiles	2012	FPC	-	743	520	Drying	-	-
Adams Farm Slaughterhouse	Athol, Massachusetts	Meat products	2013	FPC	70	297	208	Cleaning	-	44
Barrington Brewery & Restaurant	Great Barrington, Massachusetts	Beverages	2009	FPC	30	82	57	Other process heating	51611	7
Battenkill Valley Creamery	Salem, New York	Dairy products	-	FPC	20	53	37	Cleaning	34002	16
Brown's Brewing Co	Hoosick, New York	Beverages	-	FPC	20	53	37	Cleaning	35217	11
Carriers & Sons	California	Food products	2002	Air collector	-	300	210	Drying	-	-
Frito Lay	Arizona	Food products	2008	PTC	-	5068	3548	General process heating	-	-
Gatorade	Phoenix, Arizona	Beverages	2008	FPC	-	4221	2955	General process heating	-	-
Keyawa Orchards	California	Food products	2003	Air collector	-	864	605	Drying	-	-
Kreher's Poultry Farms	New York	Food products	2002	Air collector	-	50.4	35	Drying	-	
Milwaukee Brewing Co.	Milwaukee, Wisconsin	Beverages	2013	FPC	28	104	73	Other process heating	94114	12
Prestage Foods	St Pauls, North Carolina	Food products	2012	FPC	-	7804	5463	Cleaning	5639098	-
Stapleton-Spence Fruit Packing Co.	San Jose, California	Fruit and vegetables	2012	Unglazed collector	500	2637	1846	General process heating	488722	150
Sunsweet Dryers	California	Food products	2004	Air collector	-	110	77	Drying	-	-
Frito Lay	Modesto, California	Food products	2008	PTC	384	5017	492	-	-	-
Horizon Nut	California	Food products	2017	PTC	-	72 (aper.)	50	Drying, roasting	-	-

2.4 Methods for Modeling SIPH Potential

Recently, many assessments on SIPH potential have been focused on certain countries, regions, industries, and solar heat technologies. These assessments typically quantify potential in terms of energy per year or percentages of heat demand that could be met with SIPH. Table 2-2 contains a list of assessments evaluating SIPH in single countries, their coverage of industrial subsectors, and quantification of SIPH potential and percentage of demand for low to medium process temperature heat.

Table 2-2. SIPH potential for multiple manufacturing subsectors in single countries [75]–[79]

Country	Year	Industrial subsectors	SIPH Potential (TWh/year)	SIPH Potential (% of IPH demand)	Temperature range considered (ºC)
Germany	2012	Chemicals, Food and beverages, Paper, Motor vehicles, Fabricated metal, Machinery, Rubber and plastic, Textiles, Electrical equipment, Printing, Wood	16	3.4	<300
Italy	2005	Food and beverages, Tobacco, Textiles, Leather, Pulp and paper, Chemicals, Transport equipment	8.9	3.7	-
Austria	2004	Food and beverages, Textiles, Transport equipment, Other	1.5	3.9	<250
Spain	2001	Food and beverages, Tobacco, Textiles, Leather, Pulp and paper, Chemicals, Transport equipment	1.4	3.4	<250
Portugal	2001	Food and beverages, Tobacco, Textiles, Leather, Pulp and paper, Chemicals, Transport equipment	4.7	4.4	<250
Netherlands	2001	Food and beverages, Textiles, Pulp and paper	0.6	3.2	<60

Other regional studies have analyzed SIPH potential for a single industry or a select few within a country – food and textiles in Mexico [80], minerals and metals processing in Australia, [81], paper in India [82], surface treatment, food, chemical, textiles, and leather in Egypt, Pakistan, and Morocco [36].

In the US, the first efforts to evaluate SIPH in the 1980s estimated the technical and economic potential of solar thermal technologies, finding that they could provide 7.27 quadrillion Btus by 2000 [83], and 0.1 quads [84] and 10 quads [85] by 2020. These studies modeled solar technologies as generic systems operating under assumptions of regionally typical climates and accounted for systems costs and costs of competing fuels; however, in the last 40 years, technologies and data availability have improved, and the landscape of competing fuels has evolved. In more recent years, a U.S. study estimates the resource and technical potential of SIPH for the most energy-intensive manufacturing subsectors in California, but location-specific resource potential was not matched to process heating demand [55]. In another U.S. study, McMillan et al. provide an estimate of technical potential for SIPH, 1,480 PJ/year, or about 25% of annual energy use of the 14 industries evaluated, assuming a maximum temperature of 1000°C and maximum system size of 100 MW_t, but this study does not distinguish results by solar technologies and does not consider solar resource availability.

Many of the studies discussed above have different methods and scopes for evaluating SIPH, but there are several key parameters common to each and also featured in case studies that are important for accurately assessing potential. Based on a review of case studies, the following parameters in Table 2-3 are found to be significant for modeling SIPH systems. Process heat characteristics, such as temperature, throughput, and unit processes, are essential for determining applicable SIPH technologies. Load profiles contain information on the hourly operating schedule, which is necessary for TES needs and SIPH system sizing. Energy efficiency of incumbent technologies helps determine the exact process heat demand and allows for measures that could reduce heat demand in parallel with SIPH adoption. Parameters related to the supply of solar heat, including solar irradiance, available area, TES needs, and integration points in a facility define the

SIPH system, while economic factors shed light on the highest cost barriers, which future research and policy could address. For future SIPH modeling efforts, there is a need to incorporate more analysis of process heat load profiles, energy efficiency measures, land availability, TES, and process integration. Furthermore, a cost framework that compares solar technologies and incumbent process heat technologies is needed for facility-level decision making and better opportunities for technology adoption.

Table 2-3. Parameters in SIPH case studies [56], [57], [86]–[97]

		Process heat demand			**Solar supply**				**Economic factors**		
Study	**Year**	Process heat characteristics	Process heat load profiles	Energy efficiency potential	Solar irradiance	Land for solar field / Rooftop area	TES	Integration into facility	Supply-and-Demand-side equipment costs	Payback period, Rate of return	Savings from reduced fuel use
Meier et al.	2004	X			X						
Meier et al.	2006	X			X				X		
Schnitzer et al.	2007	X		X			X		X	X	X
Fuller	2011	X			X	X			X	X	
Quijera et al.	2011	X	X		X	X	X	X			X
Dantas	2014	X	X	X	X		X		X	X	
Lauterbach et al.	2014	X	X	X	X	X	X	X			
Mauthner et al.	2014	X			X	X	X	X			X
Quijera et al.	2014	X	X		X	X	X	X			X
Alonso et al.	2017	X					X				
Eihnozler et al.	2017	X	X		X		X	X	X	X	X
Suresh et al.	2017	X			X				X	X	
Tregambi et al.	2018	X			X						X
Wallerland	2018	X	X	X	X		X	X	X		X

2.5 Process Integration and Efficiency Measures

Several of the key modeling parameters needing more attention in SIPH analyses are the integration of solar technologies in existing industrial processes, unit process heat characteristics within industrial subsectors, and the addition of efficiency improvements to reduce energy demand and aid SIPH technology adoption. First, there are multiple factors to consider when integrating SIPH systems at manufacturing facilities: the distinction between central steam and hot water distribution and process-level supply, heat transfer medium in central supply systems, and the conventional process heat equipment. Figure 2-7 shows a few possible configurations altogether in a simplified diagram. In some cases, solar collectors or PV-electric heating are used for steam or hot water generation that connect to central heating supply, whereas in other cases, a solar technology is applied directly to a particular process.

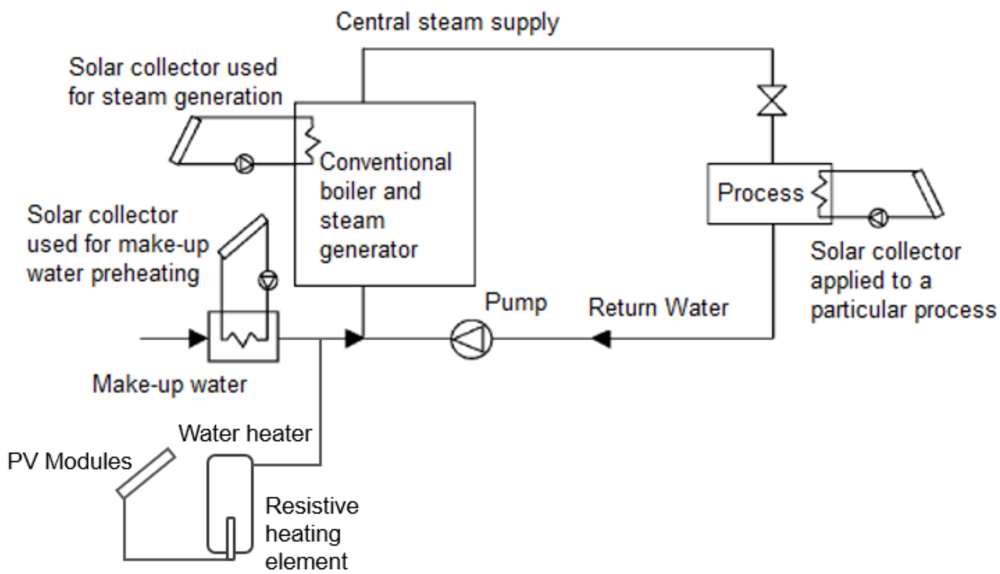


Figure 2-7. Configurations for SIPH integration. Adapted from [59], [98]

Another approach to identifying suitable points of integration for SIPH technologies is by accounting for individual unit processes within manufacturing industries. Each unit process represents a single step within the manufacturing process and operates at a specific temperature, depending on the material being manufactured and individual facility. Figure 2-8 shows some of the temperature ranges of major unit processes for manufacturing subsectors alongside the temperature ranges that SIPH technologies can achieve. Most SIPH technologies are suitable for low to medium temperature heat, which aligns with many unit processes in the food and beverages, textiles, wood and paper, and plastics subsectors. Certain electric heating technologies directly paired with PV, such as induction, resistance, and infrared (IF) heating, have potential to reach temperatures greater than 1,000^{o}C but have not been commercially demonstrated [59], [60], [99].

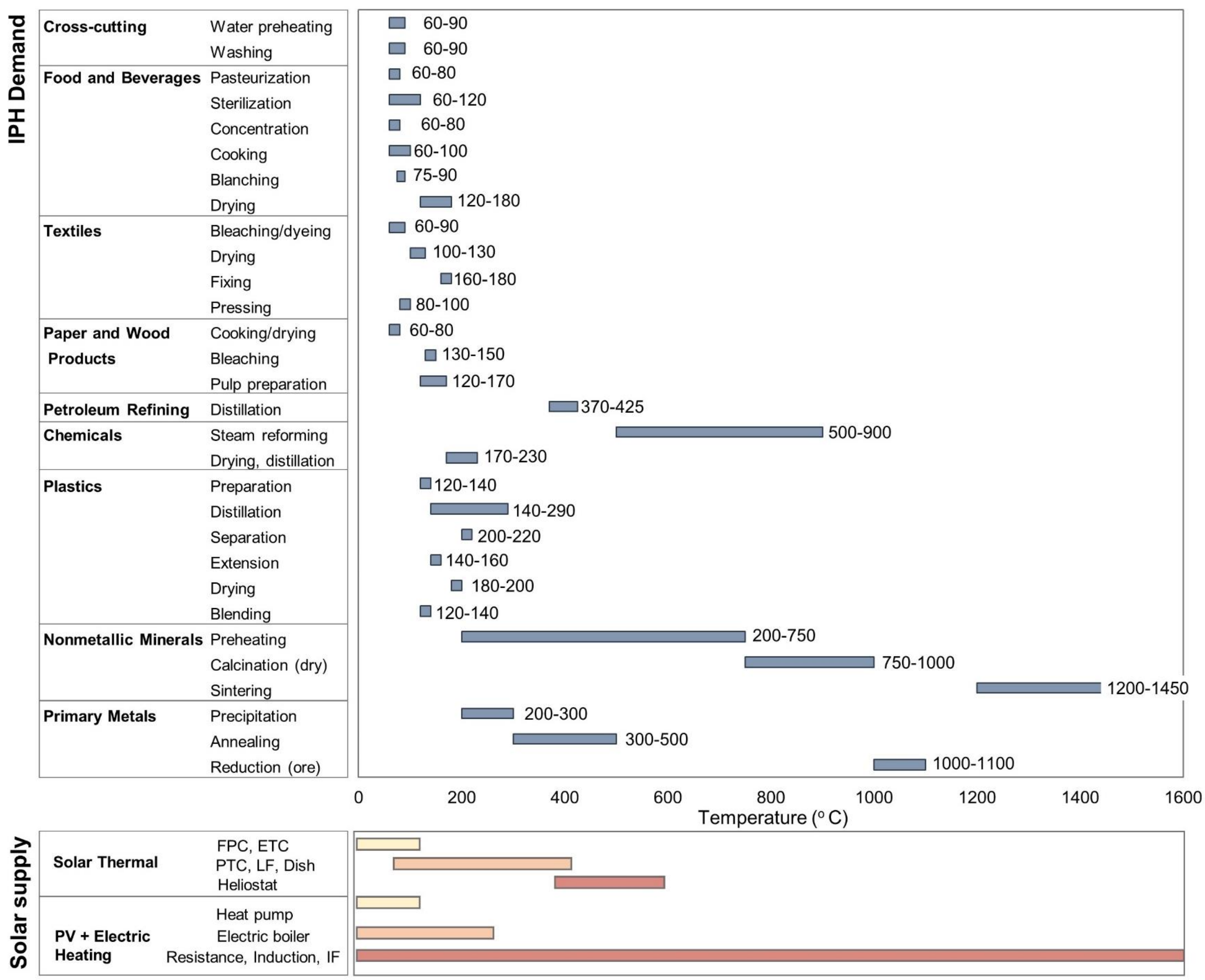


Figure 2-8. Temperature ranges of industrial process heat unit processes and SIPH technologies. Data from [19], [23], [68], [98], [100]–[105]

Based on an analysis of SIPH installations in the IEA Task 49 database, multiple unit processes for which SIPH has supplied heat and the points of integration for SIPH are identified. Figure 2-9 shows a list of unit processes on the y-axis and the ways in which SIPH systems are integrated, such as through the supply line, directly to processes, or make-up water. Overall, SIPH systems are most frequently integrated into make-up water heating (29%), individual processes (25%), and the heating supply line (16%).

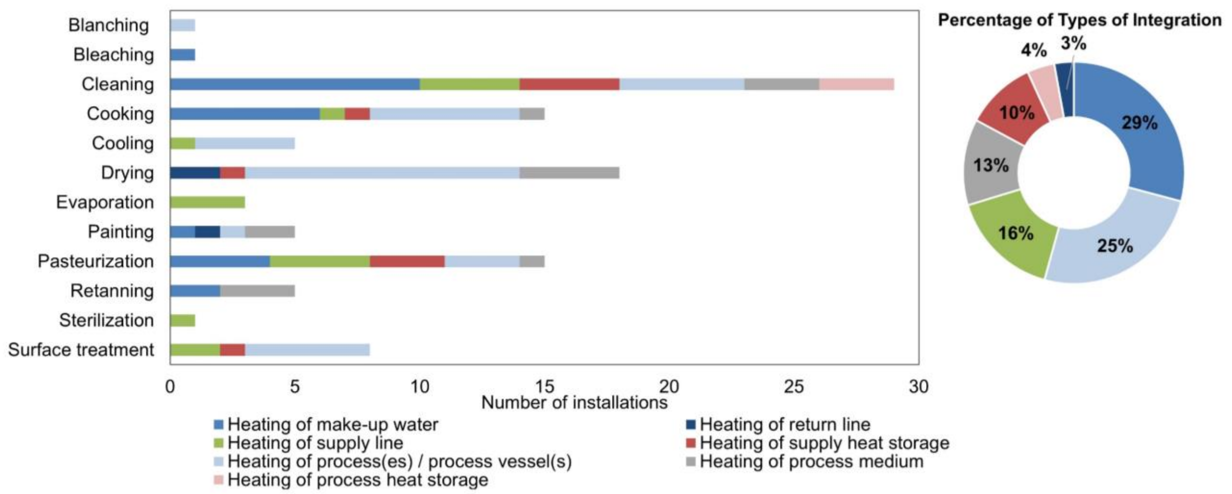


Figure 2-9. Share of SIPH integration points for unit processes [58]

Efficiency measures in industrial process heating can affect unit-level heat demand, thus potentially increasing the technical and economic feasibility of SIPH systems. The literature covering opportunities for industrial energy efficiency is vast, and recent analyses indicate that there remain numerous opportunities across U.S. industrial facilities for efficiency improvements [106]. These opportunities include waste heat recovery, advanced process controls, improved insulation and thermal management to reduce avoidable losses in heating processes and fluid distribution systems, and improved heat transfer materials [45], [107]. Industrial data from two major U.S. DOE programs, Save Energy Now (SEN) and Industrial Assessment Center (IAC), indicates that there are many cost-effective energy saving opportunities that often have simple payback periods less than two years, but manufacturing facilities have yet to pursue them [108]–[110].

2.6 Modeling Challenges and Barriers to Adoption

Despite the immense opportunities for SIPH in many U.S. manufacturing industries, there are both modeling challenges and known barriers to adoption that must be considered in future analysis. Data gaps of process heating energy use estimates at the facility- and unit-level, especially at small facilities, have thus far prevented accurate modeling of solar technologies, which requires a high level of temporal and spatial granularity. An understanding of the temporal variations in unit process operations (continuous vs. batch, year-round vs. seasonal) and in solar resource availability is necessary for determining technical potential. Furthermore, the intermittent nature of solar energy may require the addition of TES, which adds to the complexity of modeling SIPH systems. The inclusion of land or rooftop area availability within or near industrial facilities likewise adds difficulty to modeling efforts, as it leads to questions about new installations, or greenfield sites, vs. retrofit installations, which largely affect system costs.

From the perspective of industrial facilities, cost and reliability are primary concerns. Facilities typically require short payback periods for new capital projects, and with high upfront equipment and installation costs, SIPH projects are at an initial disadvantage. Structural factors in industrial facilities related to reliability pose additional challenges for new technology adoption. These barriers include perceived risk, reluctance to change what is currently working, and downtime [111], [112]. Future analysis should acknowledge these practical barriers in addition to technical and economic challenges.

2.7 Conclusion

This review explores SIPH technologies, current applications worldwide and in the US, and modeling approaches for evaluating SIPH in the U.S. manufacturing sector. Moreover, this research identifies high-level opportunities for solar technologies to meet process heat demand for industrial applications and the major challenges that both modeling efforts and adoption in industry have faced to date. From these insights, several areas for future research are proposed. First, there is a need for a national analysis on SIPH potential in the U.S. manufacturing sector, which has received less attention in recent years compared to countries in Europe. Second, analyses of technical potential should include load profiles of process heat demand, energy efficiency measures, and increased temporal and spatial detail from both heat supply and demand sides. Finally, given that costs are the main driver for industrial facilities, economic potential analyses should identify the parameters that weigh most heavily on SIPH system costs so that future technology development and policy can address them.

3. Modeling the Technical and Economic Potential of Solar Thermal and Electric Industrial Process Heat

This chapter describes modeling approaches for determining the technical potential of solar technologies for industrial process heating (SIPH) and results showing where there is opportunity for SIPH systems in the U.S. manufacturing sector. This research includes analyses of industrial process heat (IPH) demand at the county-level and SIPH system modeling based on SIPH technology performance and availability of solar resources and land. Methods for matching SIPH technologies to applicable process heat demand and calculating technical opportunity are developed. Technical opportunities for SIPH are quantified at an hourly timescale for all counties in the U.S. and across all manufacturing subsectors. Additionally, a framework for evaluating economic process parity, where SIPH costs are equivalent to conventional process heating costs, is established and applied in several case studies. The major findings of this research show the potential for SIPH technologies in the U.S. and discuss practical steps for future analysis and technology R&D that SIPH systems would need to overcome barriers to adoption. The work detailed in Chapters 2 and 3 was completed as part of a two-year project in collaboration with researchers from NREL.

This chapter is adapted from the following peer-reviewed technical report [113] and article [114]:

- McMillan, C. A., Schoeneberger, C., Zhang, J, Kurup, P., Masanet, E., Margolis, R., Meyers, S.; Bannister, M., Rosenlieb, E., Xi, W. "Opportunities for Solar Industrial Process Heat in the United States." Golden, CO: National Renewable Energy Laboratory. 2021. NREL/TP-6A20-77760.

- McMillan, C., Xi, W., Zhang, J., Masanet, E., Kurup, P., Schoeneberger, C., Meyers, S., Margolis, R. “Evaluating the Economic Parity of Solar for Industrial Process Heat.” *Solar Energy Advances*. 2021, 1,100011.

3.1 Introduction

As utility-scale photovoltaic (PV) generation has increased dramatically in the United States since 2014, a renewed focus on developing renewable thermal energy has emerged [115]. SIPH technologies are promising options for supplying renewable heat in industry, but switching to an alternative source of heating is more challenging than switching to an alternative source of electricity generation. These challenges are particularly difficult in the industrial sector, where process heating characteristics vary widely by industry, demand for process heat is often continuous throughout the year, and process equipment can be highly integrated. Such challenges bring about numerous research needs related to modeling process heat demand and solar heat supply and characterizing incumbent and emerging solar technologies, including thermal energy storage (TES) systems, with the ultimate goal of identifying opportunities for SIPH within the U.S. industrial sector.

Previous research on SIPH in the U.S. dates back to the 1980s Brown et al. (1980). Since then, not only have solar technologies become more efficient and cost-effective, and the makeup of fuel use in conventional process heating changed, but also modeling capabilities have improved. This research both addresses the aforementioned challenges and provides novel analyses on U.S. industrial process heat demand at the county-level and on the technical and economic potential for SIPH to meet heat demand with spatial and temporal detail.

Much of the attention on industrial decarbonization has focused on high heat, energy-intensive processes in specific industries, such as iron and steel, cement, and refining, especially since iron and steel and cement account for over half of global GHG emissions from industry [117]. While these industries and the energy-intensive processes within them are key targets for decarbonization, there is untapped potential in many of the industries with low to medium temperature heat demand. The spectrum of industrial process heat demand by temperature of heat differs among regions of the world according to the composition of industries and their technologies. Table 3-1 shows the breakdown of IPH demand by temperature range for the global average, for the European Union (EU), and the United States. Notably, the percentage of high temperature heat, greater than 500°C, in the U.S. is smaller than other regions in the world. U.S. industries, such as chemicals, pulp and paper, and food, which have lower temperature IPH demand, make up a more significant share of manufacturing energy use.

Table 3-1. Comparison of industrial process heat demands by temperature range

Global [118]		**EU [119]**		**United States (this work)**	
Temperature Range	**Percentage of IPH Demand**	**Temperature Range**	**Percentage of IPH Demand**	**Temperature Range**	**Percentage of IPH Demand**
< 150°C	30%	< 100°C	14%	< 100°C	33%
150° - 400°C	22%	100–500°C	24%	100–500°C	44%
>400°C	48%	500–1,000°C	23%	500–1,000°C	13%
		> 1,000°C	39%	> 1,000°C	9%

In evaluating the potential for SIPH to meet industrial process heat demand, this work analyzes seven SIPH technologies:

- Flat plate collectors (FPC) with hot water storage
- Parabolic trough collectors (PTC) with and without thermal energy storage
- Linear Fresnel (LF) direct steam generation (DSG) collectors without storage
- PV-connected electric boiler
- PV-connected ambient heat pumps (PVHP) with hot water storage
- PV-connected waste heat recovery heat pumps (WHRHP)
- PV-connected resistance heating

The inclusion of PV-connected electrotechnologies, or electric heat technologies, extends current SIPH research to date, which typically focuses on solar thermal technologies. Analyzing PV-connected process heating contributes to ongoing analysis of industrial electrification sector [120], [121] that has been identified as one of the major pathways for reducing GHG emissions in industry [122]–[124]. Although not common in practice, this analysis assumes PV is installed onsite or near industrial sites, and implications for non-continuous electricity supply are discussed.

The scope of this analysis is IPH energy use in the U.S. manufacturing sector based on data for the base year 2014. The technical potential is quantified on a county-aggregated level, but not at the level of individual facilities. First, IPH demands are determined by end-use (conventional boiler, combined heat and power (CHP), and process heating) and temperatures. Second, solar technology system modeling is conducted for the seven SIPH technologies and their associated scenarios, with and without TES. Third, unit process analysis is used to match IPH demand to SIPH technologies. Fourth, the technical potential is quantified to identify opportunities for SIPH within industrial subsectors and by location. Lastly, an economic process parity analysis provides insights on cost drivers for SIPH to be competitive with conventional technologies.

3.2 Methods

3.2.1 County-level Process Heat Demand

The first part of the analysis expands previous work estimating industrial energy use at the facility-level [11], [32] and county-level [125]. Previous estimates were developed to fill spatial and operational data gaps, where established sources of energy data, such as the U.S. Department of Energy (DOE) Manufacturing Energy Consumption Survey (MECS) [126] and the State Energy Data System [127], fall short. Providing additional levels of spatial and operational detail is crucial for modeling the potential of solar technologies. The most significant advancements from previous research are the improved the use of facility-level data from the Environmental Protection Agency's (EPA's) Greenhouse Gas Reporting Program (GHGRP) by partitioning energy calculations based on the emissions reporting method, which allows for the collection of fuel-level information and combustion unit information. Additionally, estimations of industrial energy use account for process temperatures based on data in Brown, Hamel, and Hedman (1997). A schematic showing the process of estimating IPH demand and data sources used is provided in Appendix A.

Overall, this analysis provides the highest resolution estimates of combustion fuel use for IPH demand in the US. Figure 3-1 shows the total cumulative IPH demand by temperature and IPH end-use. About 50% (5,500 TBtu) of total IPH demand occurs at process temperatures below 300^{o}C, which is a result of the large contributions of hot water and steam demand from boilers. IPH demand above 400^{o}C are related to kilns, furnaces, and other process units that rely on the combustion of fuels.

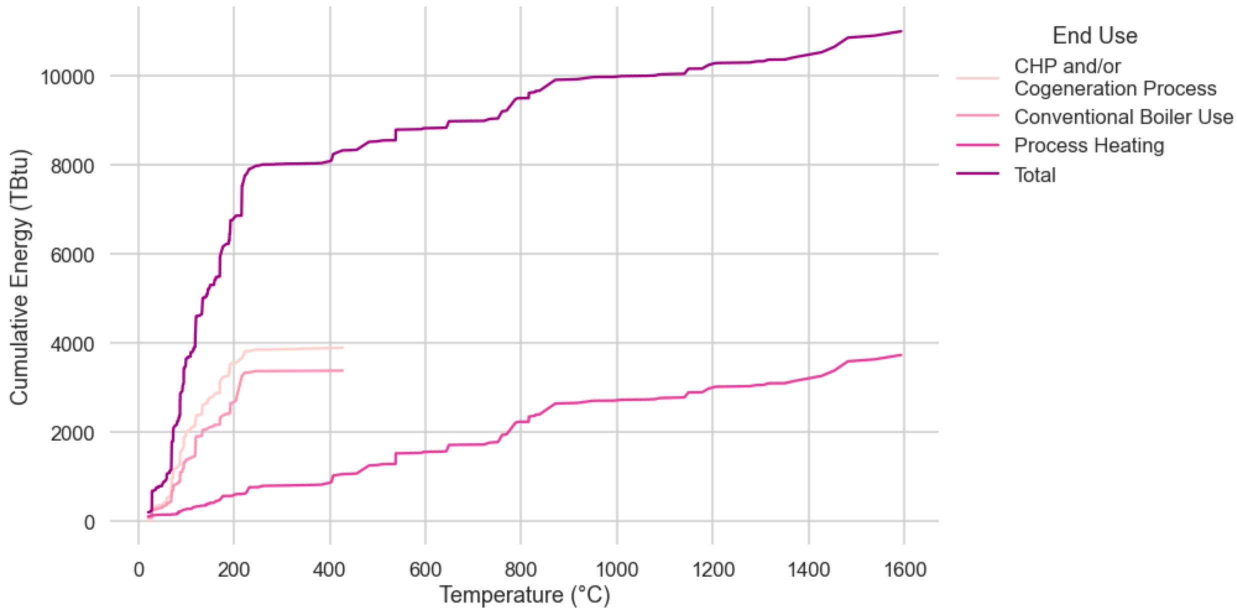


Figure 3-1. Cumulative industrial process heat demand by end-use category in 2014

Figure 3-2 shows a geographic distribution of IPH demand across most counties in the contiguous United States. On the map, the color of each county signifies a range of IPH energy use. The largest IPH energy use is concentrated in a few counties in Texas, Louisiana, California, and Indiana. The top five out of roughly 3,070 counties account for 12% of IPH demand, equivalent to the bottom 2,450 counties. These areas are generally home to clusters of energy-intensive industries, such as chemicals, petroleum refining, and, to a lesser extent, iron and steel. It is important to note, too, that counties with high IPH demand are located in all regions of the country – Northwest, Southwest, Gulf Coast, Midwest, Upper Midwest, Southeast, and Northeast. The mapping of solar resources and modeling of solar technology performance are discussed in the next section.

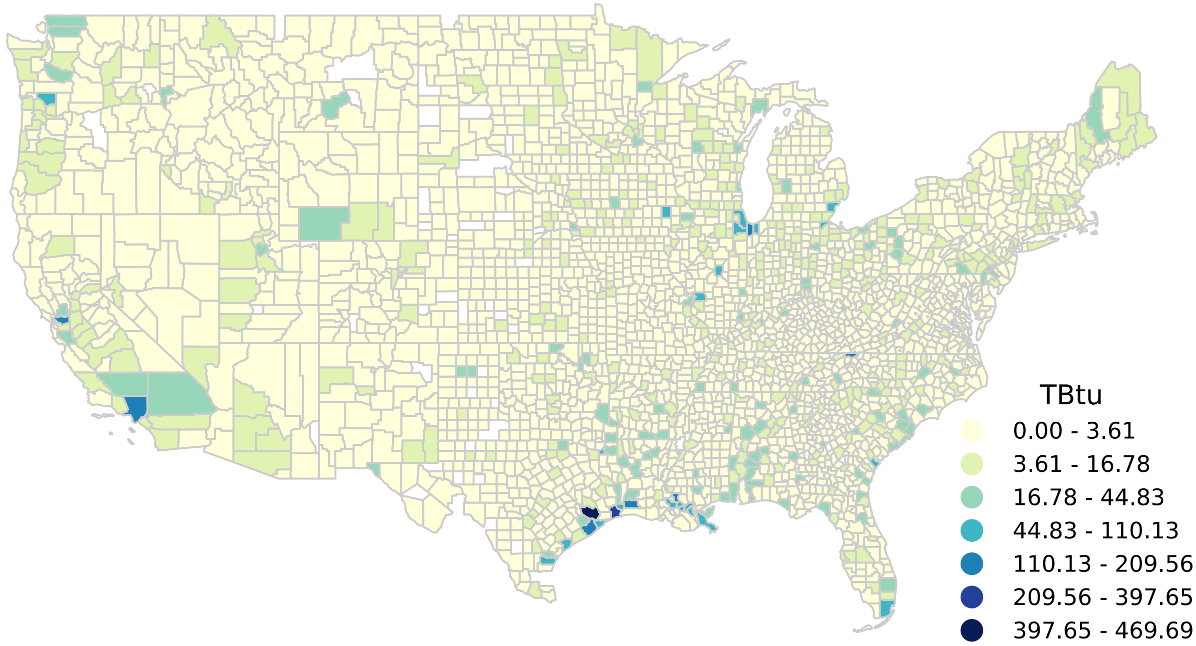


Figure 3-2. Geographic distribution of industrial process heat demand by county in 2014

Most of IPH energy demand is provided by natural gas (47%), as of 2014. Waste gas provides the next highest portion (20%), followed by biomass and coal as the primary fuel sources. Waste gases include refinery gas, coke oven gas, and blast furnace gas; biomass includes black liquor and other wood waste products from the pulp and paper industries. Table 3-2 shows the industries with the largest process heat demands alongside the temperature range that makes up most of the process heat within the industry. Several of these energy-intensive industries have a majority heat demand that is less than 100°C, making them ideal targets for SIPH technologies.

Table 3-2. Largest users of process heat and their largest temperature demands in 2014

NAICS	Industry	Total Process Heat Demand (TBtu)	Temperature Range of Largest Process Heat Demand Temperature (°C)	Heat Demand within Temperature Range (TBtu)	Process Temperature Percentage of Industry Total Process Heat Demand
324110	Petroleum Refineries	2,210	100–300	1,380	63%
322121	Paper (except Newsprint) Mills	870	<100	643	74%

322130	Paperboard Mills	803	<100	608	76%
331110	Iron and Steel Manufacturing	601	>1,000	313	52%
325199	Basic Chemical Products	593	100–300	281	47%
325193	Ethyl Alcohol Manufacturing	526	100–300	202	38%
322110	Pulp Mills	489	<100	367	75%

Not only are process temperatures key data inputs for modeling SIPH potential, but industrial operating schedules are also important factors. Load profiles of process heat are used in less than half of identified SIPH case studies [26]. Given the lack of publicly available load profile data, for this analysis, representative load curves are estimated by North American Industry Classification System (NAICS) code, employment size class, and end-use category for every hour in 2014. These estimated load curves consider average weekly operating hours published by quarter by the U.S. Census Bureau, seasonality, facility size, and an assumed equipment turndown ratio (the ratio of maximum capacity to minimum capacity for equipment during non-operating hours) for boilers and process heating equipment.

3.2.2 Solar Heat Generation

Solar resources are often represented by direct normal irradiance (DNI) and global horizontal irradiance (GHI), measures of solar radiation hitting the earth directly, as with DNI, or hitting directly as well as capturing reflected light, as with GHI. There is wide variation of both DNI and GHI across the U.S. [129]. For GHI, the range is 1,000-2,500 kWh/m^2/year; for DNI, it is 1,450-2,740 kWh/m^2/year [129]. Figure 3-3 shows maps of the annualized daily mean for GHI and DNI in the US. GHI is important for computing PV outputs, whereas DNI is important for concentrating solar power (CSP).

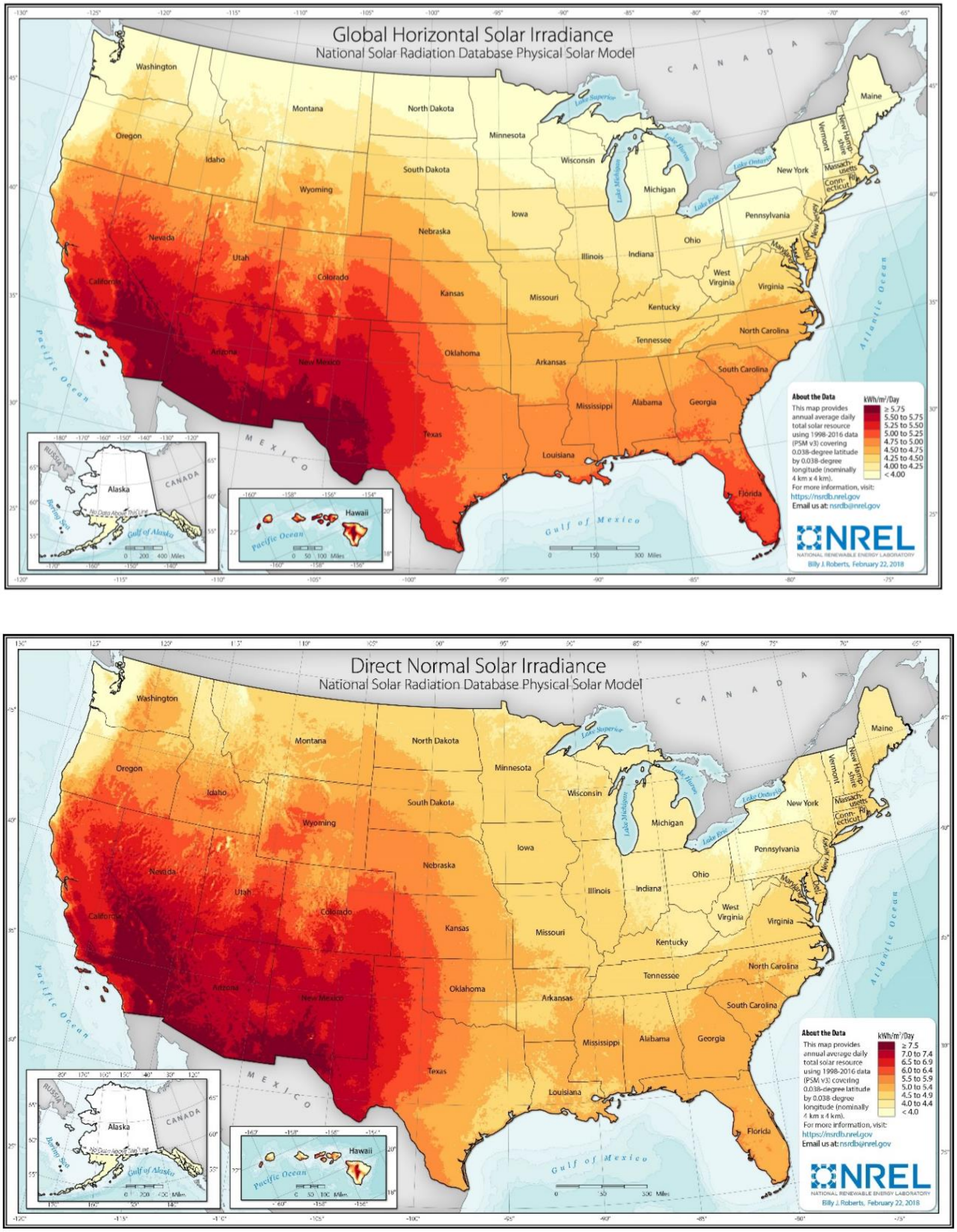


Figure 3-3. Maps of the mean solar resource availability to PV systems (top) and CSP (bottom) in the U.S. [129].

For CSP for electricity generation to be economically feasible, DNI needs to be more than 2,000 kWh/m^2/year, which is more than 5.0 kWh/m^2/day; for concentrating solar thermal, DNI can be slightly less [130]. Much of the U.S. has sufficient resources for solar thermal to meet process heat needs. To characterize SIPH potential, in addition to solar resources, it is necessary to consider the available land for solar installations. Many land use and land policy criteria prohibit areas from becoming viable installation sites. The exclusion criteria for land area include slope (generally, >3% is excluded), urban areas, land cover (e.g., open water, forests), federal lands, airports, protected areas, and national conservation areas. Rooftop area on existing buildings is also excluded in this analysis. The full description of exclusion criteria is listed in Appendix A.

For the seven SIPH technologies selected for this analysis, NREL's System Advisor Model (SAM) is used to model hourly energy delivered by the technology at the process directly or at the point of a heat exchanger. SAM is a techno-economic computer model developed and is distributed by NREL that calculates performance and financial metrics of renewable energy projects [131]. For this analysis, SAM is used to determine solar technology energy production given the weather characteristics at a given location for the year 2014. The Renewable Energy Potential Model (reV), a spatiotemporal modeling assessment tool that calculates renewable energy capacity, generation, and cost based on geospatial intersection with grid infrastructure and land-use characteristics, also developed by NREL, is used to automate solar radiation data, execute the SAM models, and compile output data for all counties in the continental US. Table 3-3 shows the technology system inputs for the SAM model.

Table 3-3. SIPH technology packages used in SAM to create the system representations for high performance computer modeling

Technology Package	**MW_{th} of Solar Field**	**MW_{th} at the Heat Exchanger**	**HTF**	**Volume of TES/Hours of Storage**	**Collector/Type**	**Total Land Area**	**Aperture Area/ Absorption Area (m^2)**
Solar water heating-FPC	1.0	~1.27	Glycol	60 m^3	Heliodyne Gobi 410 001	~0.5 acres	2,014 m^2
CSP: oil trough, no TES	1.5	1.00	Therminol-VP-1	0	SkyFuel SkyTrough	~2 acres/ ~8,094 m^2	2,624 m^2
CSP: oil trough, 6 hours of TES	2.5	1.00	Therminol-VP-1	6 hours	SkyFuel SkyTrough	~4 acres/ ~16,187 m^2	5,248 m^2
CSP with DSG LF collector, no TES	1.2	1.00	Water/Steam mix	0	Novatec	~1 acre/ ~3,698 m^2	3,082 m^2
PV DC for connection to resistive heater[a]	1.2	NA	NA	NA	Standard module from PVWATTs Calculator with fixed open rack	In SAM output	In SAM output

[a] For PV AC, the same solar field is used, but 1MWe is used as the system size.

3.2.3 Matching SIPH Technologies to Industrial Processes

As mentioned in the introduction of this chapter, there are seven SIPH technologies evaluated in this study. A variety of solar thermal collectors are selected based on their differences in temperature ranges, costs, and current applications. With solar PV, selecting associated electric heat technologies is more complex because there are numerous electrotechnologies, relying on different operating principles and with differences in their potential to electrify industrial process heat. Based on a thorough literature review of electrotechnologies, 14 are identified as feasible options for process heating, and a screening exercise is conducted to down select a few for analysis in this research. The screening criteria considers 1) estimated technical potential for the electrotechnology to replace conventional fuel use, 2) data availability of technology characteristics, and 3) market growth outlook. From this exercise, ambient heat pumps, electric boilers, resistance heating, and waste heat recovery heat pumps are selected. The scoring of the screening process is listed in Appendix A.

The integration of SIPH systems in existing manufacturing facilities is an important factor for determining their technical potential. To this end, technology constraints are defined for each solar technology system. The descriptions of the solar technology packages and their generation potentials are discussed in the prior section, but the method for determining which SIPH technology is applicable to certain portions of process heat demands is introduced here.

Solar thermal technologies provide heat in the form of hot water, steam, or other heat transfer fluids (HTFs), whereas solar PV provides electricity. In addition to the type of heat supplied, solar thermal and electric technologies differ in achievable temperature ranges, and the types of unit processes for which they are technically feasible. For example, an FPC is used in hot water heating and, therefore, would only be able to meet heat demands for industries and unit processes that require hot water. In another example, an electric resistance heater can theoretically supply low to very high temperature heat, but because of the commercial availability of the technology, it is limited to the unit processes for which commercially available or demonstrated technologies exist. This method for cross-checking characteristics of solar generated heat and applicable heat demand provides a specific portion of process heat demand for each solar technology package. Matching solar heat technologies to process heat demand accounts for their achievable heat supply temperatures, medium of heat energy, and, in some cases, examples of their commercial use for certain unit processes. The complete list of characteristics and limiting parameters is included in Appendix A. Figure 3-4 shows a high-level summary of the SIPH technologies matched to a portion of IPH demand.

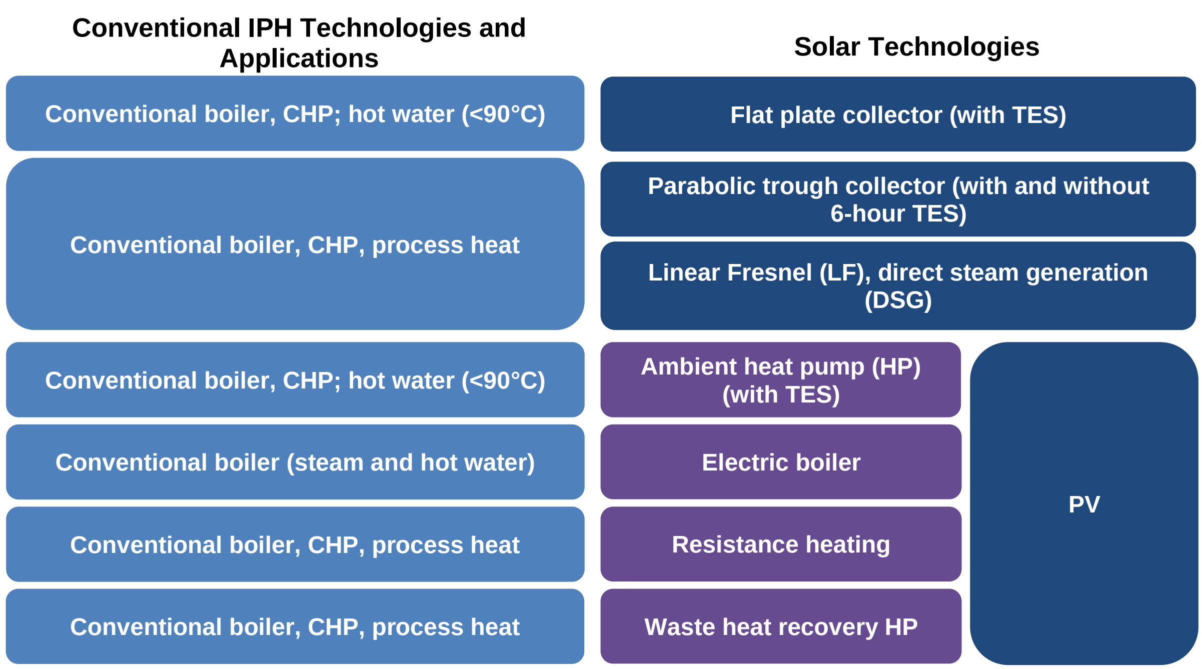


Figure 3-4. Applications of industrial process heat matched to solar technologies. These represent the seven SIPH systems analyzed in this work.

3.2.4 Quantification of Technical Potential

Typically, technical potential is defined as a renewable energy's generation potential given system, topographic, and land-use constraints and system performance [132]. Technical potential sits second among a progression of renewable energy potential levels, beginning with resource potential and followed by economic potential and market potential [132]. Here, technical potential is extended beyond a singular calculation to account for energy potential on an hourly scale over the course of one year. To compare the solar heat supply and process heat demand for which it is feasible, a solar fraction, which is defined as the contribution of solar energy to the total heat load, is calculated. The solar fraction is calculated for every county in the US, and for every hour of the year. Using this value, the opportunity for a SIPH technology can be described in terms of location, time of year, and industry.

Since IPH demand varies by process temperature, fuel type, end-use, and hours of operation, it is useful to characterize process heat demand at the level of the unit process requiring heat. As described in Section 3.2.1, county-level fuel use for IPH is categorized by fuel use (energy content and fuel type), but the physical heat delivered to a unit process is often in the form of steam or hot water and contains less energy because of efficiency losses from the fuel combustion step. The process-level heat demand from conventional heating must be known to determine the potential for solar generated heat, so that the thermal energy required for the process is equivalent.

Figure 3-5 depicts the steps for comparing process heat demand to process heat supplied by solar in order to calculate a solar fraction. On the demand side, these steps include using the count-level fuel estimates for IPH, apportioning the relevant share of IPH demand for each SIPH technology, accounting for efficiency losses in combustion technologies, and adjusting IPH demand based on load profiles. On the supply side, the solar resources are modeled in SAM and reV based on hourly weather data, and land availability by county is determined based on land exclusion criteria.

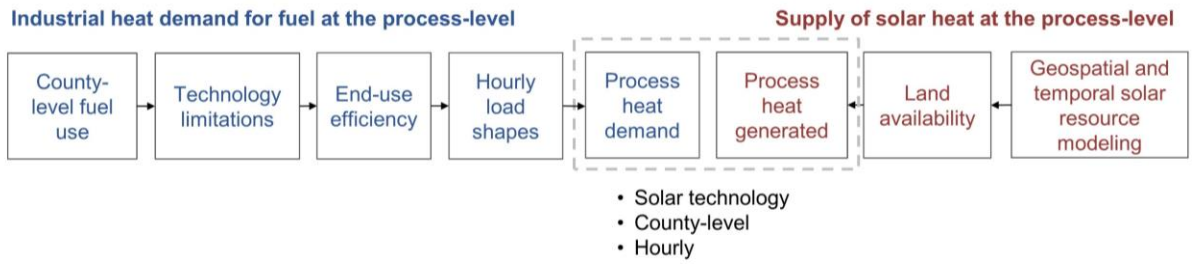


Figure 3-5. Method for matching process heat demand and process heat supply

As shown in Figure 3-4, for each solar technology covered in this study, a process-level heat demand is calculated from county-level fuel use, considering the end-uses relevant to the type of heat the solar technology provides as well as its technology limitations, such as achievable temperature range and potential within applicable industries. End-uses are based on the MECS reporting structure and include conventional boilers, CHP, and process heating. Figure 3-6 shows simple block diagrams of these end-uses. With each combustion unit, there is an efficiency loss between the primary energy associated with the fuel and the useful heat energy used by the process. The thermal efficiency of boilers changes with fuel type: CHP units have both a thermal and electrical efficiency that depend on the prime-mover type of units, and direct process heating has heat losses in combustion. The calculations for end-use efficiency and process-level heat demand are described in Appendix A.

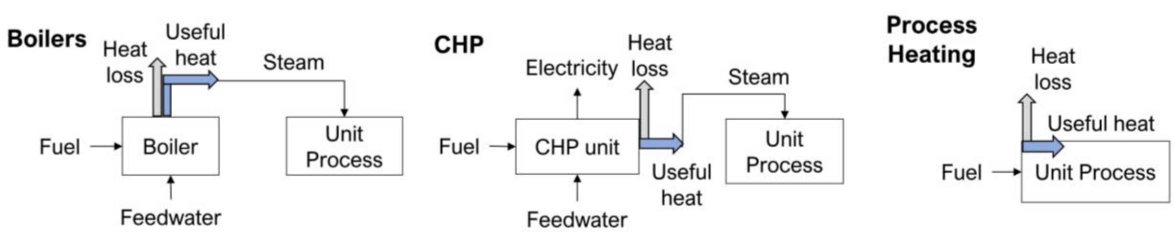


Figure 3-6. Block diagrams of the main end-use categories for industrial process heat

Once the process-level heat demand for each solar technology is calculated, the result is used to scale up the size of the base SIPH system such that it can meet the process heat demand for a particular county on either a June or December average. Solar technologies modeled in SAM and reV are designed to be a ~1MW base system. Scaling the solar technology packages based on December generation when U.S. meteorological conditions are at their worst for efficient thermal energy generation (i.e., low solar irradiance and ambient temperatures) results in larger systems. Conversely, sizing systems for summer peaks in June when irradiance is higher results in smaller systems, avoiding overproduction but risking underproduction in winter months.

3.2.5 Evaluation of Economic Process Parity

To understand the economic feasibility of IPH fuel switching, a process parity framework that identifies conditions when solar process heat technologies can reach cost parity with incumbent combustion technologies is developed. This process parity framework accounts for investment costs, O&M costs, and fuel prices, and consists of three sub-models: a technology model for capturing technical performance parameters, a levelized cost of heat (LCOH) model for calculating lifetime system costs, and a parity model for altering variables in the LCOH model to determine process parity.

The technology model is applied to a case study of a brewery, where three SIPH technologies are compared against a conventional natural gas boiler for steam generation. Breweries are a subset of the beverages industry, which used 0.5% of total manufacturing fuel use in the U.S. in 2014 [133]. Process heat demand is almost exclusively provided by natural gas-fired boilers and accounts for 42% of total beverage industry energy use [133]. As of 2018 there were 3,890 breweries in the US, with at least one in every state, the District of Columbia, and Puerto Rico [134]. Although the production process can vary from plant to plant, the model assumes a single archetype of process heat energy use for U.S. breweries and production capacity of 250,000 hectoliters per year. Further descriptions of technical parameters are included in [114]. Figure 3-7 shows a schematic of the three SIPH technologies under evaluation for replacing steam generation from a conventional natural gas boiler.

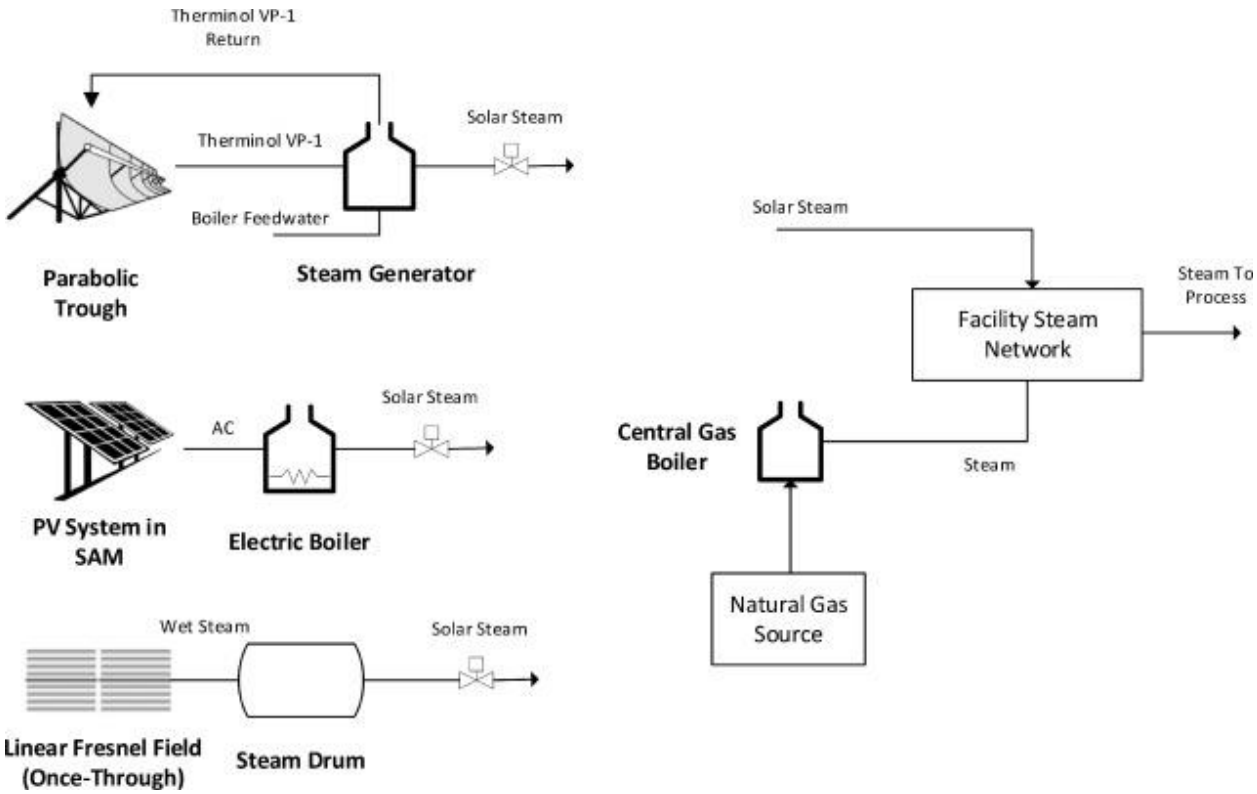


Figure 3-7. Solar heat integration scheme and existing natural gas boiler for the brewery case study

A modified LCOH equation from IEA Task 54 is defined in Equation 3-1 below, where where I_0 is the initial investment cost, S_0 are initial subsidies, C_t is the annualized cost (further defined in the SI), TR is the tax rate, DEP_t is the depreciation at year t, RV is the residual value, r is the discount rate, E_t is the energy delivered to the process and T is the period of analysis [135].

$$LCOH = \frac{I_0 - S_0 + \sum_{t=1}^{T} \frac{C_t(1-TR) - DEP_t \times TR}{(1+r)^t} - \frac{RV}{(1+r)^T}}{\sum_{t=1}^{T} \frac{E_t \times (1-TR)}{(1+r)^t}} \qquad (3\text{-}1)$$

The equation is in a modified form, in which E_t is reduced by the tax rate, TR, to account for the taxation of energy production. However, this change does not alter LCOH parity across different energy systems. Several non-energy cost benefits are included in the model, where data is available. These include emissions-related costs, permit related costs, and land area reduction estimations, but not all factors are applied in each technology case. Permit costs are applied only to the fuel combustion steam boiler, and floor space area reduction is applied to only the PV-electric boiler case [136].

3.3 Results and Discussion

3.3.1 County-level Technical Potential

A key factor of a solar technology's technical potential is its ability to provide the necessary heat load, reported here as the solar fraction. The following set of maps displays how often the solar fraction is greater than or equal to one, signifying that solar heat is fully meeting process heat demands. The maps, in Figure 3-8 and Figure 3-9, show the potential for solar heat technologies across the United States based on SIPH systems sized to meet peak load for the month of June. These figures capture the temporal and spatial aspects of SIPH technical potential, whereas the total magnitude of potential is discussed later.

With the LF and PTC cases, regional variation is more pronounced than with the FPC or electrotechnology cases. This result is due to the technology limitations associated with these solar thermal technologies; the process heat demand matched to LF and PTC systems was limited by the maximum temperatures of heat the systems could provide, compared to required process temperatures. The supplied temperature of these solar thermal systems decreases in colder months, concurrent with the decrease in ambient temperature. The ability to meet heat demand for the entire year is reduced in northern parts of the country as a result.

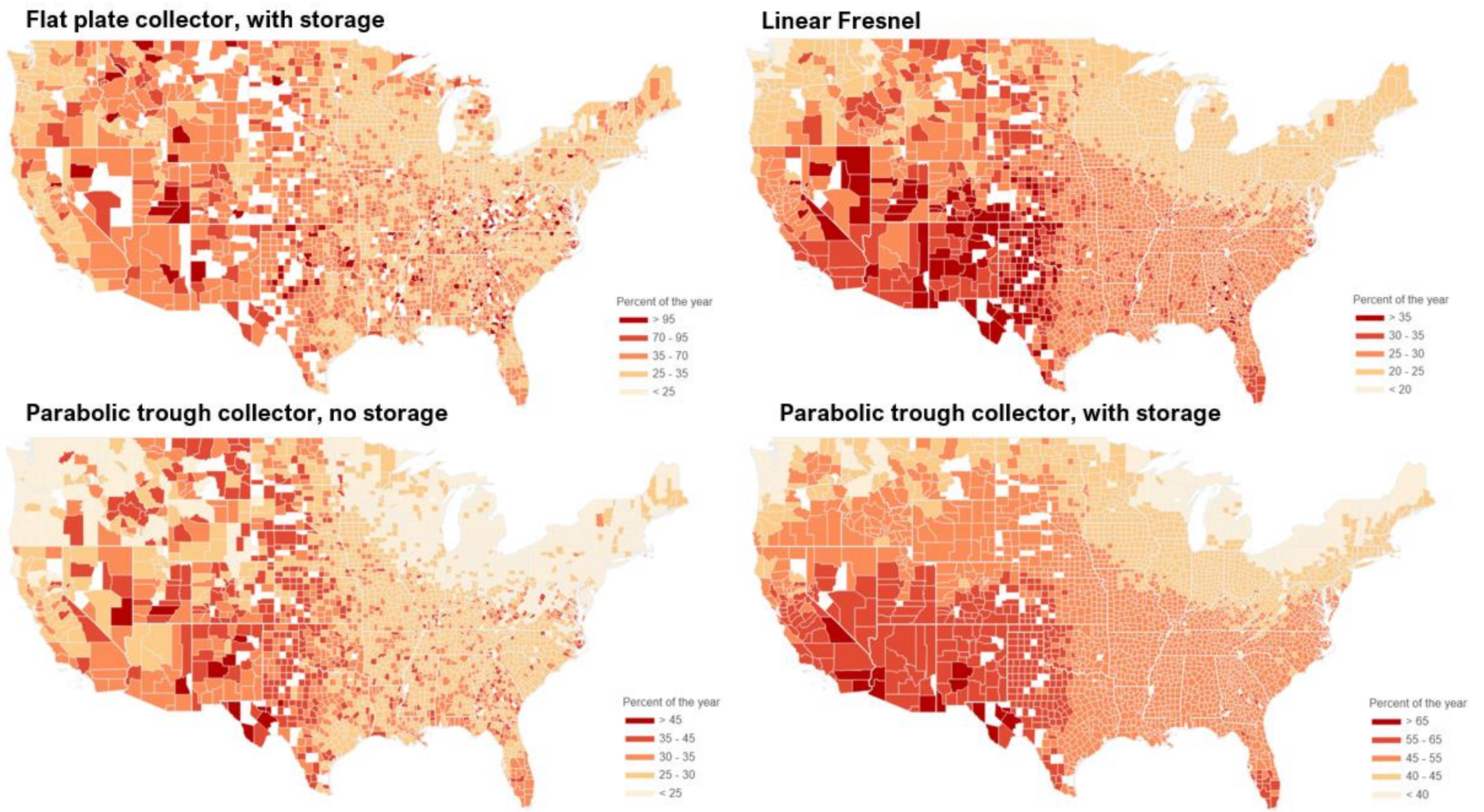


Figure 3-8. County-level maps showing the percentage of the year when solar heat is fully meeting process heat demand using solar thermal technologies (FPCs, LF DSG, PTC with TES, and PTC without TES) sized to peak summer demand. Counties colored white have no relevant IPH demand for the solar technology.

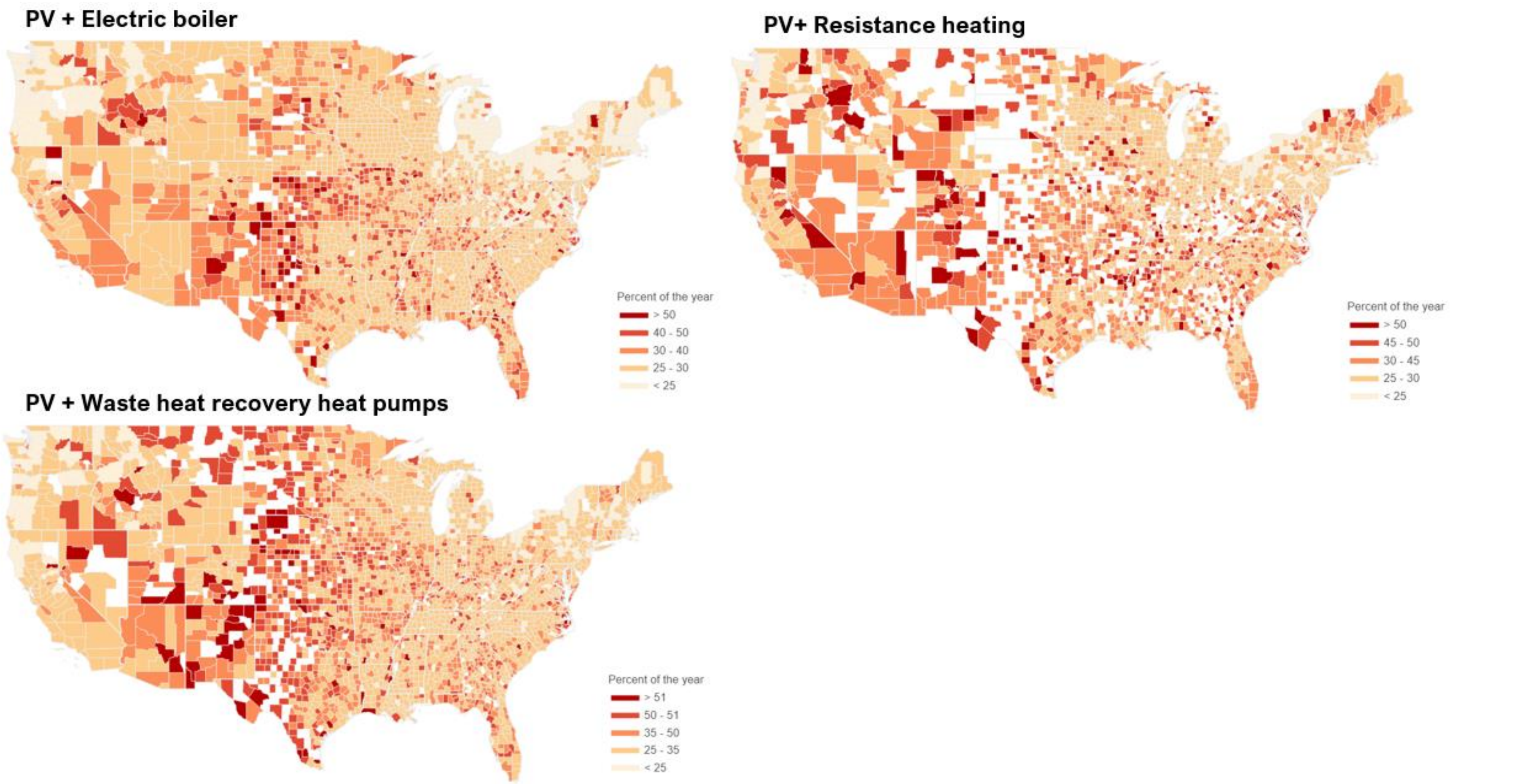


Figure 3-9. County-level maps showing the percentage of the year when solar heat is fully meeting demand using PV-based electrotechnologies (E-boiler, resistance heating and WHRHPs) sized to peak summer demand. Counties colored white have no relevant IPH demand for the solar technology.

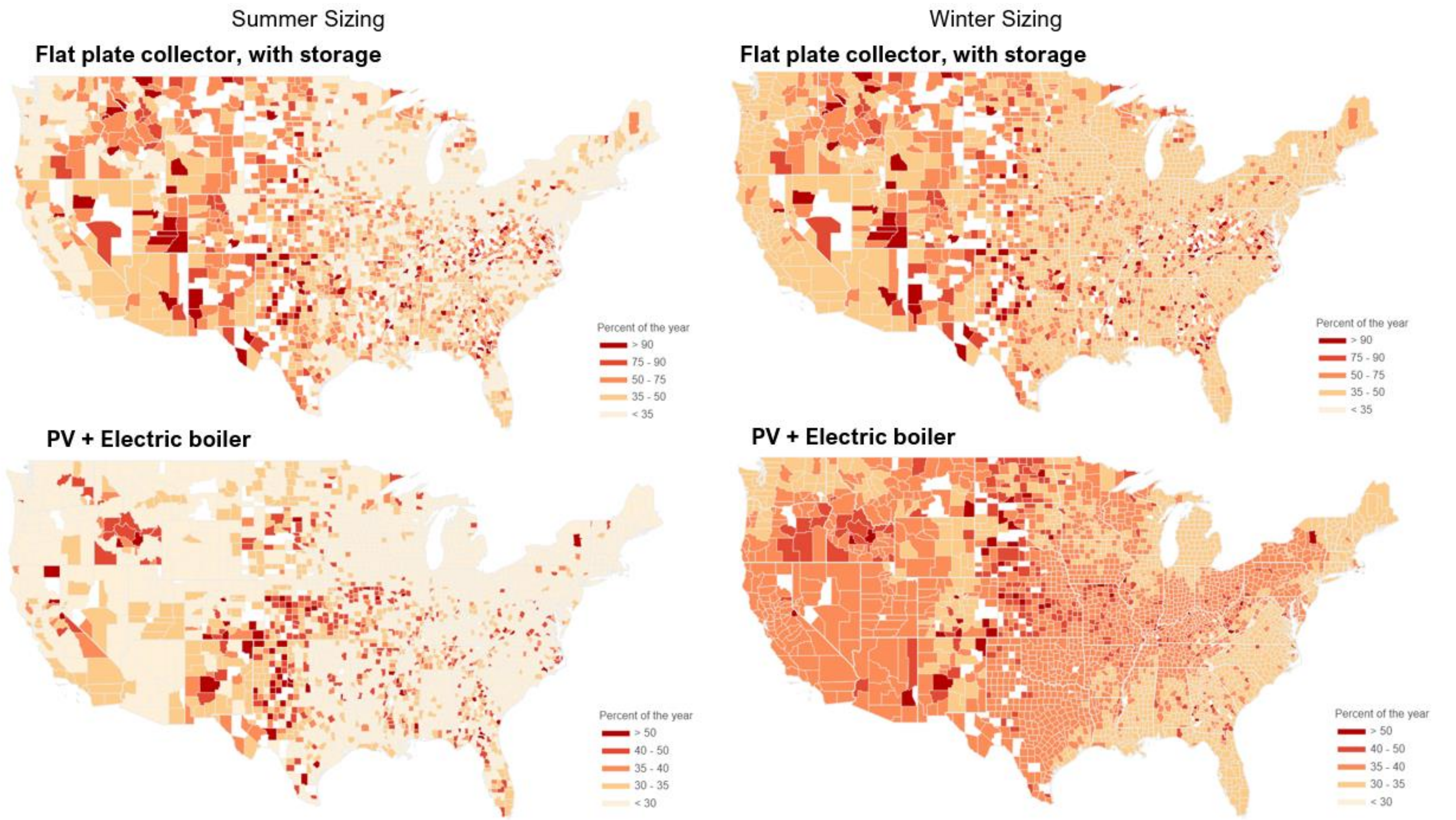


Figure 3-10. County-level maps showing the percentage of the year when solar heat fully meets demand for the FPC and E-boiler cases, comparing summer- and winter-sized systems. Counties colored white have no relevant IPH demand for the solar technology.

Although results in Figure 3-8 and Figure 3-9 are based on SIPH systems sized for summer; a system sized for winter accounts for decreased solar irradiance in parts of the country and is consequently larger, leading to high solar fractions more frequently throughout the year. A comparison of summer- and winter-sized systems for the FPC and E-boiler case is shown in Figure 3-10. With winter sizing, solar can fully meet demand for more than half the year for 82% of counties, compared to 34% of counties with summer sizing. Although winter-sized systems present a higher technical opportunity, their larger size leads to increased costs, and further economic analysis would be needed to determine their suitability. For all solar technology packages, winter-sized systems result in solar heat meeting demand more often (Figure 3-11). Among the different technologies, FPC has the highest frequency of meeting demand on average. Different storage assumptions were used in the PVHP modeling and, as a result, the results show the PVHP meeting IPH demands at all hours throughout the year.

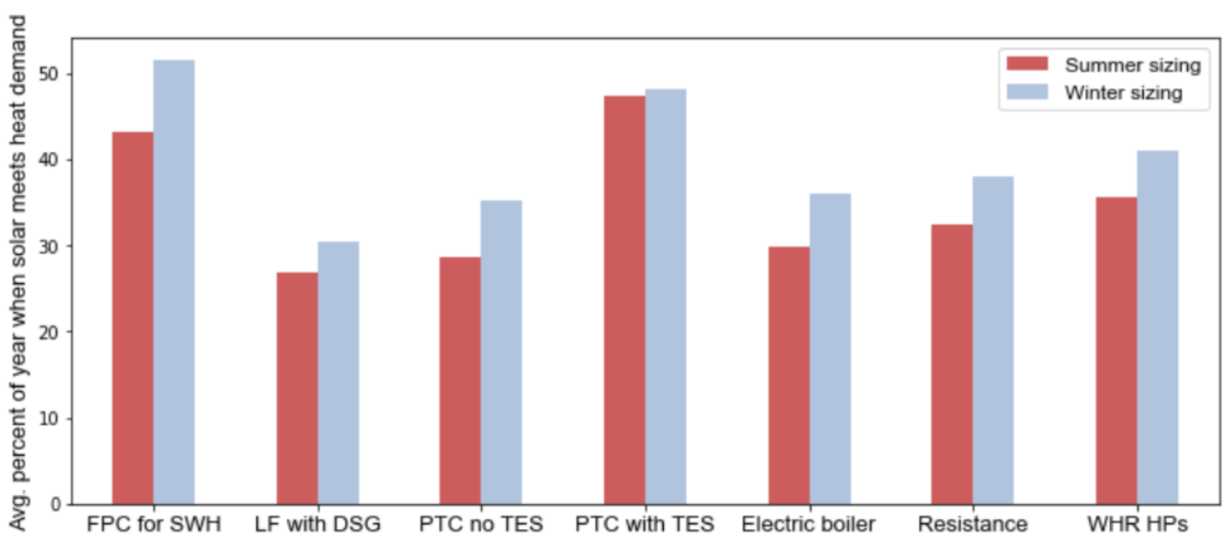


Figure 3-11. Average frequency (percentage of the year) that solar heat fully meets demand

Figure 3-12 compares the solar technologies by combining the spatial and temporal dimensions of their technical opportunity. Technologies in the top right of the chart meet demand for a larger percentage of the year and for a greater number of counties. A noticeable difference between the two PTC cases demonstrates that the presence of TES is significant and largely impacts the frequency and distribution of meeting demand.

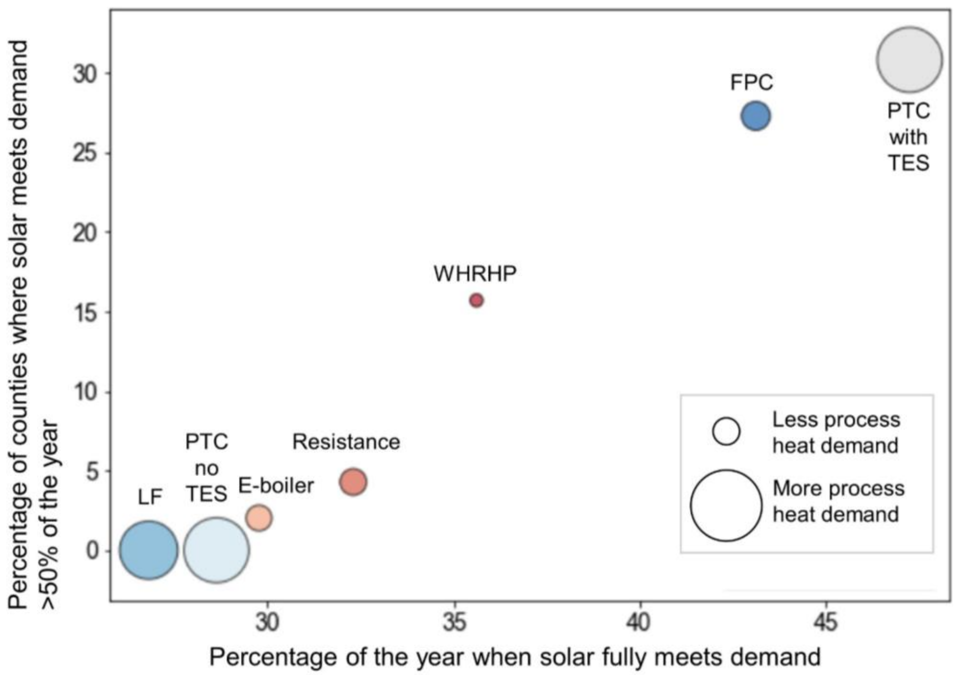


Figure 3-12. Comparison of SIPH technologies, sized to summer peak IPH demand. The size of the bubble corresponds to technology's process heat demand. The color of the bubble is used to distinguish the technologies.

3.3.2 Industrial Subsector Technical Potential

The technical opportunity of solar technologies can also be evaluated by their potential to supply heat within industrial subsectors. The solar heat potentials (Figure 3-13) represent the total amounts of heat these solar technologies can provide in a year based on a summation of their hourly solar fractions. The solar heat potentials are annual totals for several key subsectors.

The largest overall opportunity for SIPH occurs in the chemicals subsector, followed by the pulp and paper subsector. Both subsectors have large IPH demands that are met by CHP and conventional boilers; however, IPH demands below 100°C in the pulp and paper industry were characterized exclusively as steam, which explains the lack of opportunities for FPC, which were defined only for hot water IPH demands. The chemicals subsector is more diverse in terms of its use of hot water, however, and opportunities for FPC on the order of about 350 TBtu were identified. Opportunities for PV+resistance heating of roughly the same magnitude occur in the metals, chemicals, food, and petroleum and coal products subsectors. As expected, opportunities for WHRHPs are the smallest, and they are concentrated in the pulp and paper, petroleum and coal products, and chemicals subsectors.

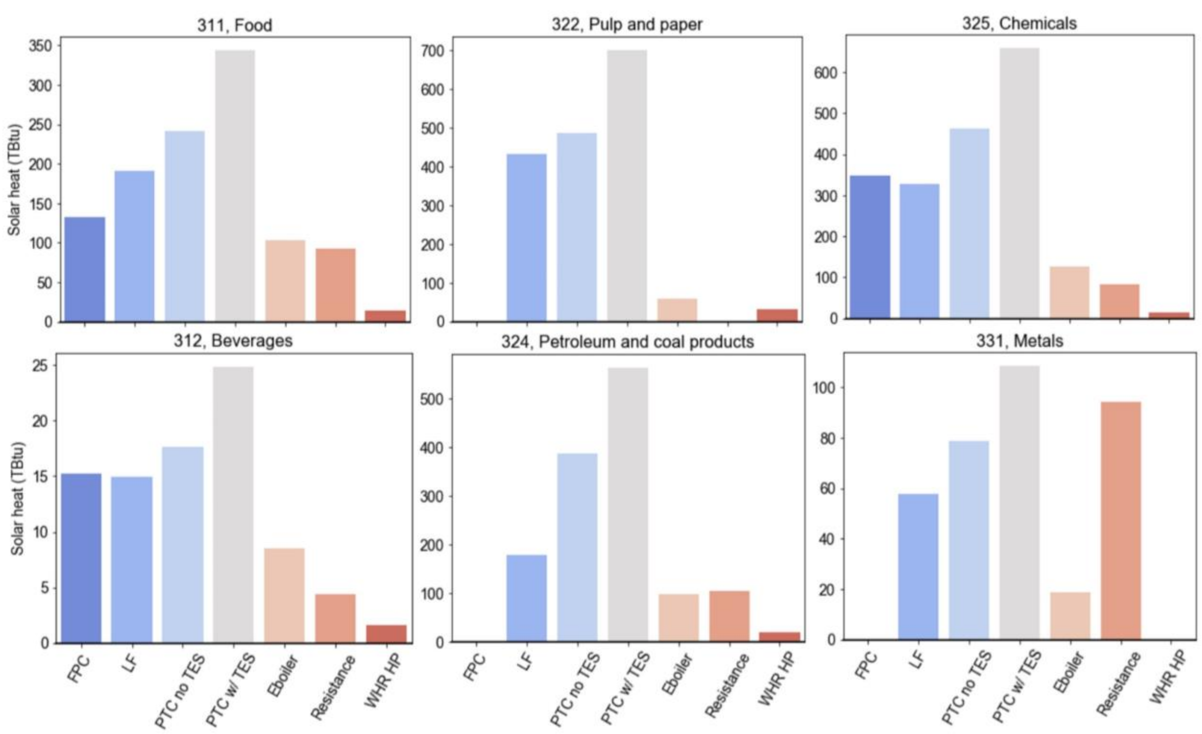


Figure 3-13. Annual solar heat potential (TBtu) for high heat demand subsectors

3.3.3 Temporal Variation

To illustrate the effects of hourly and monthly variation in SIPH potential and the significance of TES, Figure 3-14 displays a heat map of the solar fraction for the two PTC cases in Polk County, Iowa: PTC without TES and PTC with 6 hours of storage. The heat map shows the hours of the day on the y-axis and the months of the year on the x-axis, with each internal square representing the solar fraction at a specific hour of the day averaged for each month; these values are displayed in the squares. The solar fraction of PTC with TES is greater than one for 28% more of the time than PTC without it.

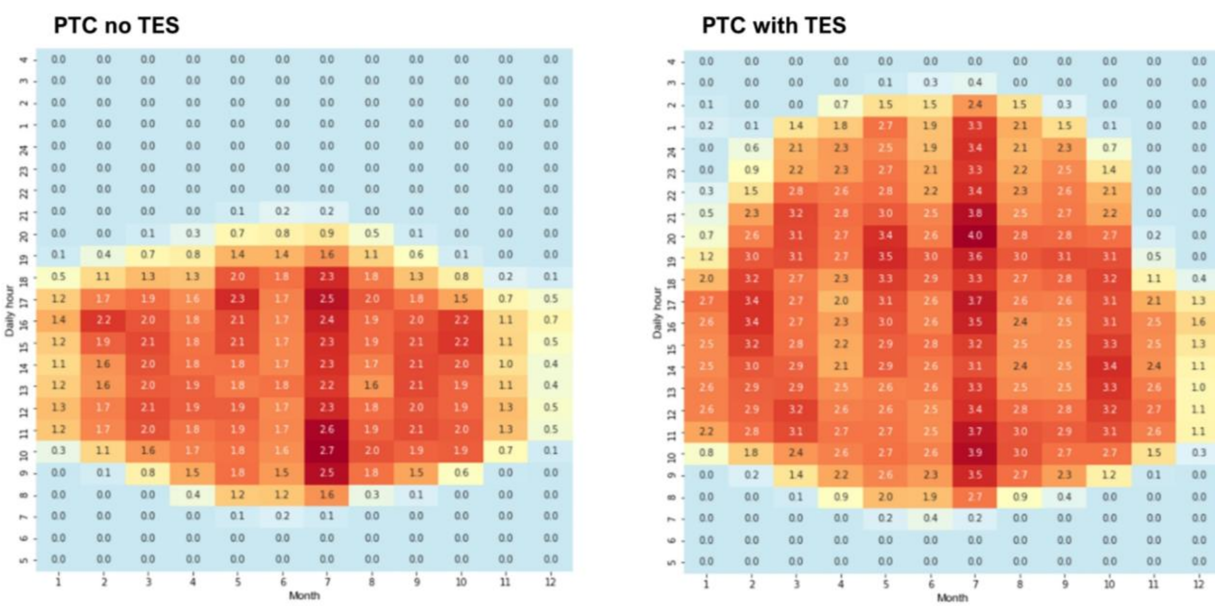


Figure 3-14. Heat maps of the two PTC cases showing the solar fraction for hour of the day and the month of year for Polk County, Iowa

3.3.4 Fuel Use and Emissions Impacts

With the potential to meet heat demand during a substantial portion of the year, solar heat technologies can provide significant reductions in conventional fuel use, which can lead to avoided combustion emissions. The amounts of fuel savings are calculated based on hourly solar fractions for each county and by fuel type. Figure 3-15 shows the total annual fuel savings by fuel type for each technology package, and Figure 3-16 shows the monthly fuel savings by fuel type for each solar technology, both with summer peak IPH demand sizing.

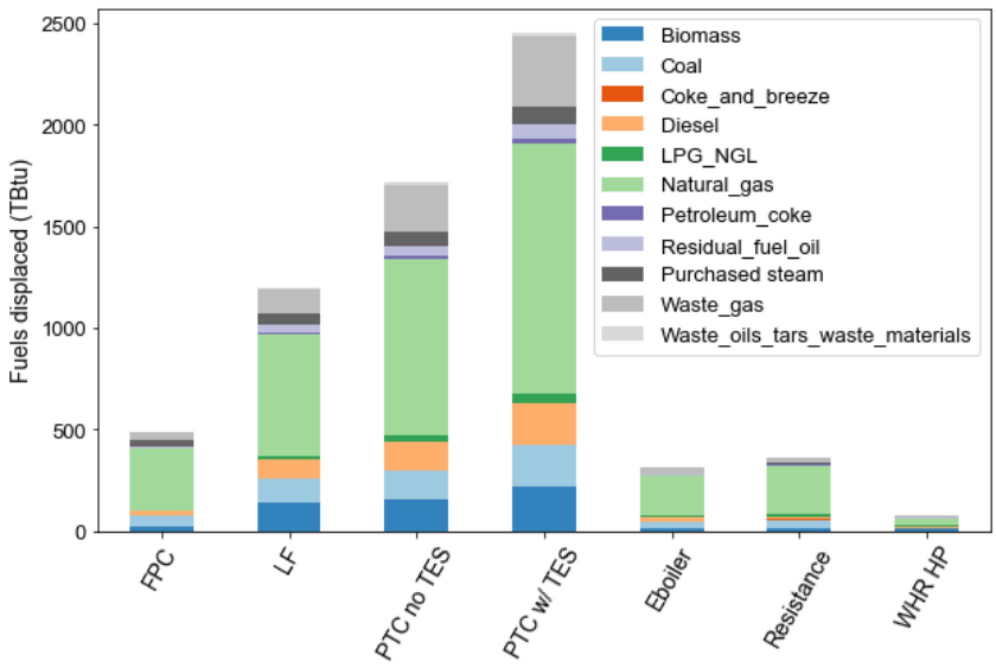


Figure 3-15. Total fuels displaced for each solar technology (in TBtu/year)

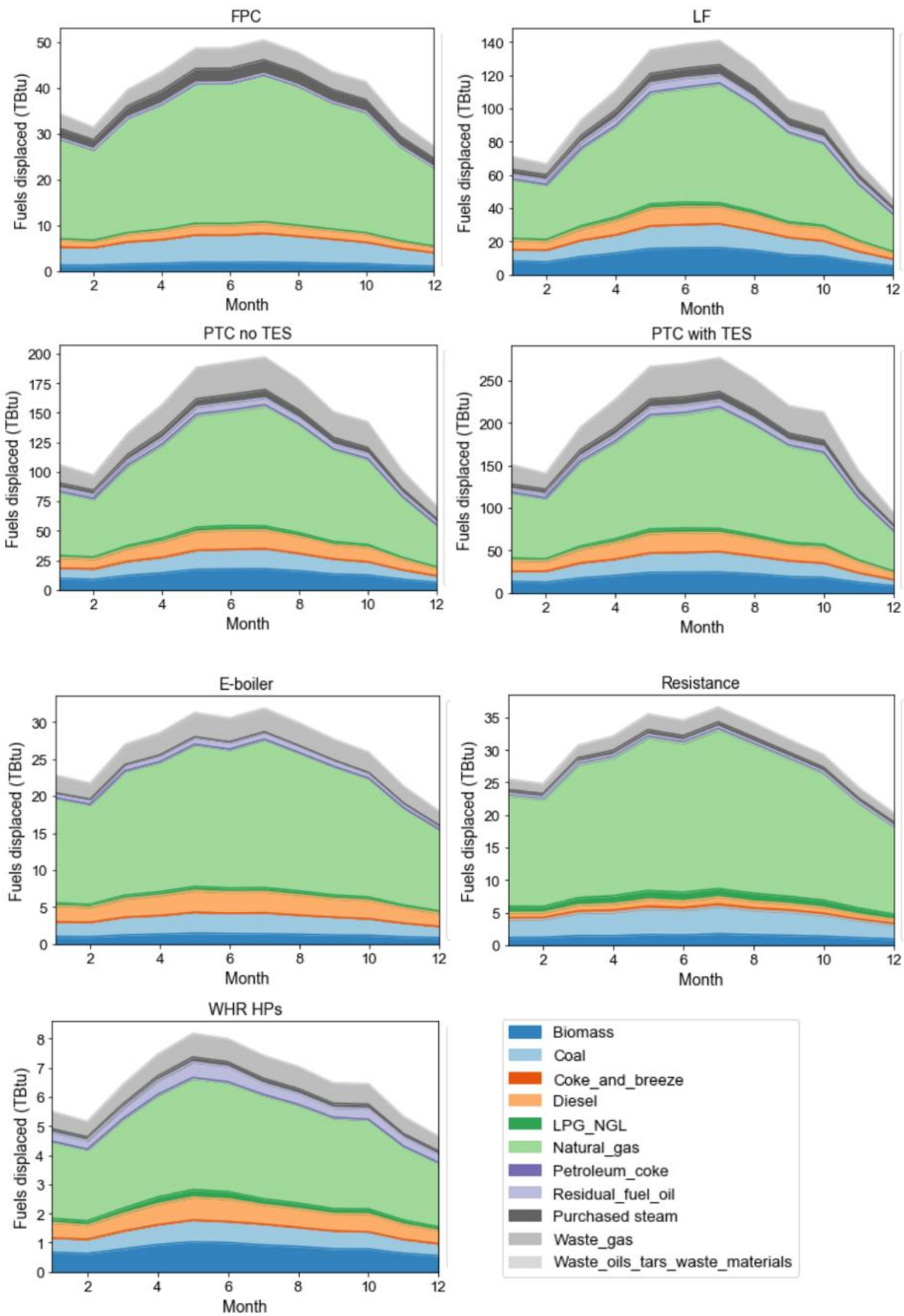


Figure 3-16. Monthly fuel displaced by solar technologies (in TBtu/month)

Across all SIPH systems, the predominant fuel that is replaced is natural gas, given its abundant use in U.S. IPH energy use. There are also high potential savings with coal and diesel, and in some cases biomass. While coal and diesel are purchased fuels, biomass can be an in-plant byproduct within the forest product industries; therefore, finding another end use could present a practical challenge or potential opportunity for such facilities. In the summer months, the potential fuel savings are highest because solar irradiance is increased in more parts of the county, leading to greater frequencies of high solar fractions.

The total amount of carbon dioxide emissions avoided due to fuel savings for each solar technology is shown in Table 3-4. Carbon dioxide emissions were calculated based on fuel savings described previously and emissions factors taken from EPA data on stationary combustion [137]. The carbon dioxide emissions calculated from combined fuel use are listed as totals for each technology. In 2014, U.S. carbon dioxide emissions from industrial fossil fuel combustion were about 891.6 million metric tons [46]. In relative terms the technology with the smallest potential, WHRHPs, represents an avoidance of about 0.5% of total industrial combustion emissions. The technology with the largest opportunity, PTC with TES, represents about 15% of total industrial combustion emissions of CO_2.

Table 3-4. Carbon dioxide emissions avoided (in million metric tons)

	FPC	**LF DSG**	**PTC no TES**	**PTC w/ TES**	**E-boiler**	**Resistance**	**WHRHP**
Summer sizing	26.6	70.3	95.8	136.4	18.3	20.9	4.7
Winter sizing	32.2	75.4	106.2	137.4	18.1	18.7	5.3

3.3.5 Land Use

The area of land required for each SIPH system was scaled to meet peak load during the months of June or December, and the results of land use totaled and by county for summer sizing are shown in Figure 3-17 and Figure 3-18.

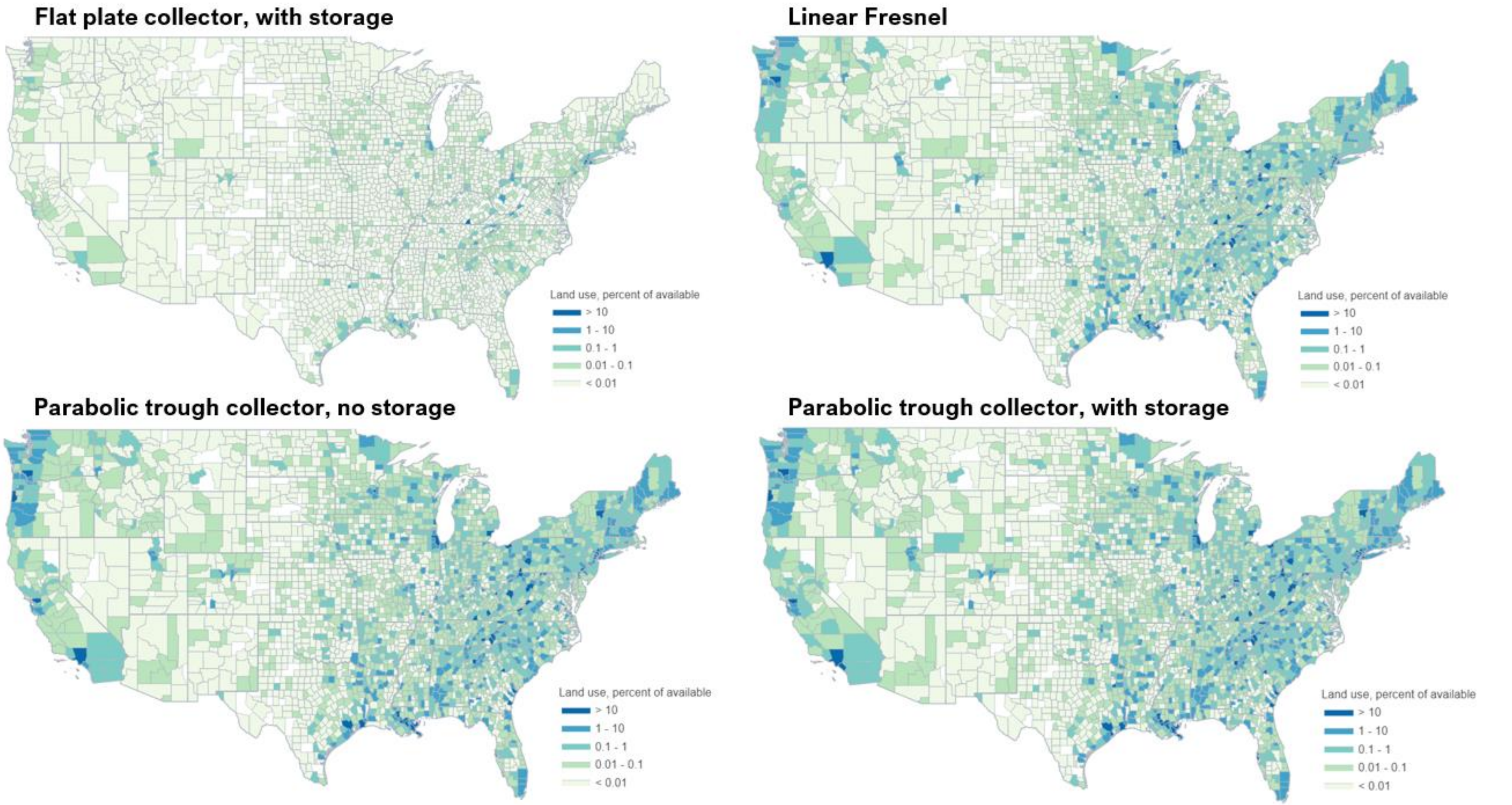


Figure 3-17. County-level maps showing land use as a percentage of the available land for ST technologies, summer sizing

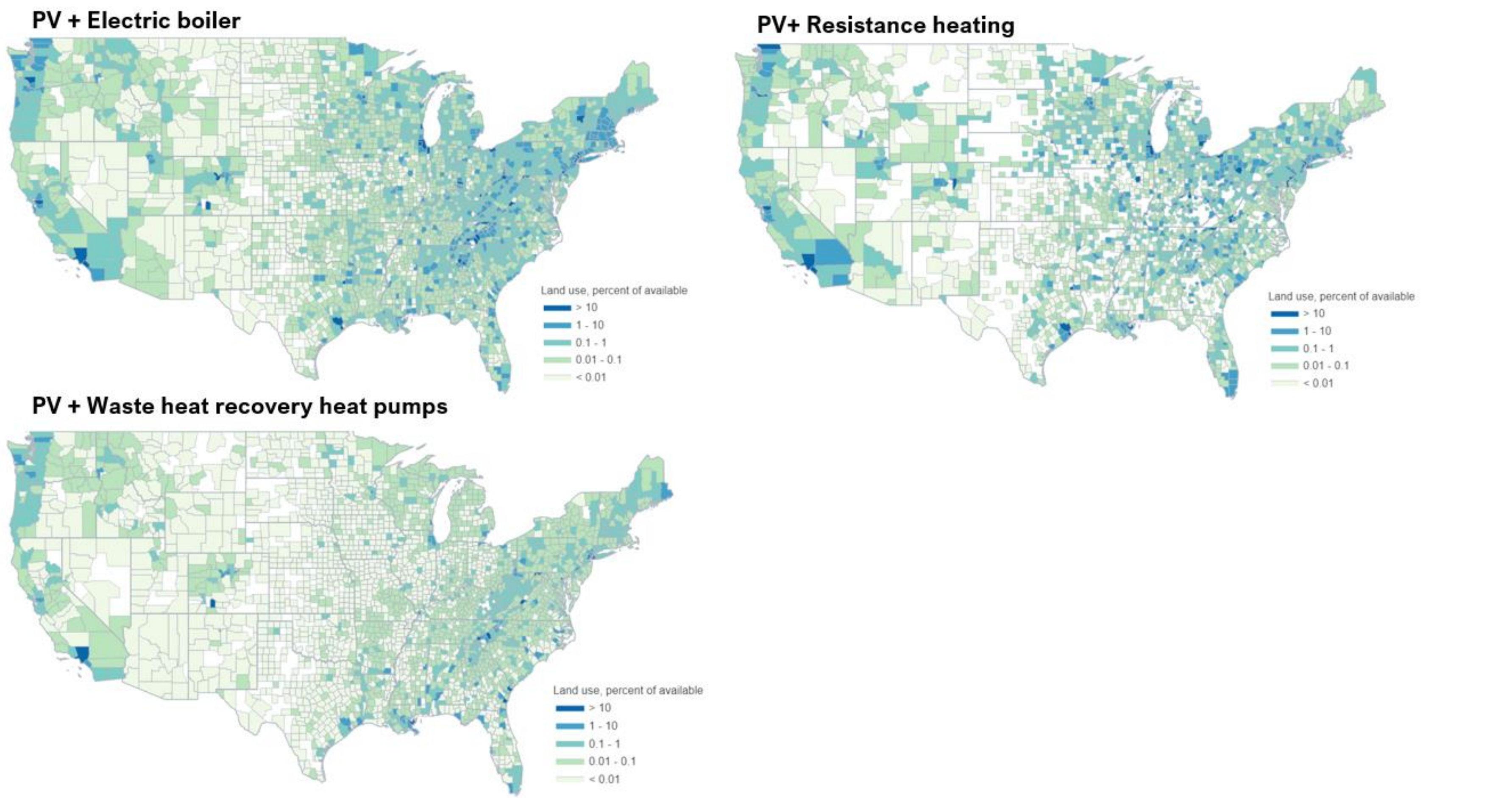


Figure 3-18. County-level maps showing land use as a percentage of the available land for PV-electrotechnologies, summer sizing

The total land use required ranges from 221 km^2 (0.2% of available land) for the FPC case to 5,463 km^2 (1.4% of available land) for the PTC with TES case, with summer sizing, and 521 km^2 (0.4% of available land) to 18,960 km^2 (2.9% of available land), with winter sizing. As a comparison, Connecticut, the third-smallest state by area, is 14,357 km^2.

3.3.6 Economic Process Parity Case Studies

Two conditions for process parity are explored: changing the SIPH system investment cost or changing the fuel price. Figure 3-19 and Figure 3-20 show the comparisons of current SIPH system costs (light green lines) and system costs needed to reach cost parity (dark green lines), and of current fuel prices (light orange lines) and fuel prices needed to reach cost parity (dark orange lines). Process parity is not achieved in any analysis location for current SIPH system costs and fuel prices. The Los Angeles county is most likely to achieve cost parity with ST technologies due to higher fuel prices compared to other counties. For the PV-electric boiler case, results are even less favorable for SIPH to reach cost parity.

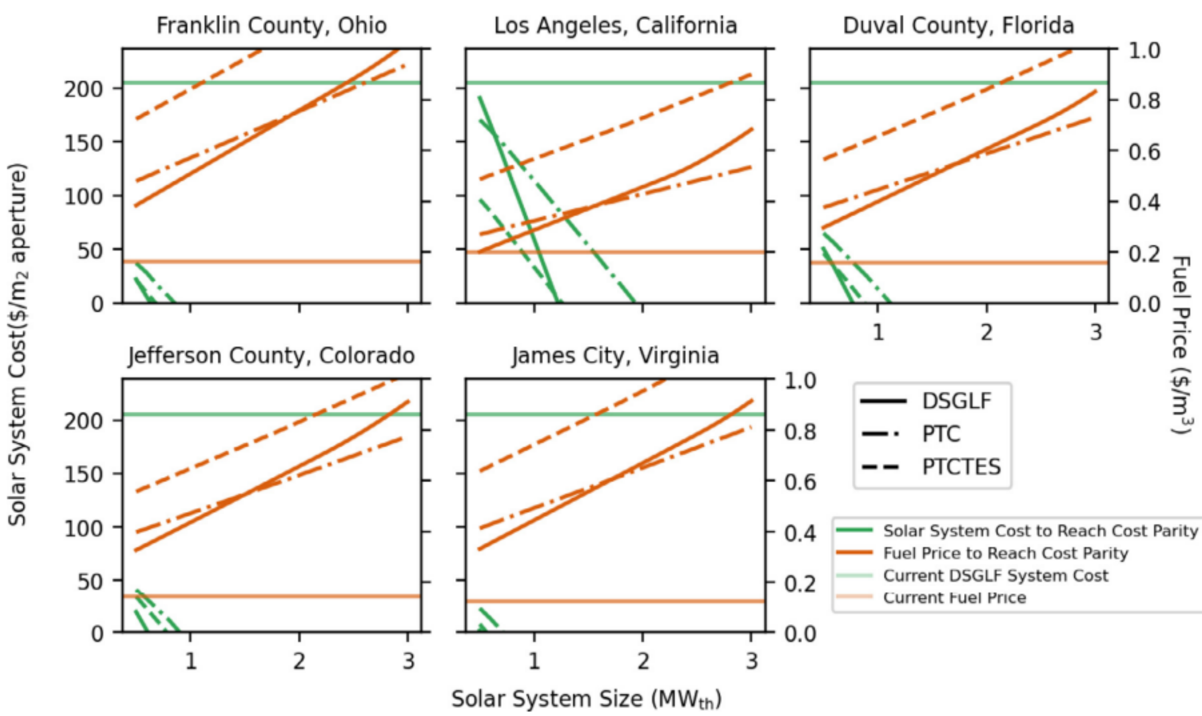


Figure 3-19. Parity investment and fuel price curves for ST technologies in each location as a function of solar system size at the heat exchanger (MWth)

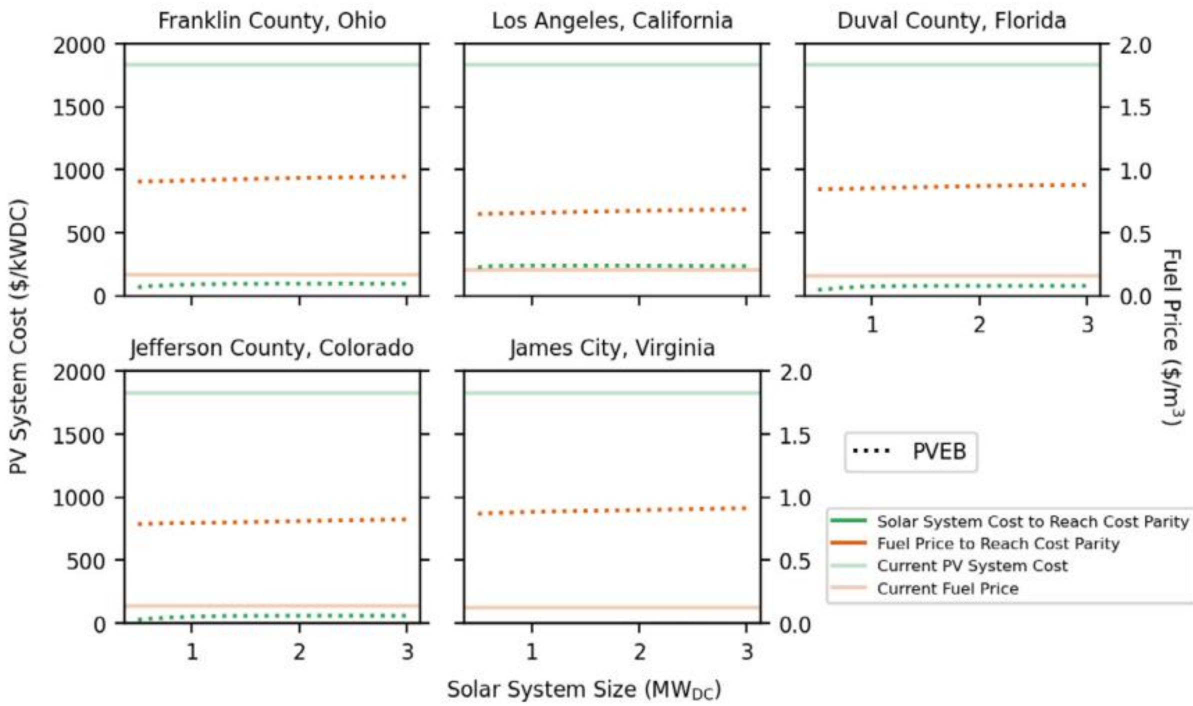


Figure 3-20. Parity investment and fuel price curves for PV-electric boiler (PVEB) in each location as a function of solar system size at the heat exchanger (MWth)

3.4 Conclusions

There are many opportunities for SIPH to reduce combustion fuel use and associated emissions in manufacturing industries and in all counties across the US. However, the magnitude of SIPH potential is limited by the ability for SIPH technologies to continuously meet IPH demand. The presence of TES systems significantly increases SIPH viability, but more research is necessary to find optimal applications for SIPH adoption. Future research could consider higher resolution analyses matching solar technologies to IPH demand at the facility-level, factoring in more detailed data on land area, heat transfer, and operating hours. Furthermore, along with capturing facility-level characteristics, additional research is needed on integrating SIPH technologies both with existing industrial operations and infrastructure, especially in the PV-electric technology cases, and in combination with load reduction (i.e., energy efficiency) measures. Additionally, evaluation of SIPH technologies could be expanded to capture life-cycle emissions.

4. Characterization of Industrial Boilers and Assessment of the Life-cycle Energy and Emissions of Boiler Electrification

This chapter presents an analysis of the electrification potential of industrial boilers in the US. First, an up-to-date inventory of industrial boilers in the U.S. is developed and further characterized by location, industry, capacity, and fuel type. The methods for developing this industrial boiler dataset involve integrating unit-level data from multiple national emissions databases. Second, the potential for boiler electrification, the net change in primary energy use, and life cycle GHG emissions impacts are calculated for multiple electric grid scenarios. The methods for evaluating the electrification potential and energy and emissions impacts build on previous modeling approaches described in Chapter 3, which consider technology energy efficiency and county-level process heat demand, and introduce ways to account for life cycle emissions of electrification technologies. Main findings from this research highlight the significance of power sector decarbonization in parallel with industrial sector electrification and suggestions of future research, which include comparative analyses of economic feasibility with other low carbon technologies.

This chapter is adapted from the following peer-reviewed article [138]: Schoeneberger, C., Zhang, J., McMillan, C. A., Dunn, J.B., Masanet, E. “Electrification Potential of U.S. Industrial Boilers and Assessment of the GHG Emissions Impact.” *Advances in Applied Energy*. 2022. 5, 100089.

4.1 Introduction

Transitioning energy systems from fossil fuels to decarbonized alternatives is more urgent than ever given the ongoing rise in global greenhouse gas (GHG) emissions and their escalating effects on the climate. With future increases in GHG emissions expected to cause additional warming of the planet [139], the immediate deployment of commercially available clean energy technologies is vital [140]. The electrification of industrial process heating is one such solution to decarbonizing a sector heavily reliant on fossil fuels. While industry has so far remained a difficult sector to decarbonize due to its wide array of products and processes and long-lived, capital-intensive process equipment stocks [4], industrial boilers represent a cross-cutting technology with significant potential for electrification.

With the second highest industrial energy consumption globally as of 2019, the U.S. is an important target for industrial decarbonization [141]. In the US, manufacturing industries are responsible for 21% of all energy-related GHG emissions, and process heating accounts for 31% of GHG emissions within manufacturing, as of 2018 [142], [143]. Although industrial heating applications can vary largely across manufacturing industries, in most cases they rely on fuel combustion for both direct-fired process heating and steam production [144]. Conventional boilers are used for steam production in almost all industries and consume roughly one third of the fuel used for process heating in manufacturing [145]. A large share of boiler fuel use is from natural gas (34%) and coal (11%), but a majority (54%) comes from other fuels, including biomass and byproduct fuels, such as black liquor, still gas, and waste gas [145]–[149]. Switching from fuel-based boilers to electric boilers may provide a straightforward and substantial opportunity for emissions reductions in many industrial plants.

The electrification potential (the amount of electricity required by electric boilers to meet steam demand) of U.S. industrial boilers and the emissions impact of boiler electrification depend largely on the current stock of conventional boilers and their fuel sources. However, the most recent set of published data on U.S. industrial boilers with key characteristics of industrial subsectors, installed capacity, and fuel types is from 2005 [150], whereas both the structure and energy use characteristics of the U.S. manufacturing sector have since changed substantially. In addition, this previous characterization of boilers is limited in scope and coverage, reporting boiler capacity ranges and fuel types separately for only five subsectors – food, paper, chemicals, refining, and metals – and relying on top-down estimations rather than bottom-up accounting of individual boiler units. It also lacks data on the geographic distribution of conventional industrial boilers, which is essential for evaluating the electric grid emissions associated with electric boiler operations as well as locally available renewable electricity.

While an updated inventory of industrial boilers with technical and geographic detail is needed to provide the basis for current boiler technologies and steam demand, additional assessments of electrified heating technologies and conventional boiler fuel use are also needed to quantify the country-wide energy and emissions effects of electrification. Previous studies have documented the benefits of electrification in industry and identified boilers as a top cross-cutting opportunity [10], [151]–[153]. Electric boilers have high thermal efficiency (~99%), fast ramp-up times, and low downtime [151] and require no onsite pollution abatement, combustion accessories, such as tanks, fuel links, and exhaust flues, or expensive combustion inspection [154]. They can also offer other non-energy benefits, such as lower capital, maintenance, and administrative costs and physical footprints, but the high cost of electricity relative to natural gas and other fuels has affected their economic feasibility [151]. Electric boilers could significantly increase the electricity load at industrial plants [151] [10], but they can also be operated flexibly to utilize low-cost power supply from renewables [152] and support increased renewable generation [153]. Heat pumps are another important technology for electrified hot water and steam, but they require waste heat from other processes and, thus, are out of scope since this study focuses on drop-in stand-alone boilers. While heat recovery is often already integrated in U.S. facilities for preheating makeup water or in economizers, waste heat for export, such as district heating, could be considered in other countries. This analysis on electric boilers can be useful for future comparisons to heat pumps and other electrotechnologies.

Recent studies assessing the energy and emissions implications of electrifying industrial heat in Germany [155] and in Europe [156] show that emissions savings from electrification are possible only under scenarios where electric boilers are operated in a hybrid setup with renewable electricity or from an electric grid with low carbon intensity. Schüwer et al. calculate an increase of 0.2-0.6 $MMmtCO_2e$/year from electrifying industrial boilers in Germany in 2020 and a decrease of 5.9-15.9 $MMmtCO_2e$/year in 2050, assuming an 80-95% reduction in electricity carbon intensity in 2050 [155]. Several reports centered on U.S. electrification of industry evaluate electric boilers, but either assume limited adoption relative to other electrotechnologies [157] or simplify their accounting of fuel use in a high-level, national analysis [158]. Hasanbeigi et al. estimate savings of 140 TBtu in final energy of industrial boilers and an initial increase in CO_2 emissions, followed by a decrease of 1,000 $MMmtCO_2$/year by 2050, assuming future grid decarbonization [158]. However, these findings based on aggregated national manufacturing energy data [159] exclude fuels categorized as "other," such as biomass and byproducts used as fuel, in its boiler energy use estimations as well as the additional power plant fuel energy inputs required for electrification.

Since the composition of primary energy sources in the current electric grid differs widely by region within the US, a spatial analysis pairing the locations of industrial boilers and regional makeups of the electric grid is needed to provide a more accurate and location-specific estimation of electrification potential. To date, there has been no detailed study on the county-level electrification potential and emissions impact of industrial boilers that also considers the current boiler capacity and fuel type distribution.

This study makes two novel contributions toward understanding the energy and emissions effects of widespread industrial boiler electrification in the United States. First, we develop a comprehensive and up-to-date dataset that characterizes the total population of conventional industrial boilers by county, industrial subsector, installed capacity, and fuel type. Our research integrates multiple national facility-level emissions databases and accounts for remaining boilers based on county-level fuel estimates. Second, we calculate the county-level electrification potential and GHG emissions impact for industrial boilers under multiple electric grid scenarios, considering both the additional fuel use and emissions from electricity generation. This research addresses key knowledge gaps about the climate change mitigation potential of electric boilers and highlights the need for further analysis around assembling facility-level equipment, fuel use, and emissions data from publicly available yet non-standardized data sources.

4.2 Methods

This analysis extends previous work documented in Chapter 3 [113] to achieve two research outcomes: (1) developing a comprehensive and public dataset that characterizes the current stock of conventional industrial boilers in the U.S. and (2) calculating net changes in fuel use and GHG emissions from boiler electrification under different electric grid scenarios.

The methodology for creating our industrial boiler dataset requires integrating data on boiler units reported in the following national emissions databases: the U.S. Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP) [160], the Boiler Maximum Achievable Control Technology (MACT) Draft Emissions and Survey Results Database [161], and the National Emissions Inventory (NEI) [162]. To account for boilers not reported in the above databases, estimates of county-level fuel use from the National Renewable Energy Laboratory (NREL) manufacturing thermal energy use dataset [145] are used for deriving the populations and characteristics of remaining boilers. Manufacturing thermal energy use data are then applied to calculations of electrification potential, defined in Section 4.2.3, by U.S. county and industrial subsector. Net changes in GHG emissions are calculated from emissions factors of fuels avoided and fuels required for electricity, as well as the GHG emissions associated with current and future electric grids.

This section further describes the primary data sources, the process of data integration, and the methods and assumptions used to quantify the electrification potential and net changes in GHG emissions.

4.2.1 Data Integration and Development of Industrial Boiler Dataset

Descriptions of the GHGRP, MACT, and NEI databases and the categories of data included in this study are described in Table 4-1.

Table 4-1. Descriptions of the GHGRP, MACT, and NEI databases [163]–[165]

	GHGRP	**MACT**	**NEI**
Main data reported	Unit-level GHG emissions (CO_2, CH_4, N_2O)	Unit-level air pollutants (CO, NOx, PM, SO_2)	Unit-level emissions and air pollutants (VOCs, PM, metals, GHGs, etc.)
Reporting requirements	Mandatory for facilities that generate at least 25,000 mtCO2e/year	Survey	Submitted data provided by State, Local, and Tribal air agencies and supplemented data from U.S. EPA
Reporting frequency	Annual, since 2010	Once, in 2012	Every three years, since 2008
Database category relevant to industrial boilers	Emissions by Unit and Fuel Type: General Stationary Fuel Combustion (Subpart C)	Inventory: Major Source Boilers and Process Heaters	NEI point sources
Data characteristics relevant to this study	Facility ID, NAICS code (6-digit), reporting year, unit name, unit type, unit input capacity (MMBtu/hr), unit fuel type	Facility ID, NAICS code (3-digit), unit ID, unit type, unit design capacity (MMBtu/hr), unit fuel category	Facility ID, NAICS code (6-digit), reporting period, unit ID, unit type, unit design capacity, unit description (for fuel type)
Number of line items in relevant database category	253,683	8,320	8,202,877
Number of boilers from source in final dataset	794	4,412	13,988

The NREL manufacturing thermal energy use dataset provides county- and industry-level fuel use estimates for conventional boilers, combined heat and power (CHP), and process heating for the year 2014, and is derived from the emissions reporting from the 2014 GHGRP and U.S. Energy Information Administration 2014 Manufacturing Energy Consumption Survey (MECS) data. These fuel use data are used to estimate the populations of conventional boilers not reported in the databases summarized in Table 4-1.

While the GHGRP, MACT, and NEI databases all supply unit-level characteristics of facility location, subsector, installed capacity, and fuel type, each is organized in a different structure, and integrating the relevant characteristics of boiler units involves a series of data filtering and cross-checking operations. The databases are independent but not necessarily mutually exclusive, meaning that individual boiler units could be present in more than one database and, thus, a process of cross-checking is required to identify and remove duplicate entries.

Figure 4-1 summarizes our process for the integration of emissions databases and manufacturing fuel data. The full process flow diagrams and additional details on assembling the inventory of reported boilers and final industrial boiler dataset are described further in Appendix B.

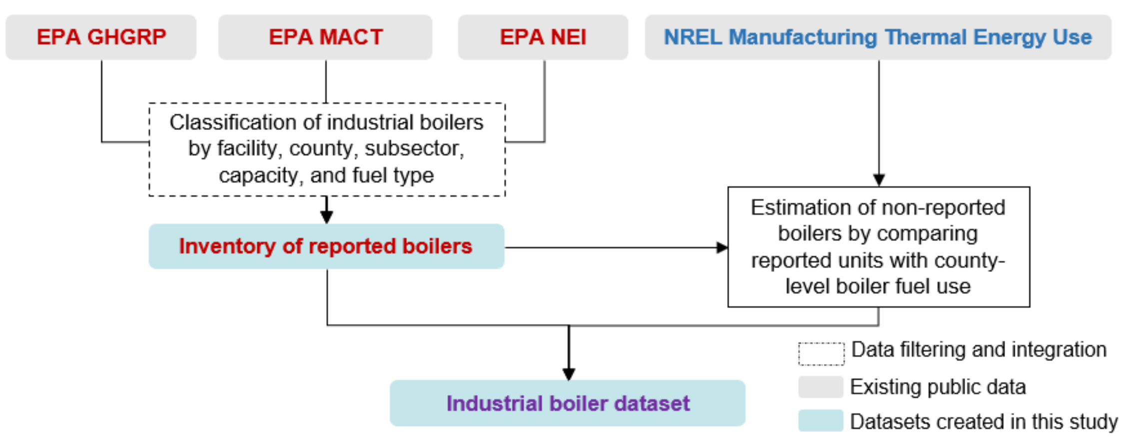


Figure 4-1. Flow diagram of data sources and integration for assembling the industrial conventional boiler dataset

With GHGRP data, boilers are selected based on "unit type," "unit name," and North American Industry Classification System (NAICS) codes 31-33, representing the U.S. manufacturing sector. MACT data are likewise filtered for manufacturing NAICS codes and for unit types of industrial boilers, and these are merged with GHGRP boilers by facility, county Federal Information Processing Standards (FIPS) codes, and boiler capacity, and duplicate units are removed. Similarly, NEI boiler data are filtered by NAICS code and unit type, but also through text search for boilers listed by other unit types, such as "other combustion" or "other process equipment," and are then merged with the existing inventory by facility, county FIPS codes, and boiler capacity, with duplicate units removed. CHP boilers are not included in our industrial boiler dataset because replacement or hybridization with electric boilers would significantly affect the electricity generation and economics of CHP operations; consideration of these important effects is beyond the scope of this study. Boilers identified in the EPA databases are checked against a database of industrial CHP facilities, as detailed in Form EIA-923 [166], and CHP boilers are removed.

After devising an inventory of reported units, the remaining (i.e., non-reported) count of boilers per county is estimated by comparing boiler fuel use in each county and subsector, as indicated by the NREL manufacturing thermal energy use dataset, to the maximum boiler fuel use possible from boilers in the inventory of reported units. The equation to calculate the maximum possible boiler fuel use of reported boilers in the inventory, F_{inv}, per county and subsector, is based on the total installed capacity of reported boilers within the county and NAICS subsector, $C_{c,N}$, and reported operating hours per subsector, t_N, shown in Equation 4-1. Operating hours data are taken from the GHGRP and averaged for each subsector.

$$F_{inv} = C_{c,N} * t_N \qquad (4\text{-}1)$$

Two cases are encountered when estimating the counts of non-reported boilers per county and NAICS code: (1) there is boiler fuel use as indicated by the NREL thermal energy use dataset but no reported boilers in our inventory from the Table 4-1 databases, and (2) there is greater fuel use indicated in the NREL dataset than what reported boilers are estimated to consume according to Eq. 4-1. In case (1), the count of non-reported boilers, *b*, is estimated based on the boiler fuel use, $F_{c,N}$, operating hours, and median installed boiler capacity per NAICS subsector, C_N, shown in Eq. 4-2. The median installed boiler capacity is used in Eq. 4-2 to reduce the influence of outliers in data where there are no reported boiler data as in case (1), whereas the average installed boiler capacity is used when reported boiler data are available for the county and subsector. In case (2), the count of non-reported boilers is estimated based on the difference between boiler fuel use and the maximum boiler fuel use of reported boilers in the inventory, operating hours, and average installed boiler capacity per county and NAICS subsector, $C_{c,N}$, shown in Eq. 4-3.

$$\begin{cases} \textit{Case 1: } F_{inv}(=0) < F_{c,N}\ ; \quad b = \dfrac{F_{c,N}}{t_N * C_N} & (4\text{-}2) \\ \textit{Case 2: } F_{inv} < F_{c,N}; \quad b = \dfrac{(F_{c,N} - F_{inv})}{t_N * C_{c,N}} & (4\text{-}3) \end{cases}$$

To account for the boiler capacity values of non-reported boilers, we assume a boiler capacity distribution for the non-reported boilers that reflects the capacity distribution of reported boilers with low boiler capacity ranges (<10 MMBtu/hr and 10-50 MMBtu/hr) per subsector. The distribution of low boiler capacity ranges is used here to account for smaller boilers often overlooked by national databases, which by design capture large units more frequently. Fuel types of the boilers are similarly determined based on the distribution of boiler fuel types per subsector.

For non-reported boilers within a county and subsector, the fuel type is estimated according to the percentage of fuel type weighted by boiler energy consumption.

4.2.2 Calculations of Electrification Potential, Primary Energy, and GHG Emissions

Electric boilers are a commercialized technology that pass an electric current through the water between electrodes (electrode boilers) or through immersed heating elements (electric resistance boilers) to produce steam and hot water [167]. While electrode boilers tend to have higher maximum capacities, up to 335 MMBtu/hr, than electric resistance boilers, the efficiencies of both electric boilers are nearly 100% [168]. Electric boilers are also generally more compact than fossil fuel boilers, allowing parallel electric boilers to be viable options for replacing single larger fossil fuel boilers. In our calculations of electrification potential, we therefore assume that electric boilers can fully replace the steam demand from conventional fossil fuel boilers. We also note that the small amount of electricity inputs for boiler controls for both fuel and electric boilers is excluded in our calculation of electrification potential, as the percentage is negligible compared to fuel or electricity directly used for thermal energy. We further assume that sufficient grid capacity exists to enable full boiler electrification in our scenarios, but future studies should consider marginal demand implications on local grids to further assess technical feasibility.

The methodology for calculating the technical potential of boiler electrification is based on previous work that analyzed opportunities for solar industrial process heating, including the use of photovoltaic electricity for electric boilers [113]. From the same NREL manufacturing thermal energy use data, the fuel use for conventional boilers is characterized by county, NAICS subsector, and fuel type and, along with considerations of efficiency losses from fuel combustion, is used to determine the steam demand met by existing boilers.

The electrification potential is defined as the amount of electrical energy required by electric boilers to meet steam demand, and is calculated based on the following equation:

$$E = F_{c,N,f} * \eta_{b,f} * \frac{1}{\eta_e} \qquad (4\text{-}4)$$

Where E is electrification potential (MWh), $F_{c,N,f}$ boiler fuel demand per county, NAICS subsector, and fuel type, $\eta_{b,f}$ conventional boiler efficiency by fuel type, and η_e electric boiler efficiency. Conventional boiler efficiencies can vary from boiler to boiler depending on boiler configurations and operating practices, but due to lack of data on individual operations, we assume average nationwide boiler efficiencies dependent on its fuel type (Table 4-2). Electric boiler efficiency is assumed to be 99% [167].

Table 4-2. Conventional boiler efficiencies by fuel type [169]–[171]

Boiler fuel type	**Efficiency (%)**
Natural gas	75
Coal	81
LPG & NGL	82
Diesel	83
Residual fuel oil	83
Coke & breeze	70
Other	70

With the county-level electrification potential, we then calculate net changes in GHG emissions by considering the fuel avoided from conventional boilers as well as the makeup of regional electric grids to account for the source of electricity and their associated emissions. The amount of power plant input fuel required to meet electricity demand is calculated from heat rate values from the EPA's 2019 eGRID database [172] and the resource mix of fuels used in regional electric grids and accounts for grid losses (Figure 4-2). Resulting emissions are calculated based on full fuel cycle GHG emissions factors by fuel types, according to EPA combustion emissions factors for GHG inventories [173] and fuel cycle emissions factors from the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model [174]. Emissions from non-fossil sources are assumed to be zero, as the life cycle emissions factors for these electricity generation technologies are a tiny fraction of fossil fuel-based technologies [175].

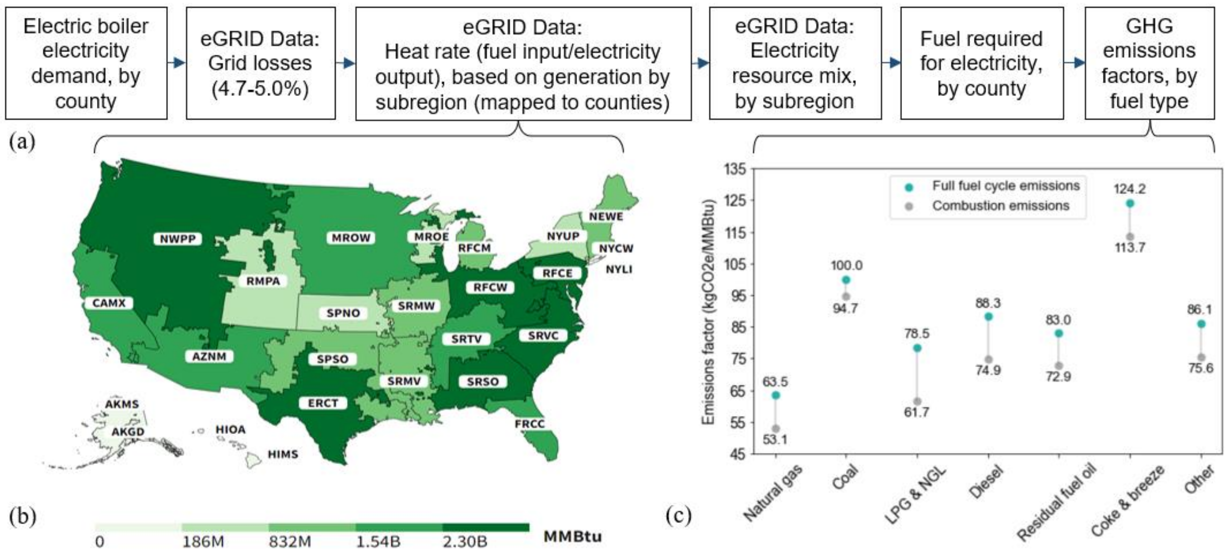


Figure 4-2. (a) Flow diagram for calculating annual net change in GHG emissions of boiler electrification with **(b)** eGRID electricity heat rate data [172] and **(c)** GHG emissions factors for the full fuel cycle including emissions from combustion and upstream processing

Net changes in GHG emissions are calculated for each county with the current electric grid and in two potential future electric grid scenarios. Further descriptions of the resource mixes of the electric grids are provided along with results in Section 3.3. In calculating net fuel use and GHG emissions changes, we note several assumptions about the electrification potential, fuel consumption for electricity, and emissions factors. First, the electricity required for electric boilers is based on boiler energy demand from 2014, which is assumed to be the same in the year of the electrification analysis for the current grid (2019). Second, the fuel consumption for electricity required by electric boilers is based on power plant heat rate and resource mix data within an eGRID subregion, as opposed to smaller regions of the power grid or larger interconnected regions.

Third, average emissions rates for each fuel type are used instead of marginal emissions rates. Although the calculations of electrification potential and GHG emissions impact is for industrial boilers in the US, our methods and data considerations can be extended to future technical potential analyses in other countries where the electrification of the industrial sector is important.

4.3 Results and Discussion

4.3.1 Characterization of Industrial Boilers

The inventory of reported boilers with complete information on location, subsector, capacity, and fuel types amounts to 18,954 units. As discussed previously, there are also many non-reported units, especially low-capacity boilers, that are not surveyed or monitored in the Table 4-1 emissions databases. Combining the estimated count of non-reported boilers from our method using county-level fuel use and the reported boilers, the total number of conventional industrial boilers is estimated to be 38,537. Their distributions among manufacturing subsectors and by boiler capacity ranges are shown in Figure 4-3. The total number of boilers is compared to the estimated count of industrial boilers from 2005 [150] and to the number of U.S. manufacturing establishments overtime [176] to assess the validity of our results. These and additional comparisons between our assessment and [150] are described further in Appendix B.

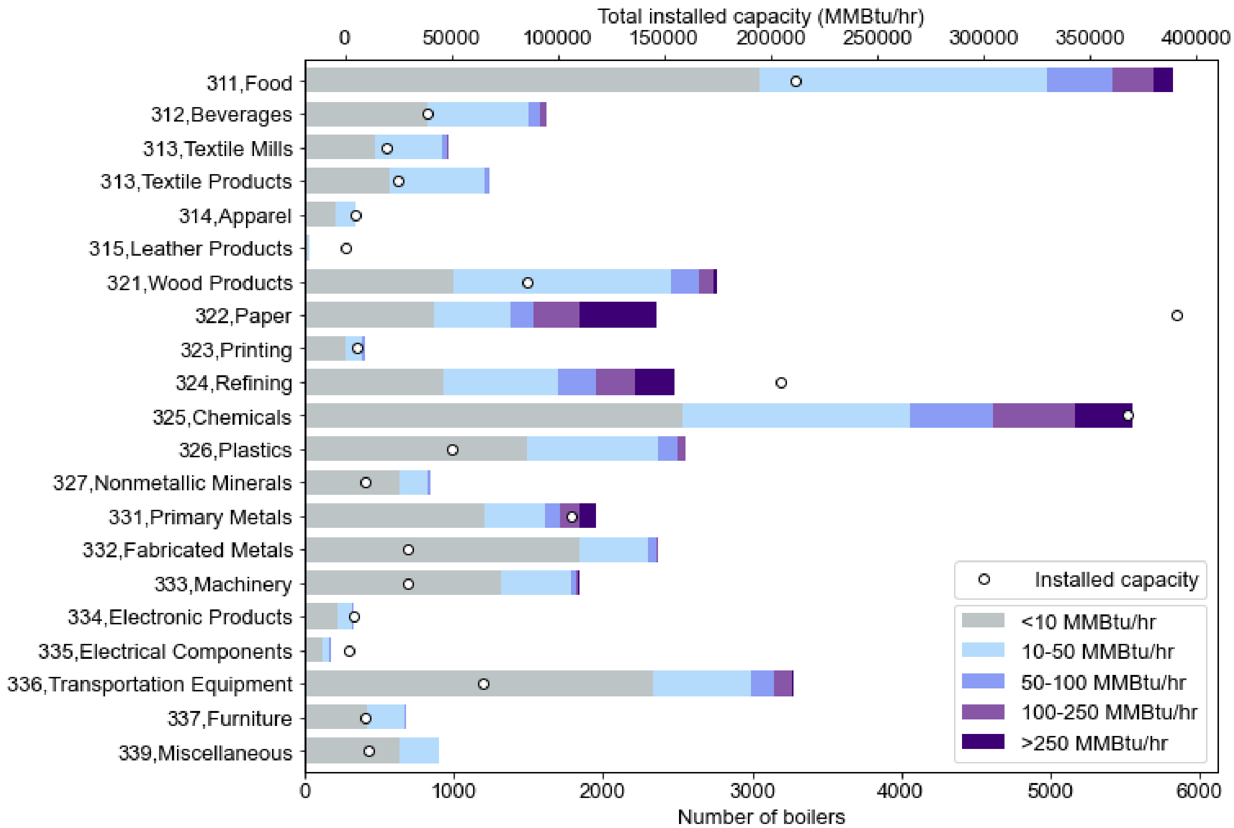
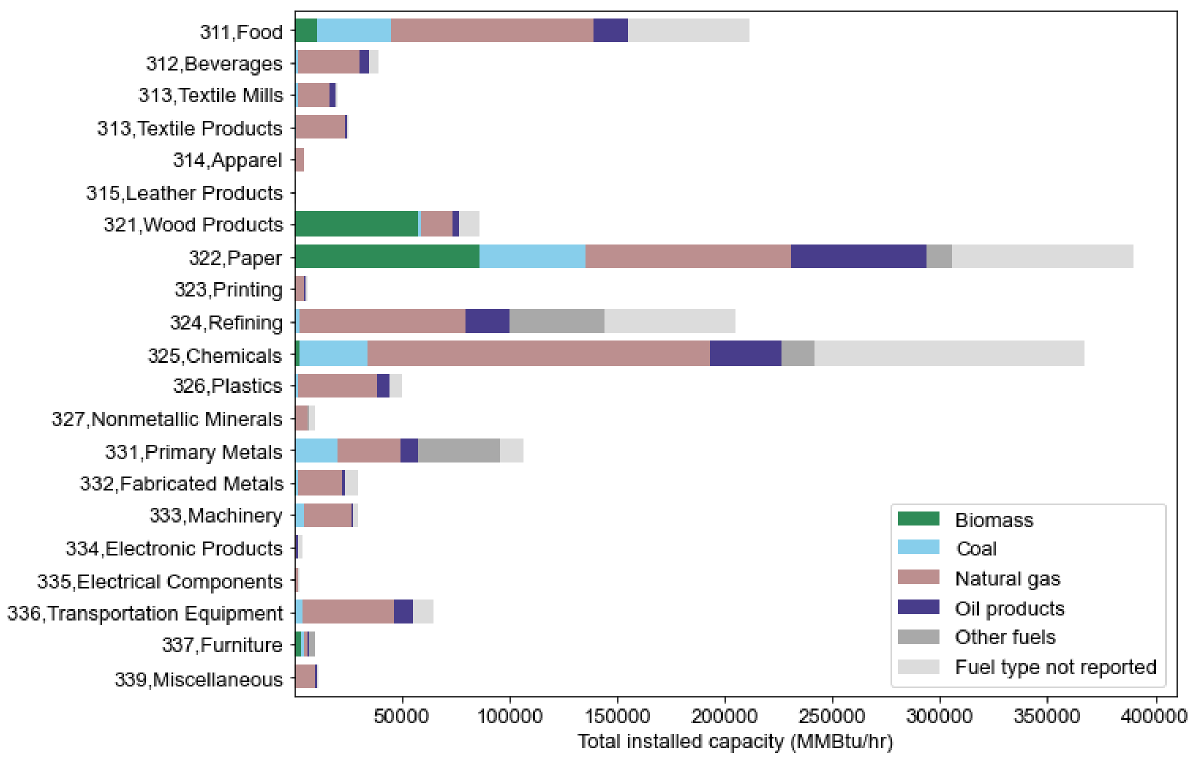


Figure 4-3. Estimated distributions of industrial boilers by NAICS manufacturing subsectors and capacity range

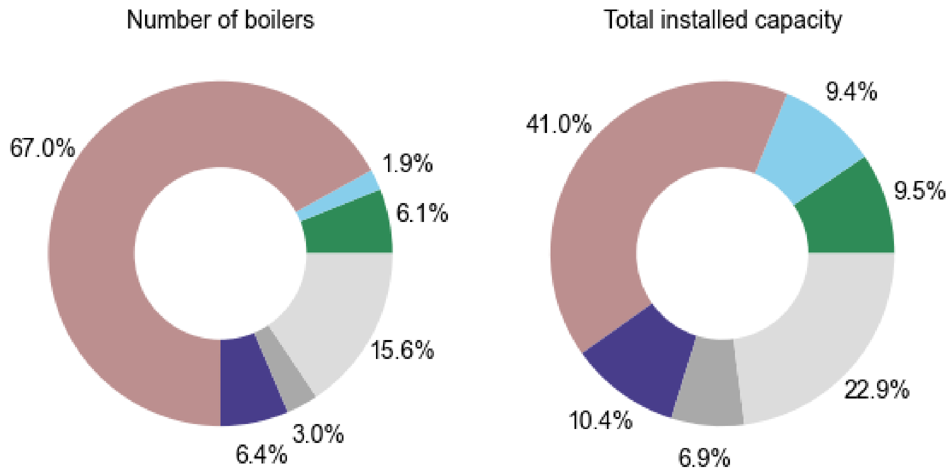
The food and chemicals subsectors have the highest estimated number of boilers with similar capacity distributions, where the majority of boilers fall into the low-capacity ranges (<10 MMBtu/hr and 10-50 MMBtu/hr). The large number of boilers in the food subsector reflects both the quantity of food manufacturing establishments – second most among all the manufacturing subsectors – and a high steam demand for a wide variety of process heating applications [177]. Its large portion of low-capacity boilers can be attributed to a high percentage of small-sized food manufacturing facilities – 80% of food manufacturing establishments have employment totals of less than 50 people [176]. According to U.S. DOE Industrial Assessment Centers (IAC) which provide technical assessments of manufacturing plants, energy usage is generally higher in plants with a larger employment size [178]. Similarly in the chemicals subsector, while commodity chemicals are produced in bulk in large-scale facilities, there are also numerous smaller and more differentiated facilities for specialty, agricultural, and consumer product chemicals that require various levels of steam demand, and thus, a high percentage of low-capacity boilers [179], [180]. The paper subsector has a considerably large number of boilers that are high-capacity (>250 MMBtu/hr) as pulp and paper mills tend to be large facilities, where nearly 50% of paper manufacturing establishments have employment totals of 50 or more people [176], with many steam-intensive processes [181].

The paper, chemicals, food, and refining subsectors have the largest overall installed capacity of industrial boilers. These four subsectors also have the highest steam demand for process heating in U.S. manufacturing [177], as well as a large number of high-capacity boilers. However, operational parameters, such as boiler capacity utilization, which can differ by subsector and individual facilities, determine fuel consumption totals that ultimately affect potential for electrification and emissions reductions. Boiler fuel types likewise affect which boilers can be practically substituted with electric boilers as well as the net changes in emissions.

The fuels used in industrial boilers consist of natural gas, biomass, coal, oil products (fuel oil, diesel, LPG), and other fuels (still gas, waste gas, solid byproducts). The share of these fuels varies significantly among manufacturing subsectors (Figure 4-4(a)) and depends on both regional fuel costs and the availability and utilization of byproducts from certain manufacturing processes. For example, the petroleum refining subsector uses still gas and petroleum coke as byproduct fuels for over 60% of its onsite fuel consumption [147]. Similarly, the wood and paper subsectors use black liquor, a biomass byproduct of the Kraft process for converting wood to pulp and paper [182], for 40% of its onsite fuel consumption [146]. In the iron and steel industry, blast furnace and coke oven gases make up 27% of fuel consumption [149], although fuel use for boilers and steam demand are comparatively small. The use of byproduct fuels complicates the feasibility of boiler electrification in certain subsectors because facilities would have the added cost of purchased electricity as well as selling or disposal costs for the stranded byproducts. In other sectors which use wastes as fuel, such as municipal solid waste in waste-to-energy applications, the electrification of boilers would similarly eliminate the co-benefits with waste reuse, and studies that investigate electric boilers in these sectors should account for these co-benefits.



(a)

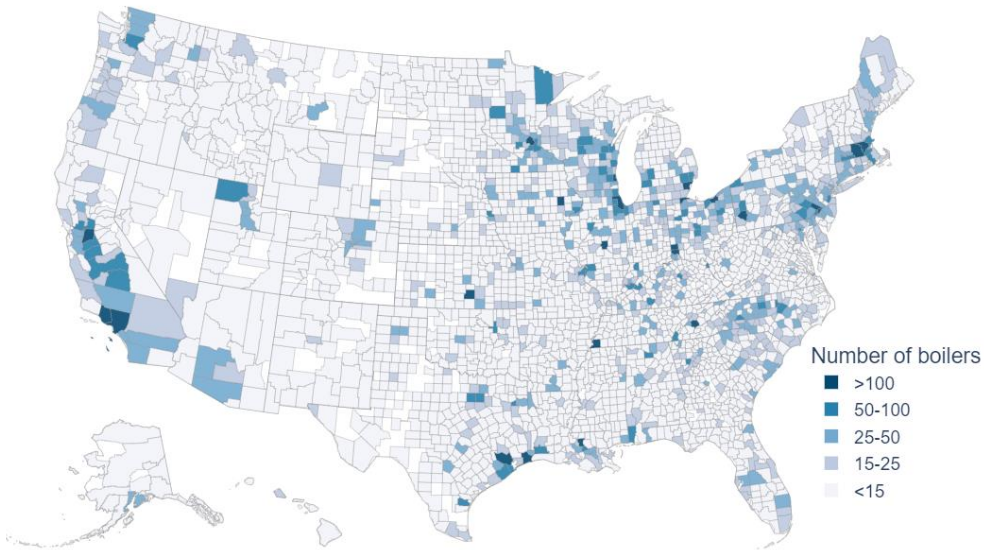


(b)

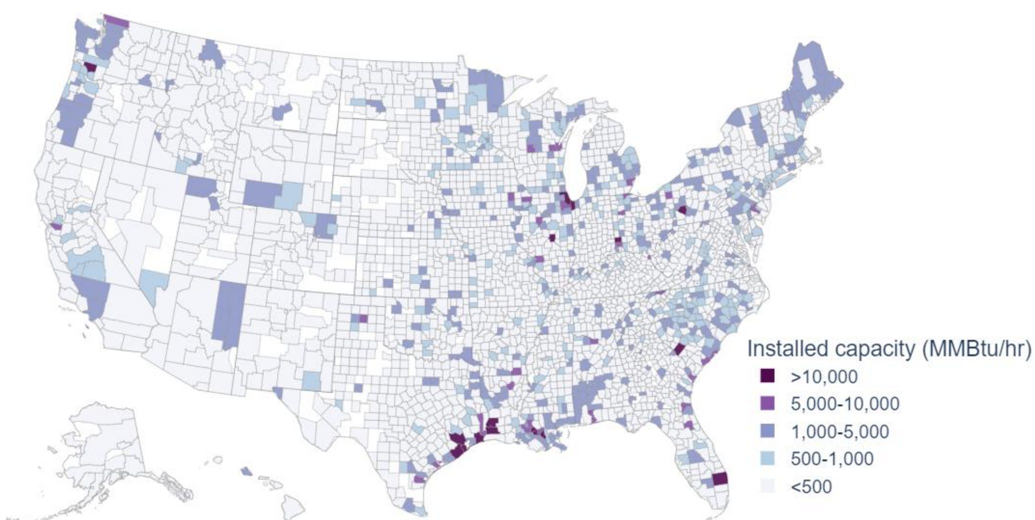
Figure 4-4. (a) Estimated distributions of total boiler installed capacity by NAICS manufacturing subsectors and fuel type. “Other fuels” include still gas, waste gas, black liquor, among others listed in SI Table S1. Boilers from the EPA databases with a known installed capacity and subsector but without fuel type information are included above with “fuel type not reported.” **(b)** Percentages of number of boilers and total installed capacity by fuel type

As shown in Figure 4-4(b), natural gas is the predominant fuel among industrial boilers in both the total quantity of boilers and installed capacity. While the number of natural gas boilers is high, many of them are low-capacity boilers with an average installed capacity of 30 MMBtu/hr. Conversely, the number of GHG-intensive coal boilers is relatively low, but the majority of coal boilers have capacities over 100 MMBtu/hr, and these high-capacity coal boilers are mostly used in the following subsectors: paper, food (wet corn milling, sugar, and oilseed industries), chemicals, and metals (iron and steel industry). Like coal boilers, fuel oil and diesel boilers are still used in small numbers in the paper and chemicals subsectors and could be a target for electrification due to their high emissions intensity and small number of relatively high installed capacities.

The location of industrial boilers is significant for evaluating the GHG emissions implications of boiler electrification, where renewable resource availability and emissions impacts vary greatly by region. Figure 4-5 shows the estimated numbers of boiler units and total installed capacities per county.



(a)



(b)

Figure 4-5. U.S. county maps of **(a)** number of boilers and **(b)** total installed boiler capacity

Many conventional industrial boilers are concentrated in California, the Midwest, and the Northeast, but still are present in almost all counties across the United States. Counties in Texas, Louisiana, Indiana, Pennsylvania, and Washington have the highest total installed capacities. In counties with a large total installed capacity, there is typically a large portion of high-capacity boilers. For example, in Harris County, Texas, where there is a large presence of chemicals and refining facilities, the average installed capacity of industrial boilers is 150 MMBtu/hr. Similarly in Cowlitz County, Washington, where 28 of the 44 industrial boilers are in the paper subsector, the average installed boiler capacity is 360 MMBtu/hr. With large industrial boilers, replacement with electric boilers may require multiple electric boilers to meet capacity needs, leading to more extensive capital investments, despite the generally lower capital cost of electric boilers [183].

4.3.2 Electrification Potential

While the characterization of industrial boilers by installed capacity, as shown in the previous section, illustrates the current stock of equipment, the electrification potential represents the energy associated with electrifying boilers. Specifically, the electrification potential depends on the boiler fuel consumption for steam demand in each subsector and county. Boiler fuel consumption, which differs from installed capacity due to differences in hours of operation and capacity utilization, is taken from the NREL manufacturing thermal energy use dataset that was used in our characterization of non-reported conventional boilers. Moreover, it should be noted that the fuel type categories in the NREL dataset and presented in this section vary slightly from those shown in Section 4.3.1 due to differences in fuel type classification between the Table 4-1 databases and MECS data (see Appendix B for more detail). Figure 4-6 shows both estimated boiler fuel consumption by fuel type and the calculated electrification potential, totaled for each manufacturing subsector.

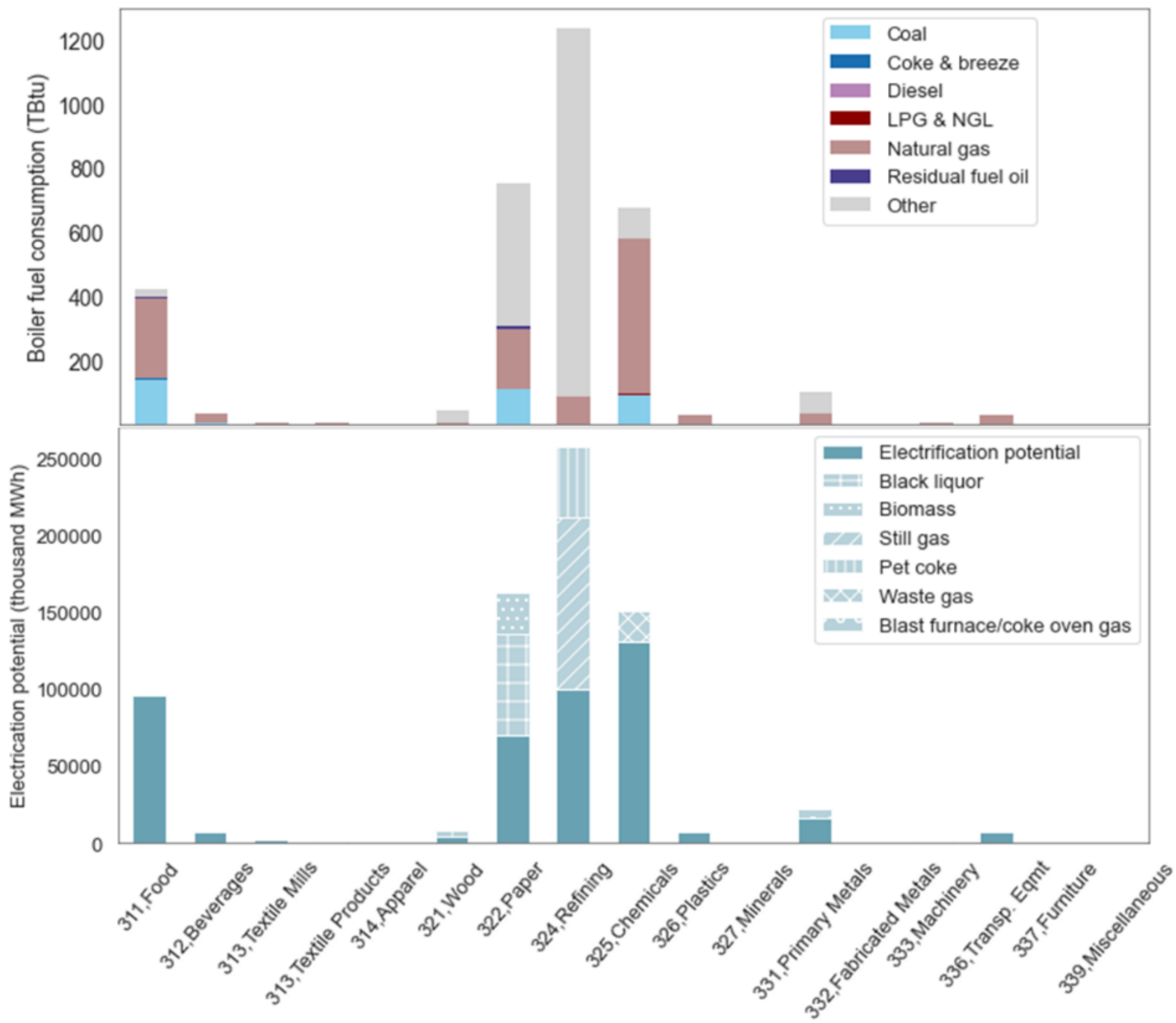


Figure 4-6. Conventional boiler fuel consumption in 2014 by fuel type and NAICS manufacturing subsectors **[145]** (top) and electrification potential with the exclusion of specified byproduct fuels by NAICS manufacturing subsectors (bottom)

The petroleum refining, paper, chemicals, and food subsectors have the highest industrial boiler fuel use, but in refining, paper, and chemicals, a large percentage of boiler fuel consumption comes from fuels other than natural gas, coal, or oil products. In these subsectors and, to a smaller extent, in metals, food, and transportation equipment manufacturing, the use of byproduct fuels in conventional boilers is prevalent. Due to the complexity and added costs of replacing byproduct fuel use with electrification, the electrification potential is calculated for two cases: (1) all boiler fuel consumption is replaced with electrification, and (2) byproduct fuels are excluded from replacement, as marked by the light textured bars in Figure 4-6. If all conventional boiler fuel use is replaced with electrification, the total electrification potential is 729,650 thousand MWh (2,490 TBtu), and if by byproduct fuels are excluded, the total electrification potential is 447,580 thousand MWh (1,527 TBtu). For reference, the total electricity demand in U.S. manufacturing in 2018 was 894,476 thousand MWh (3,052 TBtu) [184]. The electrification potential in both cases indicates a significant change to the energy mix of industrial manufacturing, nearly doubling the amount of electricity use in manufacturing and increasing the amount of boiler electricity by two orders of magnitude [185].

4.3.3 Net Change in Fuel Use and GHG Emissions

To understand the net changes in overall fuel use associated with tapping the estimated electrification potential, we consider the resource mixes and power plant heat rates (fuel inputs per electric power output) of regional electric power grids in the US, according to eGRID 2019 data [186]. The fuels inputs necessary for the electricity required by electric boilers are compared to onsite fuel savings, or avoided fuels, from conventional boilers (Figure 4-7). The fuel energy required to electrify boilers (4,275 TBtu) exceeds the fuel savings from replacing conventional boilers (3,337 TBtu) and leads to an increase in total national coal and natural gas consumption. This increase can be attributed to the low thermal efficiencies of coal and natural gas power plants and a sizable percentage of the electricity resource mix still met by these fossil fuels in counties with industrial boilers. Similarly, the net change in fuel use when byproduct fuels are excluded from electrification results in an additional fuel requirement of 619 TBtu and increased amounts of national coal and natural gas use. When byproduct fuels are excluded, there is an increased share of additional coal due to the location of facilities that use a large amount of byproduct fuels, especially in the Midwest, where there is a high percentage of coal in the electric grid mix.

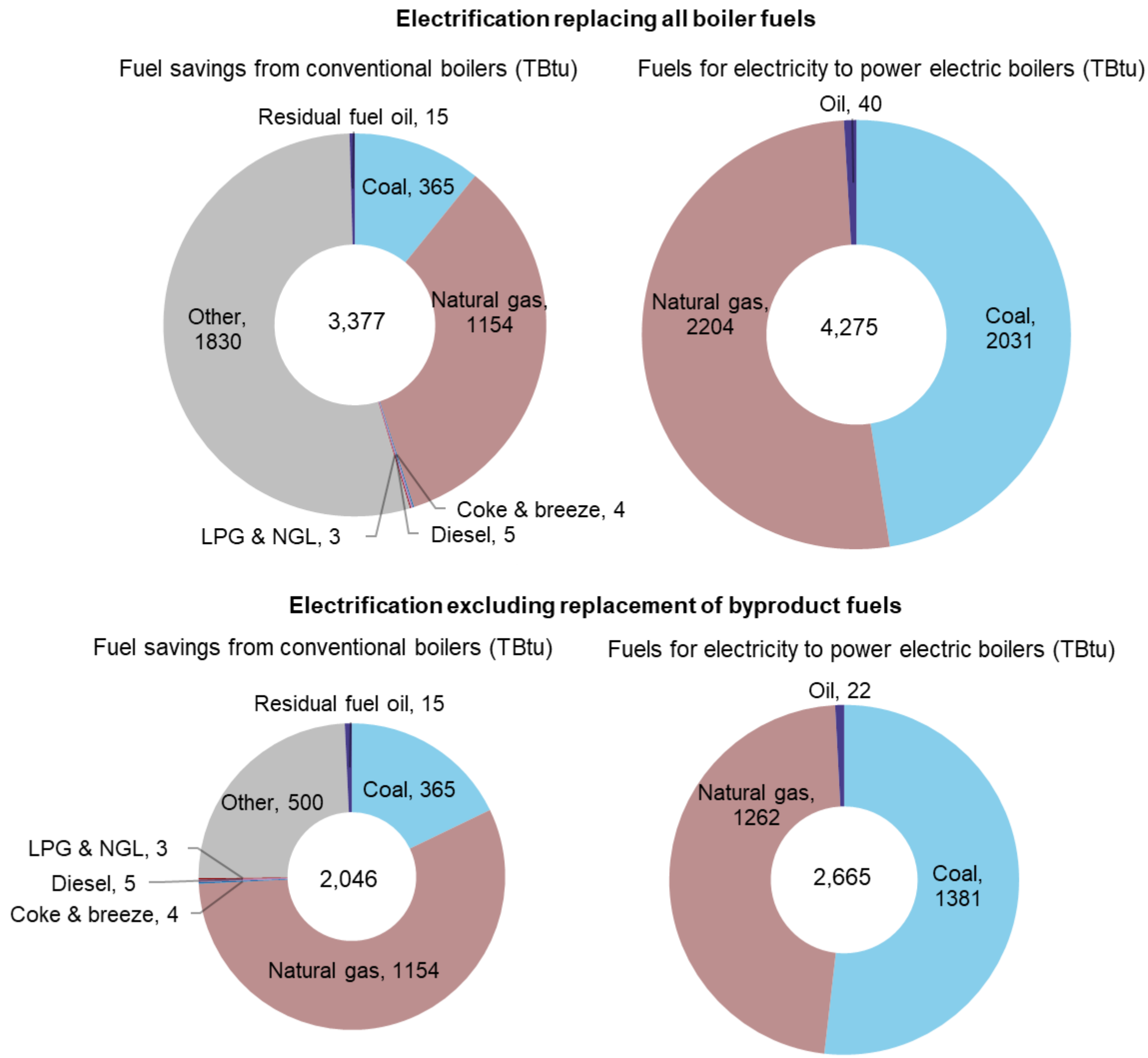
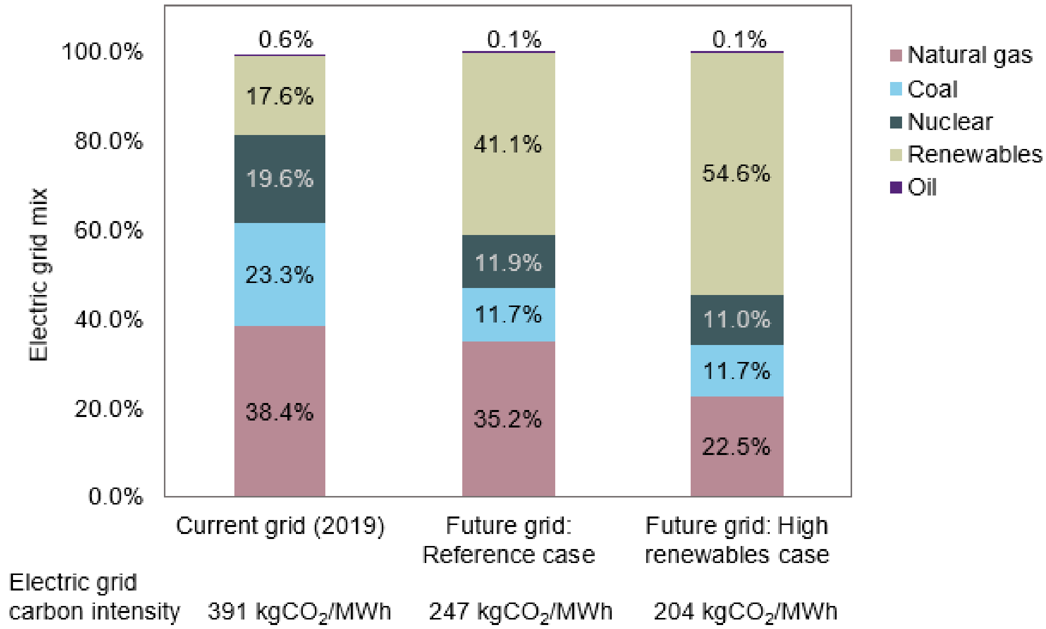


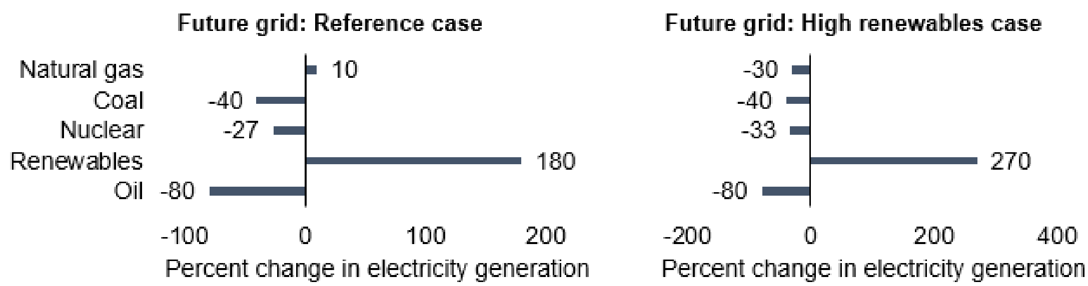
Figure 4-7. Estimated changes in fuel use from boiler electrification if all boiler fuels are avoided (top) and if byproduct fuels are excluded from electrification (bottom). Based on eGRID 2019 electric power mix.

The estimated net changes in fuel use shown above are based on the current U.S. electric grid mix, where the most recent eGRID data from 2019 details a combined U.S. grid mix of 38.4% natural gas, 23.3% coal, 19.6% nuclear, 17.6% renewables and <1% oil [186]. In the future, electricity generation from renewables is expected to increase as at least 20 U.S. states have passed either legislation or executive orders to achieve carbon-free electricity in the next 20 to 50 years [187]. To analyze the effects of electric grid makeups with a higher percentage of renewables, we evaluate two theoretical electric grid scenarios, based on the U.S. EIA Annual Energy Outlook (AEO) 2021 projections [188], and apply them to the current industrial boiler population. The first grid scenario is based on the AEO reference case in 2050, and the second grid scenario, on the low-cost renewables and low oil and gas supply cases in 2050 (see Appendix B for further details on electric grid scenarios and AEO projections). For each scenario, the electric grid mix by source is shown in Figure 4-8(a), and the percent change in electricity generation by source from current levels is shown in Figure 4-8(b). The high renewables scenario used in this analysis does not reflect the exact AEO 2050 grid mixes and does not reflect any specific policies.

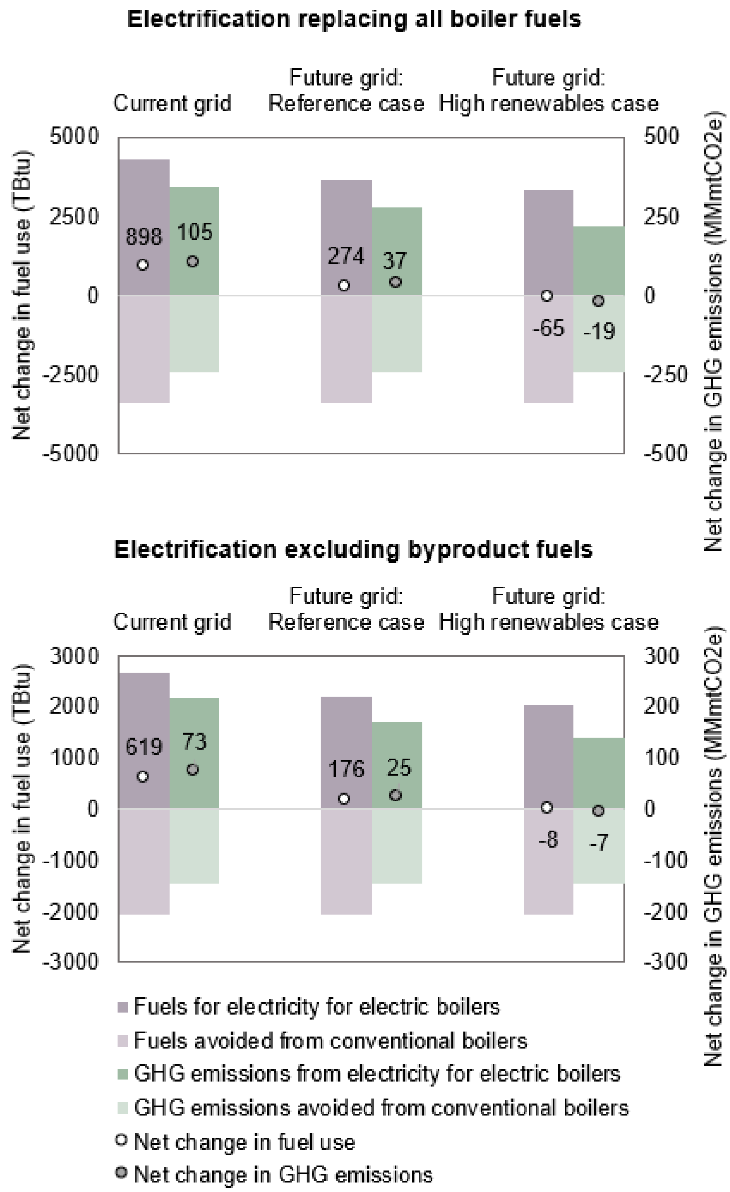
Despite a considerable increase in renewables and a 40% decrease in coal-based electricity in the reference grid case, when applied to the current boiler population, the fuels required for electricity from boiler electrification still exceed the fuel savings from conventional boilers (Figure 4-8(c)). Consequently, in this future reference case and under the current grid, there are more GHG emissions released at the nationwide level as a result of boiler electrification. GHG emissions would increase by 105 MMmtCO_2e under the current grid and 37 MMmtCO_2e under the future reference grid. The effects of increased fuel use and GHG emissions also occur under the current grid and future reference grid when boilers using byproduct fuels are excluded from electrification, although the additional required fuels and resulting GHG emissions are lower due to a portion of boiler energy demand being met by the existing byproduct fuels.


0.6%
0.1%
0.1%
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
Electric grid mix
17.6%
19.6%
23.3%
38.4%
41.1%
11.9%
11.7%
35.2%
54.6%
11.0%
11.7%
22.5%
Natural gas
Coal
Nuclear
Renewables
Oil
Current grid (2019)
Future grid: Reference case
Future grid: High renewables case
Electric grid carbon intensity
391 $kgCO_2/MWh$
247 $kgCO_2/MWh$
204 $kgCO_2/MWh$

(a)


Future grid: Reference case
Future grid: High renewables case
Natural gas
Coal
Nuclear
Renewables
Oil
10
-40
-27
180
-80
-100
0
100
200
Percent change in electricity generation
-30
-40
-33
270
-80
-200
0
200
400
Percent change in electricity generation

(b)



(c)

Figure 4-8. (a) Electric grid mix (percentages) and carbon intensity ($kgCO_2/MWh$) for the current grid and future cases. **(b)** Percent change in electricity generation of two future grid scenarios: reference case and high renewables case (combination of low-cost renewables case and low oil and gas supply case). **(c)** Estimated net changes in fuel use and GHG emissions from electrifying the current boiler population under the current electric grid, reference case grid, and high renewables case grid.

An overall reduction in fuel use and GHG emissions occurs only in the high renewables grid scenario, where electricity from coal and natural gas are reduced by 40% and 30%, respectively.

In this case, GHG emissions savings are 19 MMmtCO2e, which amounts to 3% of onsite emissions from the current U.S. manufacturing sector (609 MMmtCO2e) [7]. Similarly, in the high renewables case, when byproduct fuels are excluded, there is an overall reduction in fuel use (8 TBtu) and GHG emissions (7 MMmtCO2e). The share of coal and natural gas in the electric grid mix contributes most to the disparate outcomes in GHG emissions, with the share of coal having a greater influence on GHG emissions due to its higher carbon intensity compared to natural gas.

While electrifying boilers would currently lead to an increase in GHG emissions overall under current grid assumptions, there are counties in the U.S. where the adoption of electric boilers would lead to reductions in GHG emissions today (Figure 4-9). These counties are primarily in California, New York, and the Northeast, which represent the three subregions of the U.S. electric grid with the highest mix of clean electricity and lowest carbon intensity [189]. In some counties within these subregions, there are greater reductions in GHG emissions than others, which can be attributed to the level of boiler fuel use and fuel savings in the county. However, in most counties (2835 of the 3050 counties with boiler fuel use), boiler electrification would currently lead to an increase in GHG emissions. This analysis assumes average emissions factors for fuels based on regional electric power generation, but future work should consider marginal electricity generation and emissions rates and more detailed grid modeling.

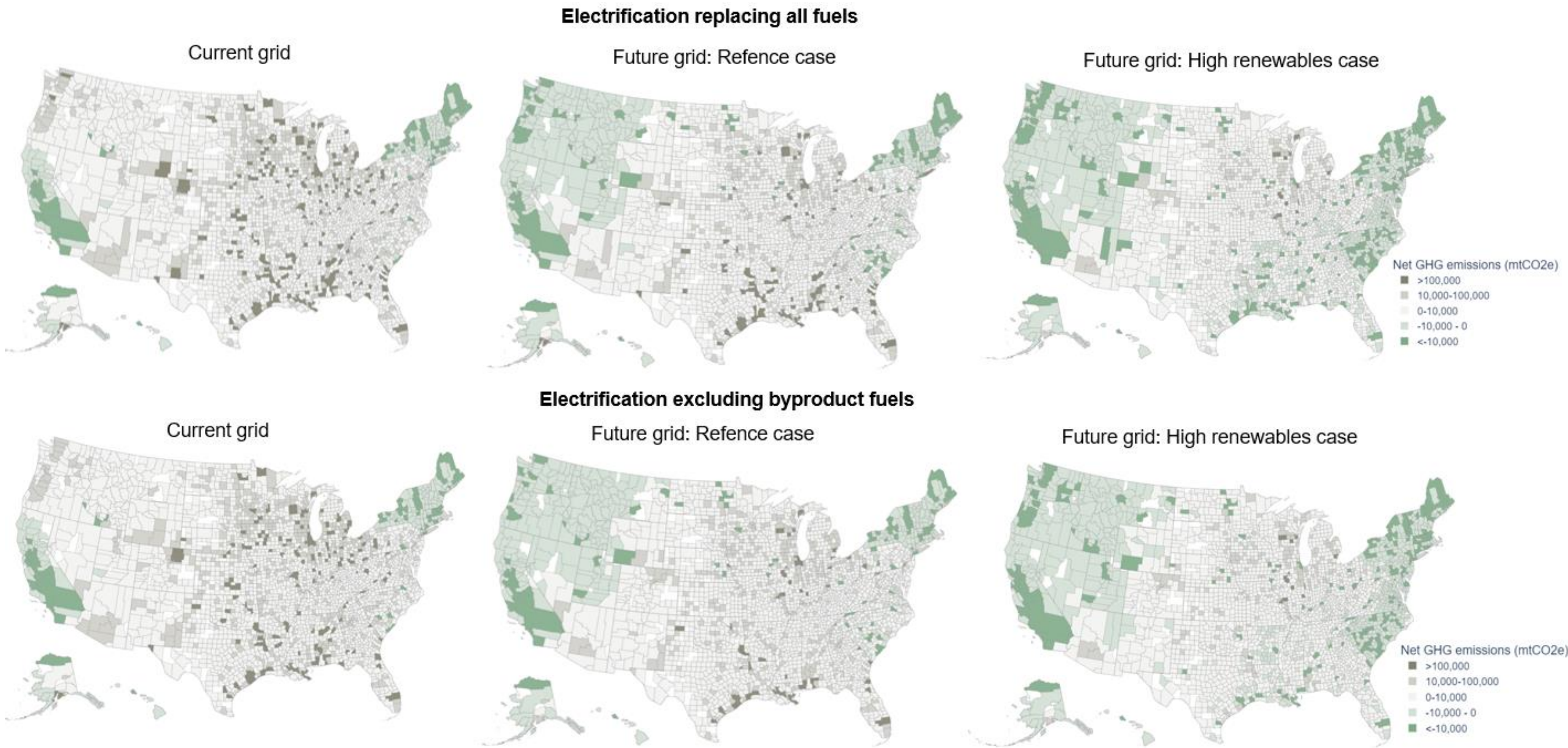


Figure 4-9. U.S. county maps of net changes in GHG emissions from boiler electrification under the current electric grid, reference case grid, and high renewables case grid

In the future reference case grid, where there is a considerable decrease in electricity from coal and slight increase in electricity from natural gas, there are additional counties in the Northwest and Southeast that show reductions in GHG emissions (516 counties with GHG emissions reductions in total when electrification replaces all boiler fuels). For instance, in several counties in the Northwest and West, which rely less on natural gas and more on coal for electricity, the net GHG emissions become negative, indicating a reduction in emissions. With a reduced mix of both coal and natural gas in the high renewables case grid, more counties throughout the country are shown have GHG emissions reductions (1103 counties in total when electrification replaces all boiler fuels).

In this regard, our study is consistent with past work [155]–[158] but expands the focus in the US, considering the boiler population per county and the effects of the fuel mix in the grid on emissions. In particular, this work emphasizes the need for reducing emissions in the life cycle of electricity generation, such as upstream natural gas leakage [190], the adoption of clean generation technologies, including carbon capture and sequestration (CCS) in coal and natural gas power plants, and increasing the share of renewable and nuclear electricity generation. Furthermore, energy efficiency measures that reduce steam demand could make electrification more favorable and improve the overall investment economics considerably [191]–[193]. A facility-level economic analysis could incorporate the effects of efficiency gains and other non-energy benefits and expand on previous work that has demonstrated methods for calculating economic parity for electric boilers [194].

4.4 Conclusion

The electrification potential of industrial boilers and the GHG emissions impact of their electrification are affected significantly by the current population of boilers, county-level boiler fuel consumption, and the fuel mix of the electric grid. The up-to-date industrial boiler dataset developed in this work characterizes boilers by county, manufacturing subsector, installed capacity, and fuel type, identifying trends in boiler size and fuel types that can aid the transition to low carbon heat technologies. Key findings from the electrification potential analysis show that the largest electrification potential of industrial boilers is in the chemicals, refining, and paper subsectors, when electrifying all conventional boilers, and the chemicals, refining, and food subsectors, when excluding boilers using byproduct fuels from potential replacement with electrification. Notably, electrifying boilers leads to an overall increase in national fuel use and GHG emissions based on the current national grid mix, but that in some U.S. counties where the regional electric grid has a low carbon intensity, boiler electrification would lead to a reduction in GHG emissions today. This analysis demonstrates the sensitivity of results to coal and natural gas use in the electric grid and, more broadly, the importance of accelerating grid decarbonization for industrial electrification technologies to result in net GHG emissions reductions.

Future research could incorporate data from other non-standardized sources. As an example, data science methods could be employed to extract boiler unit data from state air permits. Using these data would address the limitations in national-level equipment and emissions databases. Furthermore, the inclusion of additional unit characteristics, such as year of installation, from these data sources would better predict long-term decarbonization potential. Additionally, future research could address the significant electricity load additions from industrial electrification and integrate grid modeling that considers both electrification load and grid generation mixes in more temporal detail (e.g., hourly) and quantifies the marginal emissions to meet electric boiler loads. Future work could also consider heat pumps as an alternative electrified heating technology because they increase efficiency and could be enabled by the results of this study to assess the optimal deployment decisions for electric boilers and heat pumps. Finally, an economic analysis could investigate facility-level costs associated with the electrification of boilers, such as investment costs, operation and maintenance costs (e.g., regional fuel and electricity costs), and avoided mitigation costs.

Manufacturing facility decision makers and policymakers could consider several points of action based on the findings of this work. First, reducing steam demand in processes through efficiency measures could reduce the needed replacement capacities and improve economic feasibility. Second, potential economic co-benefits (e.g., reduced pollution abatement costs, smaller equipment footprints) could be quantified and accounted for, which could also improve economic feasibility. Third, for large boilers that are likely to continue combusting byproduct fuels, CCS could be implemented instead of stranding byproducts which may be combusted in another way.

5. Developing Datasets for Industrial Energy Modeling

This research explores data sources for the industrial sector and determines key data fields that should be included in industrial energy models. Building on previous work that characterized boilers in the U.S. industrial sector and integrated unit-level data from national emissions databases, this research covers 1) a detailed overview of common data sources used in industrial energy modeling in the United States, including their features and limitations, 2) further analysis of facility-level and unit-level data in national emissions databases, including the how unit-level material throughput and energy input can be derived, and 3) defining key data fields for industrial energy models, creating a nested structure of data fields, and building a preliminary industrial facility dataset. Ultimately, these research outcomes address the need for improved facility- and unit-level data in industrial energy models and analyses of industrial decarbonization.

This chapter is based on work completed at the National Renewable Energy Laboratory (NREL) in collaboration with Argonne National Laboratory (ANL) and is adapted from the following technical report, in preparation: McMillan, C., Supekar, S., Schoeneberger, C. "Foundational Industrial Data." National Renewable Energy Laboratory. 2023.

5.1 Introduction

Industrial energy modeling faces numerous challenges due to the sector's diversity of products, processes, technologies, energy sources, energy prices, supply chains, and markets, especially in manufacturing and more so when including its other sectors – mining, construction, and agriculture. Beyond the complexity of modeling the relationships among these factors, it is often difficult to simply obtain accurate industrial data to populate models. One reason is that industrial companies consider operational energy and economic data to be proprietary and are reluctant to release it. Another is that government regulations that attempt to mandate reporting from industrial facilities have limitations in consistency and reach. First, regulations themselves can be inconsistent over the years due to changes in presidential administrations. For example, the Clean Power Plan was announced in the U.S. in 2015 to curb CO_2 emissions from power plants but was repealed in 2019 [195]. Second, data that is collected by government agencies can be limited by the erratic nature of compiling data entries from thousands of different facilities and tens of different state and local agencies. Third, while government data does widely serve as useful primary sources of industrial data, despite the drawbacks in collection, there is often dissonance among various overlapping datasets, and interpreting and applying such data to energy models requires thorough analysis.

Industrial energy modeling is used to understand relationships between energy resources, industrial operations, environmental impacts, and economic factors and is extremely useful for evaluating pathways for sector-wide decarbonization. The outputs of these models typically lead to projections of energy demand, cost minimization, or evaluations of climate change mitigation scenarios [196]. In general, energy models fall into a range of high-level categories: top-down, bottom-up, and hybrid models. Within each category, there can be further classifications, where top-down models consist of input-output (IO) models, integrated assessment models (IAMs), and general and partial equilibrium models, and bottom-up models consist of linear programming or nonlinear programming models [197].

Each of these types of models can be applied at different scales, from sub-national to global. For instance, GCAM is a widely used IAM developed at Pacific Northwest National Laboratory (PNNL) that uses market equilibrium principles to equate supply and demand across the energy system and economic sectors with a global scope [198]. As an example of another top-down model but with a national scope, the USEEIO is an IO model developed by the U.S. Environmental

Protection Agency (EPA) that maps the impact of economic activities between industries along with environmental data on land use, water, energy use, and pollution [199]. Additionally, the National Energy Modeling System (NEMS) is a market equilibrium model for the U.S. that the Energy Information Administration (EIA) uses to project the production, consumption, and prices of energy, subject to macroeconomic factors, resource availability, and consumer behavior, among others variables [200].

While the top-down models are useful in accounting for important sector-to-sector interactions, bottom-up models describe energy systems with technology-rich detail, emphasizing accurate representation of energy use by technologies and allowing for more granular scenarios, such as efficiency measures and process switching. As an example of a widely used global bottom-up model, the TIMES model developed under the International Energy Agency (IEA), and derived from its precursor, MARKAL, consists of energy and emissions control technologies that each have performance and cost factors and is designed to minimize energy system cost [201]. Similar to GCAM, it is based on a market equilibrium design where energy production is matched with energy consumption [201]. The U.S. EPA uses TIMES in conjunction with its EPAUS9rT database, which is used to analyze environmental impacts of policy, technological, and behavioral changes within the U.S. energy system [202]. In addition to TIMES, the IEA uses its own GEC model, based on its previous ETP model, which was a technology-centric bottom-up model, to project medium and long term energy outlooks. The GEC model is a bottom-up partial optimization model that covers 26 regions across the globe, separately or aggregated, to project technology stock, cost, and performance, energy flows, investment costs, materials demand, and GHG emissions [203].

Many of these models use similar variables (e.g., technology stock, fuel type, energy consumption by end-use or process, energy price) that rely on accurate industrial data. It is important that energy models covering the industrial sector both routinely incorporate the key variables that represent the sector and use the best available data as inputs. Ultimately, this research addresses these challenges by exploring publicly available industrial data in the U.S. and proposing a structure of data fields that future industrial energy models can use.

5.2 Data Sources

There are numerous databases maintained by U.S. government agencies that serve as primary data sources for the industrial sector and provide data related to location of industrial facilities, pollutant and GHG emissions, energy consumption and generation, employment size, and macroeconomic trends. Several of the most frequently used databases with industrial data are listed and characterized in Table 5-1. These include the Facility Registry Service (FRS) [204], Greenhouse Gas Reporting Program (GHGRP) [205], National Emissions Inventory (NEI) [206], Toxics Release Inventory (TRI) [207], WebFire [208], Manufacturing Energy Consumption Survey (MECS) [209], Annual Energy Outlook (AEO) [210], Monthly Energy Review (MER) [211], U.S. Census Bureau County Business Patterns (CBP) [212], U.S. Bureau of Economic Analysis (BEA) Gross Domestic Product (GDP) [213], U.S. BEA Input-Output (IO) Accounts [214].

Government databases often contain multiple datasets that can be accessed individually according to the primary data they include. The datasets or data within these databases are often filtered and refined to capture data fields relevant to the particular study and are then supplied as inputs to models and analyses. Many models and analyses use data from multiple sources in parallel or merge them to achieve broader coverage, but because reporting timelines, collection methods, descriptors of data, and levels of North American Industry Classification System (NAICS) classification can vary, there are limitations and challenges with assembling quality data.

Table 5-1. Sources of U.S. industrial sector data

	FRS	GHGRP	NEI	TRI	WebFIRE	MECS	AEO	MER	CBP	BEA GDP	BEA IO
Publishing entity	EPA	EPA	EPA	EPA	EPA	EIA	EIA	EIA	Census Bureau	BEA	BEA
Reporting frequency	Week	Annual	3 years	Annual	Annual	4 years	Annual	Month	Annual	Quarter	Quarter
Data release delay	1 week	9 months	3 years	10 months	-	3 years	3 months	3 months	1.3 years	3 months	3 months
Reporting mandate	Within EPA	Required for high-emitting facilities	Required for state and local air agencies	Required for facilities with release of chemicals	Required for facilities with source test data	Survey	Within EIA	Within EIA	Required by Business Register	Within BEA	Within BEA
Data methods+	Complied	Compiled	Compiled	Compiled	Compiled	Statistical	Modeled	Complied	Complied	Compiled	Modeled
Data fields* *key fields, not complete list	FRS ID, Lat/Lon, FIPS, NAICS	GHG emissions, Unit capacity, Unit type, City/State, NAICS	Pollutants, GHG emissions, Unit type, Unit capacity, SCC, Emission factor, FIPS, NAICS	Chemical, Release amount, Release method, Lat/Lon, NAICS	Pollutant, GHG, SCC, Emission factor	Energy use, Feedstock energy, Fuel type, End-use, Region, NAICS	Projections of Energy use, Generation, Energy prices, CO2 emissions, Region, Future years	Energy use, Generation, Energy prices, CO2 emissions, Past years	Count of establish-ments, Count of employees, Payroll, Zip code, NAICS	Gross output – quarterly, Industry subsector	Supply, use, and imports of commod-ities
Sector coverage	All industry, 6-digit NAICS	All industry, 6-digit NAICS	All industry, 6-digit NAICS	Manufacturing, some agriculture and mining, 6-digit NAICS	All industry, by processes	Manufacturing sector, 6-digit NAICS	All industry, 3-digit NAICS for manufacturing	Industrial sector total	All industry, 6-digit NAICS	All industry, 3-digit NAICS	All industry, 3-digit NAICS

+ For data methods, "compiled" implies the published data is from reported entries or surveys; "statistical" implies the published data is the result of statistical analysis to form a complete dataset; "modeled" implies the published data is forecasted or calculated.

The GHGRP and NEI are examples of databases that have operational data tied to individual process units within industrial facilities, but extracting data from either separately or combining their data presents challenges due to differences in coverage and collection. For instance, the GHGRP requires only facilities emitting greater than 25,000 tCO_2e and suppliers of fossil fuels and industrial gases, amounting to about 8,000 facilities, to report emissions data. Overall, it is estimated that the emissions accounted for in GHGRP data cover roughly 85% of total U.S. GHG emissions, which include power plants, manufacturing, and fuel supply in transportation and buildings, but not agriculture or land use [215]. However, there is inherent variability in reported emissions, as facilities and suppliers may estimate emissions by one of five different methods, which include continuous emission monitoring systems, measured fuel consumption data, or default emissions factors [216]. Although GHGRP data captures large facilities, where most emissions are concentrated, it fails to capture unit data for the majority of industrial facilities, of which there are over 200,000 [212]. Some of the same industrial units in the GHGRP are also in the NEI, but each database uses its own facility ID code, and while there are indirect crosswalks between ID codes, they are not fully inclusive.

The NEI does collect data on more individual units than the GHGRP, regardless of size, because its data collection relies on submissions from state, local, and tribal (SLT) air agencies that have stringent emissions reporting rules. However, some states have different ways of classifying data fields or requirements for collecting certain types of data. Specifically, the "unit type" data field is classified differently across states; a boiler in one state could be labeled as an incinerator in another, and some states do not require unit type to be reported [217]. In the NEI, there are 88 different unit types for manufacturing industry data, of which over 40% of entries are "unclassified" or "other process equipment."

Other limitations in the NEI include the reliability and availability of key operational data. First, facilities use a variety of different methods used to estimate emissions, which lead to uncertainty in reported values. Figure 5-1 shows the count of emissions calculation methods used to estimate emissions in NEI data. In some manufacturing subsectors (pulp and paper, refining, and chemicals), "engineering judgement" is one of the most frequently used methods. Additionally, there can be errors in the emissions data field, where the correct emissions total is recorded by written text in another data field. These errors can arise because data is compiled from user entries from SLT agencies across the country. Second, NEI data includes unit capacity for applicable unit types, but capacity values are not reported in standard units and are also often found written in text in other data fields, such as unit description and process description. Third, the fuel type for applicable units is not recorded as an official data field but is also occasionally recorded in other fields.

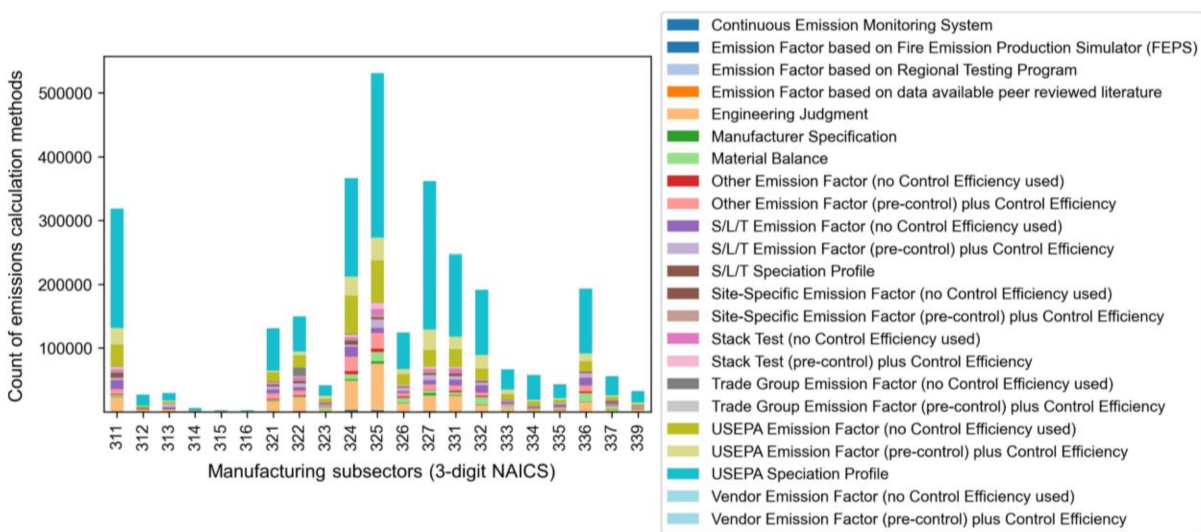


Figure 5-1. Distribution of emissions calculation methods by manufacturing subsector in NEI data

Despite limitations, both the GHGRP and NEI remain essential resources for facility- and unit-level industrial data, and applications in this research are further discussed in the next section.

5.3 Facility- and Unit-level Analyses

The FRS database contains geospatial data on all facilities reporting to the EPA and can be used to link unrelated EPA databases to each other, provided that they include an FRS ID, and to serve as a comprehensive list of almost all industrial facilities. Notably, FRS data contains the latitude and longitude of facilities, in addition to facility name and NAICS code, allowing for more detailed locational data compared to other datasets which only report state or county. Figure 5-2 shows a map of manufacturing facilities in a region near Evanston, IL that have reported to the U.S. EPA and been assigned an FRS ID; the highlighted facility is an example of a fluid milk manufacturing site (NAICS 311511).

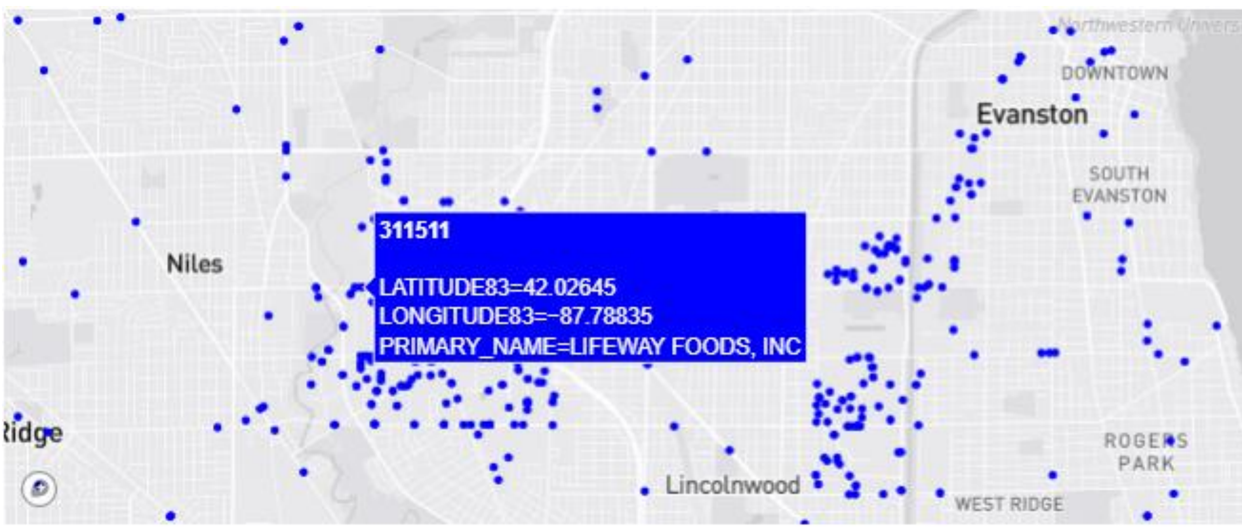


Figure 5-2. Map of facilities in the U.S. EPA FRS dataset within the manufacturing sector (NAICS 31-33), zoomed in on the region near Evanston, IL.

The level of locational detail in the FRS is useful because industrial facilities can be easily linked to other energy, environmental, and socioeconomic data. These connections are especially important for the industrial sector, whose point sources of fuel combustion, process emissions, and other chemical releases have led to localized pollution and public health issues [218], [219]. The connection between location of industrial facilities, amounts of pollution, and demographics of nearby communities are particularly useful to studies of environmental justice (EJ), as research has shown that there are disparities in air pollution exposure by race or ethnicity and income [220]. The U.S. EPA maintains a tool, called EJScreen, that combines environmental and demographic socioeconomic indicators by areas of the country [221], and this industrial data could be paired with EJ indexes. FRS industrial data could also be overlayed with numerous other spatial energy and infrastructure data, such as renewable resource availability, existing electrical infrastructure, and CO_2 and hydrogen pipeline networks.

The coverage of industrial facilities in the FRS is well represented compared to the total estimated number of industrial establishments in the country, specifically for the manufacturing sector. Table 5-2 shows that for the industrial sector as a whole, which includes agriculture, mining and oil and gas extraction, construction, and manufacturing, the FRS covers about 41% of estimated establishments accounted for in the Census CBP data. For the manufacturing sector on its own, the coverage is exceptionally high, 95%, but the comparison between totals within each manufacturing subsector (3-digit NAICS) is not uniformly high, and in some cases the number of facilities in the FRS overshoots the number in CBP data (see Figure 5-3). For these cases, it is possible that some facilities in FRS data are no longer in operation and do not appear in CBP data but remain in the FRS database. FRS data is updated monthly but may not regularly remove facilities.

Table 5-2. Number of facilities in EPA FRS data (2022) compared to the best estimate of total industrial establishments, from Census Bureau CBP data (2021)

	EPA FRS facilities	**CBP establishments**
Industrial sector (NAICS 11, 21, 23, 31-33)	451,641	1,088,331
Manufacturing sector (NAICS 31-33)	271,683	285,452

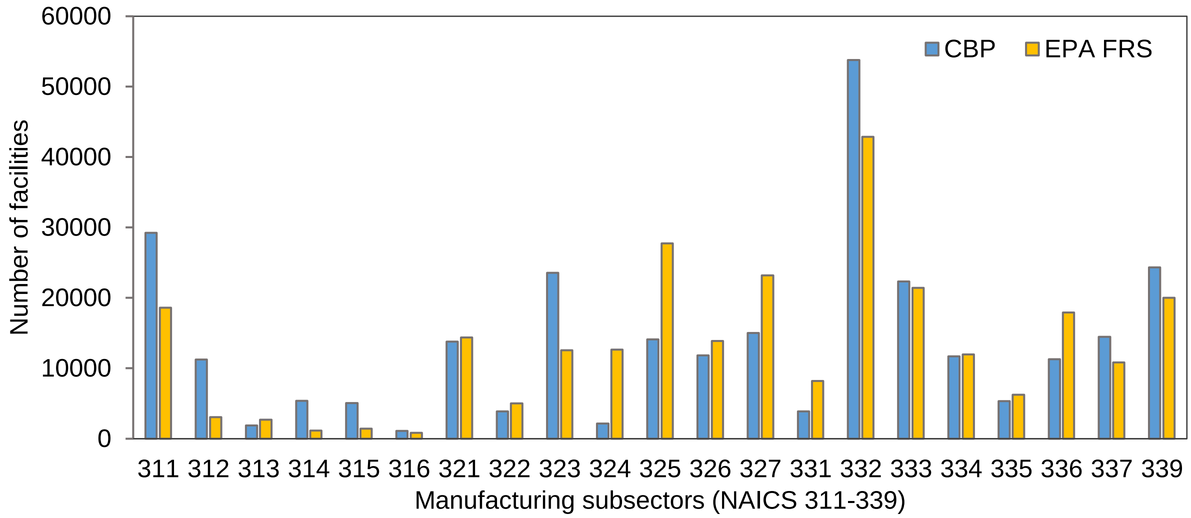


Figure 5-3. Number of facilities in EPA FRS data and Census Bureau CBP data for the manufacturing sector (NAICS 31-33).

While the FRS database serves as a comprehensive source of facility-level data, the GHGRP and NEI databases contain unit-level operational data via emissions totals and unit capacity. Both databases classify units according to unit type, which provides a basis of process data for bottom-up energy modeling. An analysis of total number of units by unit type, GHG emissions by unit type, and total capacity by unit type for each facility shows the distribution of unit processes in a given industry and can be used to build a representative energy model for an industry. Appendix C has figures from this analysis for several manufacturing industries. The scope of this work explores the coverage of unit type data in the GHGRP and NEI, but future work could pair existing facility and unit data with statistical or machine learning methods to fill the gaps of units not accounted for in these emissions databases.

5.4 Deriving Material Throughput and Energy Input

Emissions data in the GHGRP and NEI not only reports pollutant type and annual emissions amounts but can also provide insights on other operational data for facilities and units. In this research, emissions data is used to derive material throughput and energy input for facilities in the

NEI. The methods involve filtering units by specific pollutant types, adding emissions factors from WebFIRE data where NEI emissions factors are insufficient, determining fuel types for combustion units, and calculating values for throughput and energy. A process flow chart displaying the full set of methods is shown in Figure 5-4.

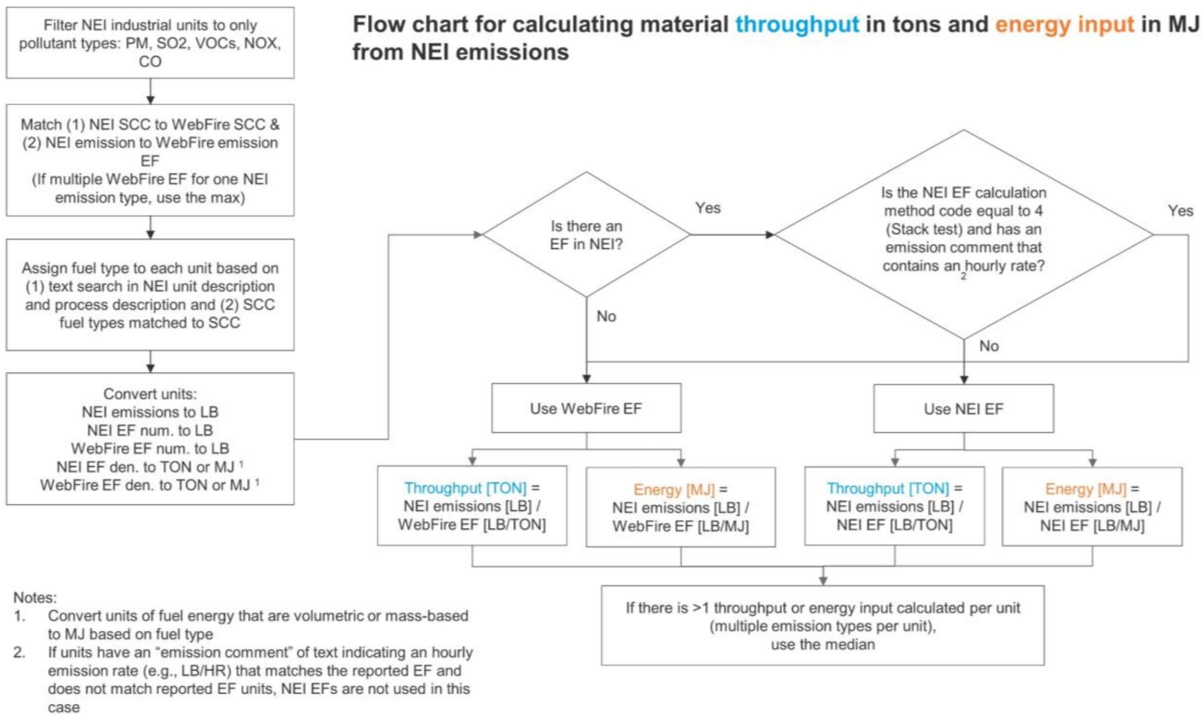


Figure 5-4. Methods to calculate material throughput and energy input from emissions data in the NEI

A specific set of pollutant types – particulate matter (PM), sulfur dioxide (SO_2), volatile organic compounds (VOCs), nitrogen oxides (NOx), and carbon monoxide (CO) – are filtered and used in the calculations because they are the most monitored and reported pollutant types in the NEI and are expected to yield the most accurate estimations. Although every unit in the NEI reports an emissions amount, there is not always a reported emissions factor. To make up for the omission, emissions factors from WebFIRE are merged into NEI data based on matching SCC codes. As mentioned in Appendix C, the NEI contains SCC codes as another form of unit type or activity releasing emissions [222], and WebFIRE emissions factors are identified by SCC codes. For emissions factors with an amount of pollutant emissions per mass, throughput is calculated; for emissions factors with an amount of pollutant emissions per energy or volume of fuel, energy input is calculated. The calculation for throughput and energy input are completed by dividing the emissions amount by the associated emissions factor. Lastly, for units where multiple pollutants are reported and, therefore, multiple values for throughput or energy are calculated, the median value is used.

For all the units in the NEI with PM, SO_2, VOCs, NOx, and CO emissions, throughput is calculated for 27%, and energy input is calculated for 20%. The percentage calculated differs by industrial subsector, and the breakdown is shown in Appendix C. This analysis represents an initial step towards developing facility- and unit-level data derived from primary sources in industry, and future work could extrapolate unit data within industries of similar size to get a full representation of industrial sector processes.

5.5 Data Fields for Industrial Facility Dataset

Several national energy models specific to the industrial sector were reviewed in order to identify a common set of data fields used as inputs that could serve as standard fields for future modeling efforts. The reviewed models were the Industrial Sector Technology Use Model (ISTUM) [223], [224], a precursor to NEMS, and the UK Energy Research Centre Usable Energy Database [225]. The types of data used in these models cover general energy flows (e.g., purchased fuels, grid electricity, final energy demand), baseline technology data (e.g., technology description, energy inputs and outputs, fuel-related and process emissions, fuel efficiency, size range, hours of operation, applicable industries), technical and market limitations for new technologies (e.g., TRL, maximum technical potential, current level of adoption, degree of technological change), and cost information (capital investments, operations and maintenance, lifetime, available space/land).

Based on this review, key data fields are identified, and a hierarchal structure for assembling data is proposed (Figure 5-5). The data hierarchy is meant to serve as the basis for developing an industrial facility dataset for the US, which utilizes the previous analyses in this research. For example, much of the data in the top level of site information, describing the location of facilities and links to other spatial datasets, and the facility level, identifying the facility and its industry, can be provided by FRS data. Furthermore, many data fields for unit operations can be filled with GHGRP and NEI unit data. The major process level represents the grouping of individual unit operations and, in some cases, the level at which a potential decarbonization technology may be substituted. For example, hydrogen production in ammonia manufacturing is considered a major process, whereas steam methane reforming, separation, and compression are unit operations.

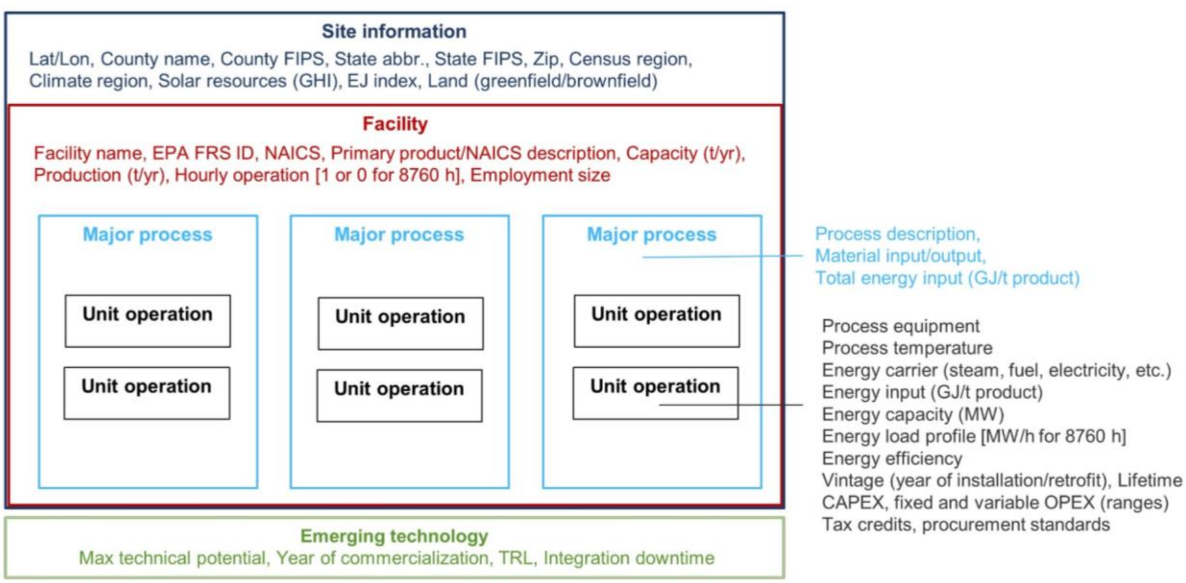


Figure 5-5. Data fields in hierarchal structure for developing an industrial facility dataset

5.6 Future Research

There are several areas for future work related to unit operations analysis with NEI and SCC data and to expanding the industrial facility dataset based on the preliminary data structure that was created. First, many of the units in the NEI have unit types categorized as "Unclassified," and while each unit has an SCC code, there are not concise and categorized unit type descriptors for the 8,000 different SCC codes. Defining a set of unit type descriptors that encompasses all SCC codes would be extremely useful in further evaluating the types of units in industrial facilities. Second, when evaluating NEI data for unit types and emissions factors, it was found that some data fields contain written text that states the hours of operation. This is a key data field for industrial energy analysis that is typically not reported, especially on an individual facility basis. This hours of operation data could be extracted from the NEI and supplied in the industrial facility dataset in development. Third, the NEI has released data every three years since 2008 and in varying intervals between 1990 and 2005. A time series analysis of emissions and unit type data could identify trends in energy usage, technology adoption, and emissions totals over time. It could also provide insights on the year a facility began operation or year of unit installation, which are key variables for modeling the adoption of decarbonization technologies. Lastly, an analysis evaluating whether there are differences in emissions per similar units between states could show the effects of different policies or cost factors that could influence future decarbonization efforts.

6. Technical, Environmental, and Economic Modeling Framework for Decarbonized Process Heat in Plastics and Ethylene Manufacturing

This chapter describes a modeling framework for evaluating energy, environmental, and economic impacts of low carbon process heat options in chemicals manufacturing. Specifically, it provides background on industrial process heat demand in U.S. chemicals industries and examines electrification and clean hydrogen for process heating in two case studies: plastics and ethylene manufacturing. This research extends previous work on the potential of boiler electrification from Chapter 4 and quantifies greenhouse gas (GHG) emissions, water consumption, and the levelized cost of heat (LCOH) of electric boilers, heat pumps, hydrogen boilers, electric steam ethane crackers, and hydrogen-fueled steam ethane crackers and compares results to conventional process heat technologies. The results illustrate that low carbon technology costs remain a significant barrier, primarily due to electricity and hydrogen prices, and identify these factors as targets for policies.

This chapter is adapted from the following manuscripts in preparation:

- Schoeneberger, C., Dunn J.B., Masanet, E. Technical, Environmental, and Economic Analysis Comparing Low Carbon Industrial Process Heat Options in U.S. Chemicals Manufacturing Facilities. *In preparation.*
- Jin, E., Jabarivelisdeh, B., Schoeneberger, C., Dunn, J.B., Christopher, P., Masanet, E. Critical Perspectives on Decarbonization Pathway Modeling for the Chemical Industry. *In preparation.*

6.1 Introduction

In the US, industry is responsible for the most GHG emissions of economic end-use sectors (1,909 $MMtCO_2e$ in 2021), surpassing transportation (1,810 $MMtCO_2e$), commercial (972

$MMtCO_2e$), residential (954 $MMtCO_2e$), and agriculture (672 $MMtCO_2e$) [226]. Despite advancements in decarbonization technologies in other sectors, the industrial sector has frequently been termed “hard-to-abate” because it has a diverse assortment of industrial processes with both combustion and process emissions, high-cost equipment with long lifetimes, and competitive international markets for its products [4]. However, a large portion of U.S. industry’s energy consumption is attributable process heating in manufacturing. The U.S. Department of Energy (DOE) has recognized the opportunity for reducing industrial emissions by targeting process heat and has created an “Industrial Heat Shot,” which aims to develop cost-competitive low carbon heat technologies with 85% GHG emissions reductions by 2035 [6].

Although there are several common conventional heat generation technologies across industries, industrial processes requiring heat vary widely by industry in terms of their required temperatures and capacities, making it difficult to identify feasible low carbon technology options. Furthermore, detailed data of process-level energy use for industrial heating is often scarce. To date, research on industrial heat decarbonization has approached these challenges by covering specific industries and technologies, such as electric heat pumps in food industries [227]–[229] and fuel switching and carbon capture and storage (CCS) in cement and glass [230], [231], steel [232], and other heavy industry [17]. Electrification and low carbon hydrogen have emerged as promising options for decarbonizing process heat, particularly in heavy industry such as chemicals [12], [233], but many studies provide broad potential assessments rather than process-level analyses. Other research in this area has led to the development of facility-level datasets when relevant industrial data has not been readily available [23], [138] and to expansive R&D road maps [15], [16], [18]. Despite this breadth of research, few studies have: 1) directly analyzed process heat in some hard-to-abate industries like chemicals, 2) assessed multiple low carbon technologies in the same study, and 3) employed a bottom-up process-level modeling approach. These analysis needs are further outlined in the U.S. DOE Industrial Decarbonization Roadmap, which calls for analysis of low carbon process heat solutions that describes key technical characteristics and case studies, especially for electrification and hydrogen to achieve net-zero ambitions by mid-century [18].

Acknowledging both sector-wide challenges and research gaps in process-level industrial heat analysis, this study evaluates emerging low carbon technologies for industrial heat applications and provides assessments of environmental impacts and costs. In this research, we focus on chemicals manufacturing, which has the highest energy consumption and energy-related carbon dioxide emissions within the U.S. manufacturing sector [234] [235].

In the U.S. chemicals sector, the majority of onsite energy consumption is for process heating, which occurs primarily in direct-fired fuel combustion processes and steam-based processes [236]. Overall, natural gas and waste gases, which are byproduct gases from other processes, are the main fuels used in combustion equipment, including boilers, combined heat and power (CHP) units, and furnaces [236]. However, there are hundreds of thousands of chemicals produced and sold commercially [237], and for many unit processes in their production, there are significant differences in the magnitude of energy demand, process temperature, heat energy carrier, and mix of fuel use. In the US, similar chemicals are grouped in classifications according to the North American Industry Classification System (NAICS). shows the estimated thermal energy use by chemical industry and NAICS code, with their energy use broken down by process temperature.

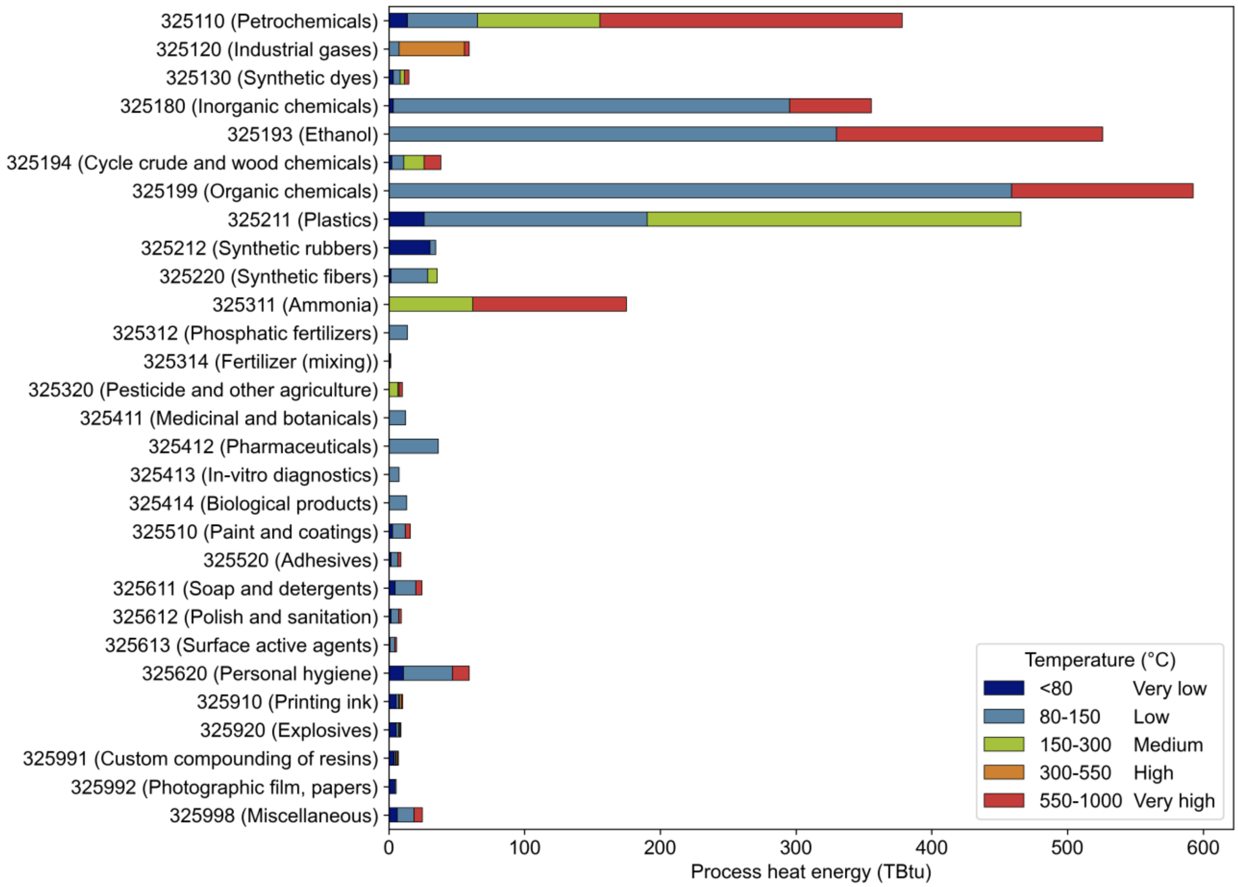


Figure 6-1. Process heat energy (TBtu) of chemicals industries according to their NAICS code and temperature range of heat demand in 2014. Data from [238].

Six industries – organic chemicals, ethanol, plastics, petrochemicals, inorganic chemicals, and ammonia – collectively have by far the highest energy consumption for process heating. While some industries are dominated by a main chemical product, such as ethanol and ammonia, others have numerous chemical products that make up its heat energy demand (see Table D-0-1 for a list of chemicals by industry). Most ethanol in the U.S. is produced by bio-based routes using biomass feedstocks [239]. Ammonia, whose main energy-consuming processes are from the production of the feedstock hydrogen and reactor heating, has been the subject of numerous decarbonization research efforts to date [240]. In the other energy-intensive industries, there is a mix of high temperature (>550^{o}C) and low to medium temperature (<300^{o}C) processes requiring heat. The plastics and petrochemicals industries have contrasting heat demand requirements, with plastics having low to medium temperature heat and petrochemicals having the biggest share of high temperature heat. These two industries are selected as case studies for this analysis.

In particular, this study compares conventional process heat technologies to several low carbon technology pathways – the electrification of heat by electric boilers, industrial heat pumps, and electric steam ethane crackers, and the use of clean hydrogen for process heat – in two energy-intensive chemical industries, plastics and petrochemicals. Using a combination of life cycle assessment (LCA) and techno-economic analysis (TEA) metrics, this study quantifies the GHG emissions, water use, and lifetime costs of these technologies under different scenarios. Key cost parameters are further identified in sensitivity analyses, and barriers associated with new technology adoption are discussed. As the U.S. undergoes energy transitions, especially in the power sector and with the emergence of a hydrogen economy, this work provides a technical, environmental, and economic framework for evaluating low carbon process heat technologies and technical case studies that can be used by industrial facility decision makers and policymakers to aid the deployment of low carbon process heat technologies.

6.2 Methods

The objectives of this analysis include identifying energy-intensive industries and unit processes, determining feasible low carbon technology solutions for select process heat applications, and calculating the energy, environmental, and cost metrics for each technology case at the facility-level. The scope of the analysis covers process heat applications in the plastics and petrochemicals industries in United States, but the technical, environmental, and economic framework could be applied globally and in other industries. This section further describes the selection of case studies, system assumptions, and calculations.

6.2.1 Low Carbon Process Heat Technology Case Descriptions

Much of the low to medium temperature process heating demand in the plastics industry is met by steam from boilers and CHP units (see Appendix D) for use in unit processes like reactors and drying. Steam from CHP units makes up a large portion of total industry onsite energy use, but the number of CHP installations for the industry reported in the DOE CHP database is 30, whereas there are over 1,100 plastics manufacturing establishments in the country [241], [176]. Among the plastics production facilities reporting emissions from boilers and CHP units in the National Emissions Inventory database [242], less than 5% of the units are CHP (Figure D-0-2). While a small number of CHP units may provide large amounts of energy in some plastics production facilities, decarbonizing heat from CHP by fuel switching or electrification is more complex physically and economically because of the concurrent electricity generation. The reliability of power supply and reduction in energy costs that CHP can provide to facilities add extra barriers for implementing near-term low carbon technologies. For this reason and the fact that conventional boilers are widely used and present in most facilities, we consider low carbon technologies that substitute steam generation from only conventional boilers.

Steam generation for industrial process heating can be potentially met by several electric technologies, including electric boilers and industrial heat pumps. Both are commercially available with a technology readiness level (TRL) of nine and can achieve high capacities and desired process temperatures [243]. Electric boilers work by sending an electric current through water between electrodes (electrode boilers) or through immersed heating elements (electric resistance boilers) [244]. Industrial heat pumps operate by using electricity as work to move heat from low temperatures to high temperatures, and high temperature heat pumps (HTHPs) now have heat sink temperatures that can reach up to 160-180^{o}C [245]–[248], which is applicable to much of the heat demand in chemical industries. Electric heating technologies can have co-benefits, such as the elimination of pollution control equipment for combustion gases and permitting costs; however, we do not quantify their individual impacts in this analysis but do account for differences in capital and operating costs.

Another low carbon process heat solution for industrial steam generation is replacing natural gas with clean hydrogen as a fuel source, either via blending or full substitution. Hydrogen has been suggested as a low carbon fuel source for medium to high temperature process heat in the industrial sector [18]. There are few analyses of hydrogen-fired or hydrogen-blended boilers in literature, but manufacturers have developed industrial boilers that run on hydrogen [249], [250], and researchers have studied the physical effects of hydrogen combustion, finding that combustion equipment can operate with hydrogen blends up to 30% by volume [251]. Hydrogen-blending in natural gas pipelines has been considered as a broad decarbonization solution in many countries, including in parts of the U.S. [252], but several concerns with hydrogen use have been documented, including hydrogen leakage, nitrogen oxides (NOx) emissions, and embrittlement of metals [253], [254]. Hydrogen-only boilers face the same challenges as well as others, including the need for larger pipes and metering stations and retrofit modifications to fans and burners [255]. Despite these side effects, as applications for hydrogen continue to grow in the U.S. due to the recently passed Infrastructure, Investment and Jobs Act (IIJA) and Inflation Reduction Act (IRA) [256], it is worthwhile to evaluate its potential in industrial applications.

In the petrochemicals industry, high-temperature heat demand is predominantly met by direct-fired fuel combustion (see Appendix D.2) and is concentrated in a number of energy-intensive processes. One of the most energy-intensive processes in petrochemicals is the steam ethane cracking process to produce ethylene from natural gas feedstock [257]. Ethylene is the most produced petrochemical by mass in the U.S. (see Appendix D.2) and a precursor to plastics and other specialty chemicals. In ethylene facilities, it is common to use waste gases, or refinery fuel gas (RFG), as fuel for crackers, so this analysis considers a second conventional cracker case, where 30% of the input fuel is RFG.

Both electrification and hydrogen have potential to decarbonize ethylene production. Electric crackers could supply heat in the process of converting ethane to ethylene by applying a direct current to process tubes and with radiative heating elements placed around the tubes [258],[259]. In two ongoing partnerships, major petrochemical producers are developing electric crackers at scale. Dow and Shell have run pilot scale units for electric steam cracking [260], and BASF, SABIC, and Linde are currently constructing a demonstration plant in Germany [258]. One concern with electrified technologies that operate continuously like ethane crackers is the reliability of the supply of electricity from the grid, which makes grid resilience and flexibility a key factor in electric technology adoption [261]. Using hydrogen as the fuel in crackers is another decarbonization option for ethylene production. An industry consortium in Europe has studied the combustion behavior, heat transfer, and safety of hydrogen combustion for high-temperature process heat [262]. And in the US, ExxonMobil is currently planning to produce blue hydrogen to fuel its ethylene plant in Baytown, Texas [263].

Table 6-1 shows the process heat technologies evaluated in this analysis and the main descriptors of each technology case. It is assumed that each technology case is a new installation and that all energy sources (natural gas, electricity, hydrogen) are purchased except for refinery fuel gas, which is an onsite byproduct. Green hydrogen is produced from the electrolysis of water using renewable electricity, and blue hydrogen is produced from natural gas steam methane reforming with carbon capture.

Table 6-1. Case descriptions for process heat technologies. NG is natural gas; H2 is hydrogen; RFG is refinery fuel gas. SERC, RFC, and TRE are regional reliability entities for the U.S. electric grid.

	Process heat technology	Heat source	System assumptions
Case 1: Plastics production	Conventional Boiler	NG	Purchased NG
	Electric Boiler	Electricity	Grid, Louisiana (SERC)
		Electricity	Grid, New Jersey (RFC)
		Electricity	100% Decarbonized
	HTHP	Electricity	Grid, Louisiana (SERC)
		Electricity	Grid, New Jersey (RFC)
		Electricity	100% Decarbonized
	H2-NG Boiler	NG, H2	30% Green H2
		NG, H2	30% Blue H2
	H2 Boiler	H2	100% Green H2
		H2	100% Blue H2
Case 2: Ethylene production	Conventional Cracker	NG	Purchased NG
		RFG, NG	30% RFG
	Electric Cracker	Electricity	Grid, Louisiana (SERC)
		Electricity	Grid, Texas (TRE)
		Electricity	100% Decarbonized
	H2 Cracker	H2	100% Green H2
		H2	100% Blue H2

Multiple locations are considered in some of the technology cases due to regional differences in variables that affect environmental impacts and costs. For instance, the sources of electricity vary in regional electric grids, affecting emissions, water use, and electricity prices. The prices of natural gas and hydrogen also differ by region and are further discussed in Section 6.2.4. In the plastics production case, technologies are evaluated from the perspective of a facility located in Louisiana and New Jersey because there is a concentration of plastics facilities in both states. Figure 6-2 shows the location of individual facilities in the plastics and petrochemicals industries. In the petrochemicals case, this analysis considers ethylene production in Louisiana and Texas. While there are petrochemical facilities dotted across the country, 95% of the ethylene production capacity in the U.S. is located in Louisiana and Texas [264].

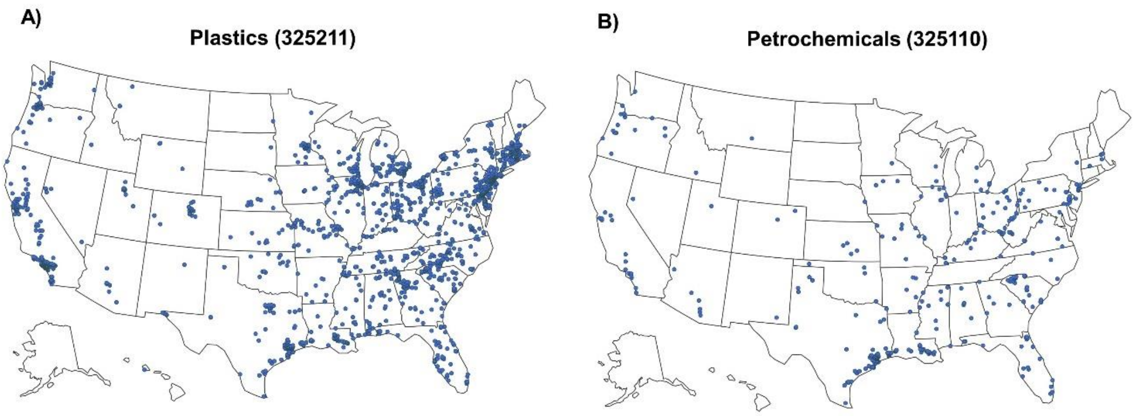


Figure 6-2. Location of facilities in the A) plastics (325211) and B) petrochemicals (325110) industries in the U.S. Data from [265].

6.2.2 Unit Process Energy

For each case study, unit process energy data is used to calculate the thermal energy demand that low carbon technologies would need to supply. Although there are many similar unit processes for chemicals production within the plastics industry, the particular thermal energy demand is different for each chemical product based on a variety of factors, including process temperature and energy carrier. Polyvinyl chloride (PVC) is selected as a representative chemical in the plastics industry. It has one of the highest production quantities among plastics in the U.S. (see Appendix D.2) and has steam demand with process temperatures achievable by industrial heat pumps. Figure 6-3 shows the unit process diagrams for PVC production and ethylene production, highlighting processes involving steam and fuel inputs.

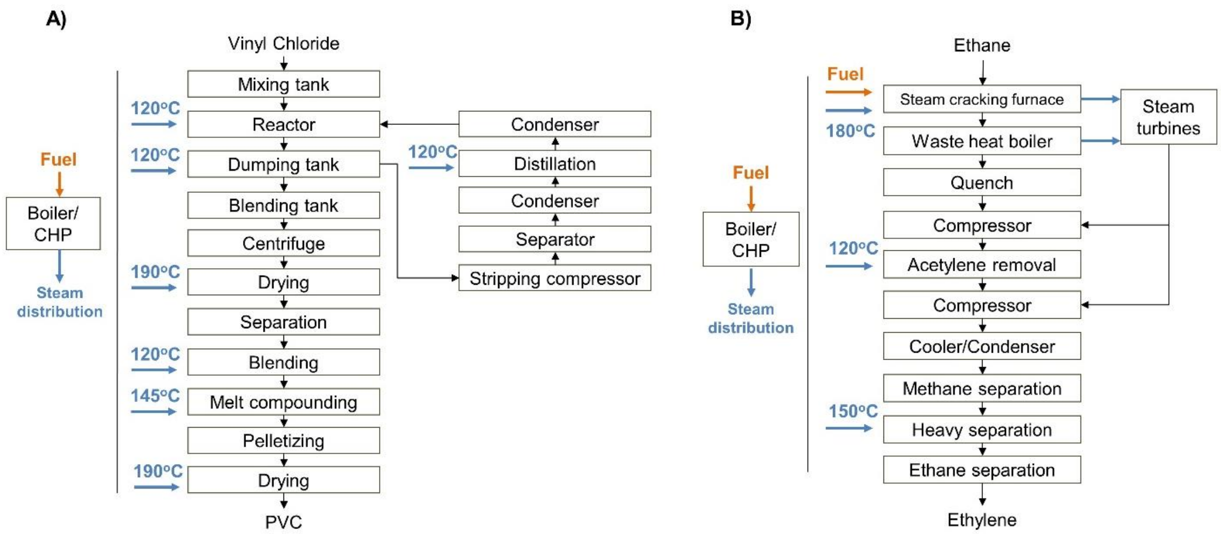


Figure 6-3. Unit process diagrams for A) PVC production and B) ethylene production. Adapted from [266].

For PVC production, the sum of thermal energy for processes using steam is assumed to be 2,066 MJ per one metric ton (t) of PVC produced based on process energy data from [49] (see Appendix D.3 for more detail). The energy inputs required for each process heat technology are calculated based on their efficiency or coefficient of performance (COP), as in the case of heat pumps (Table 6-2). With the heat pump, it is assumed that the heat source is waste heat from condensate streams ranging from 80-100°C, and the COP is 2, but in reality, COP varies based on the available waste heat streams, heat source and heat sink temperatures, and operation at individual facilities. For the case of hydrogen-blended boilers, hydrogen makes up 30% by volume of the fuel input, and the energy from hydrogen is calculated according to its energy content and density (see Appendix D.3).

Table 6-2. Efficiency and calculated energy inputs for process heat technologies. Efficiency data is from **[245], [251], [267]–[272]**.

	Process heat technology	System assumptions	Efficiency	Energy input (MJ/t)
Case 1: PVC	Conventional Boiler	NG	80%	2,583
	Electric Boiler	Grid	99%	2,087
	HTHP	Grid	1.5 (COP)	1,377

	H2-NG Boiler	30% H2	80%	2,290 (NG) 293 (H2)
	H2 Boiler	100% H2	80%	2,593
Case 2: Ethylene	Conventional Cracker	NG	60%	23,012
		30% RFG	60%	16,108 (NG) 6,904 (RFG)
	Electric Cracker	Grid, Louisiana (SERC)	90%	15,341
	H2 Cracker	100% H2	60%	23,012

For ethylene production, about 86% of the total process energy is for the steam ethane cracker. The assumed thermal energy for this process is 13,807 MJ/t of ethylene based on data from [273]. For the second conventional case, where RFG replaces a portion of the natural gas as fuel, 30% is assumed based on overall byproduct gas use in the industry and consultation with plant engineers.

While the energy inputs of fuel or electricity for process heat applications are important for determining facility costs and infrastructure needs, the primary energy associated with these energy inputs describe another level of efficiency that varies by technology and heat source. Compared to the conventional process heat technologies using natural gas, the primary energy of some electric technologies ranges from 1.5 to 2 times greater, but an exception is the heat pump compared to the conventional boiler, where primary energy is nearly the same. For process heat technologies using 100% green hydrogen, primary energy is around 4 times greater than the conventional natural gas technology, and around 1.5 times greater with 100% blue hydrogen technologies. Appendix D.3 provides assumptions and data for primary energy comparisons.

6.2.3 Environmental Impacts: GHG Emissions and Water Consumption Calculations

Two environmental impacts are quantified in this analysis – life cycle GHG emissions and water consumption. Upstream fuel cycle GHG emissions factors and water consumption factors of each energy source (natural gas, electricity, and hydrogen) are taken from the GREET 2022 model [274]. Combustion emissions of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) are accounted for in conventional technologies where natural gas is combusted, according to EPA emissions factors [275]. The 100-year global warming potential (GWP) values for CH_4 (29.8) and N_2O (273) are used to calculate CO_2-equivalent emissions for the non-CO_2 combustion emission [276]. Water consumption factors account for only consumption and not total water withdrawal. Furthermore, water factors do not include the amount of steam used in relevant process heat applications, which would be considered the same across technologies.

Table 6-3 shows the emissions and water use factors, which are multiplied by energy inputs in Table 6-2 to calculate the overall emissions and water footprints.

Table 6-3. GHG emissions and water consumption factors

	Process heat technology	System assumptions	GHG emissions (gCO_2e/MJ)	Water (gal/MJ)
Case 1: PVC	Conventional Boiler	NG	63.3	0.0033
	Electric Boiler	Grid, Louisiana (SERC)	139	0.204
		Grid, New Jersey (RFC)	132	0.106
		100% Decarbonized	9.7	0.062
	HTHP	Grid, Louisiana (SERC)	139	0.204
		Grid, New Jersey (RFC)	132	0.106
		100% Decarbonized	9.7	0.0622
	H2-NG Boiler	30% Green H2	57.8	0.0141
		30% Blue H2	61.0	0.0122
	H2 Boiler	100% Green H2	15.0	0.0987
		100% Blue H2	43.4	0.0818
Case 2: Ethylene	Conventional Cracker	NG	63.3	0.0033
		30% RFG	59.4	0.0023
	Electric Cracker	Grid, Louisiana (SERC)	139	0.204
		Grid, Texas (TRE)	123	0.280
		100% Decarbonized	9.7	0.0622
	H2 Cracker Furnace	100% Green H2	15.0	0.0987
		100% Blue H2	43.4	0.0818

For the 100% decarbonized grid, a grid mix of 35% solar, 25% wind, 25% natural gas with CCS, and 15% nuclear is assumed based on U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2023 data [277]. For process heat technologies using green hydrogen, it is assumed that hydrogen is produced from PEM electrolysis, and its emissions factor accounts for transmission, distribution, and compression. Lastly, for hydrogen-blended boilers, emissions factors and water factors are weighted by their portion of green hydrogen, blue hydrogen, and natural gas.

6.2.4 LCOH Calculation

The levelized cost of heat (LCOH) is a cost metric used to compare energy technologies that have different operating lifetimes and cost inputs. It is based on the levelized cost of energy (LCOE), which is commonly used in modeling costs of electricity generation. In a recent study, Gilbert et al. detailed an LCOH framework for industrial and building heating and applied it in several case studies for general heat processes in low temperature, high temperature and very high temperature applications [278]. LCOH has also been used in modeling district heating networks and solar thermal systems [279], [280]. For this analysis, LCOH is calculated based on the following equation:

$$LCOH = \frac{\sum(\frac{CAPEX_t + OPEX_t + EC_t + CC_t}{(1+r)^t})}{\sum(\frac{kWh_{th,t}}{(1+r)^t})} \qquad (6\text{-}1)$$

Where $CAPEX_t$ is the capital expenditures, $OPEX_t$ is the operating expenditures, EC_t is the energy cost, CC_t is the carbon cost, and $kWh_{th,t}$ is the thermal energy demand required by the process, all in year t. The sum of costs and energy demand are discounted by the factor, $(1 + r)^t$, in the year t with a discount rate, r, of 6.5%, which is within the range of similar analyses [114], [278]. This formula for LCOH is used in several studies [279], [281], [282], with some variations, such as the inclusion of system revenue or carbon price. In this analysis, LCOH includes a carbon cost that is equal to the U.S. social cost of carbon, set in 2021 at 51 USD. The timespan for the LCOH analysis is 20 years, which represents a common lifetime of equipment in chemicals industries [283].

Table 6-4 shows the assumed CAPEX and OPEX values for process heat technologies in each case study, and Table 6-5 shows the assumed energy costs for each heat source. Further descriptions of investment cost assumptions and yearly energy cost data are listed in Appendix D.4, and given that there is uncertainty with these estimated values, sensitivity analyses include changes in CAPEX and energy prices.

Table 6-4. CAPEX and OPEX data for process heat technologies [272], [284]–[292]

	Process heat technology	System assumptions	CAPEX (MMUSD)	OPEX (% of CAPEX)
Case 1: PVC	Conventional Boiler	NG	1.59	2.5
	Electric Boiler	Grid	1.13	1.0
	HTHP	Grid	3.24	3.0
	H2-NG Boiler	30% H2	1.59	2.5
	H2 Boiler	100% H2	1.91	2.5
Case 2: Ethylene	Conventional Cracker	NG	1,500	2.5
		30% RFG	1,500	2.5
	Electric Cracker	Grid	3,000	2
	H2 Cracker	100% H2	1,500	2.5

The costs of industrial natural gas and electricity by region for a 20-year period are based on industrial energy prices for the reference case in the EIA AEO 2023 [293]. The costs of green hydrogen assume PEM electrolysis in the Gulf and Northeast regions in 2022 [294], and future green hydrogen costs assume a reduction in the cost of hydrogen to 1.30 USD/kg by 2050 [295]. Since blue hydrogen is tied to natural gas prices, the costs of blue hydrogen are based on natural gas prices by state according to [296], and it is estimated that the cost of blue hydrogen remains the same over time [295].

Table 6-5. Costs of natural gas, electricity, green hydrogen, and blue hydrogen

Energy source	Energy cost (USD/MMBtu for NG, electricity, or USD/kgH2)		
	t =1 (2022)	t = 20 (2042)	State – Grid region
NG	6.83 7.34	4.41 5.17	Louisiana, Texas – West South Central New Jersey – Middle Atlantic
Electricity	20.76 28.65	19.82 24.73	Louisiana, Texas – West South Central New Jersey – Middle Atlantic
Green H2	2.79 4.57	1.30 1.30	Louisiana, Texas – West South Central New Jersey – Middle Atlantic

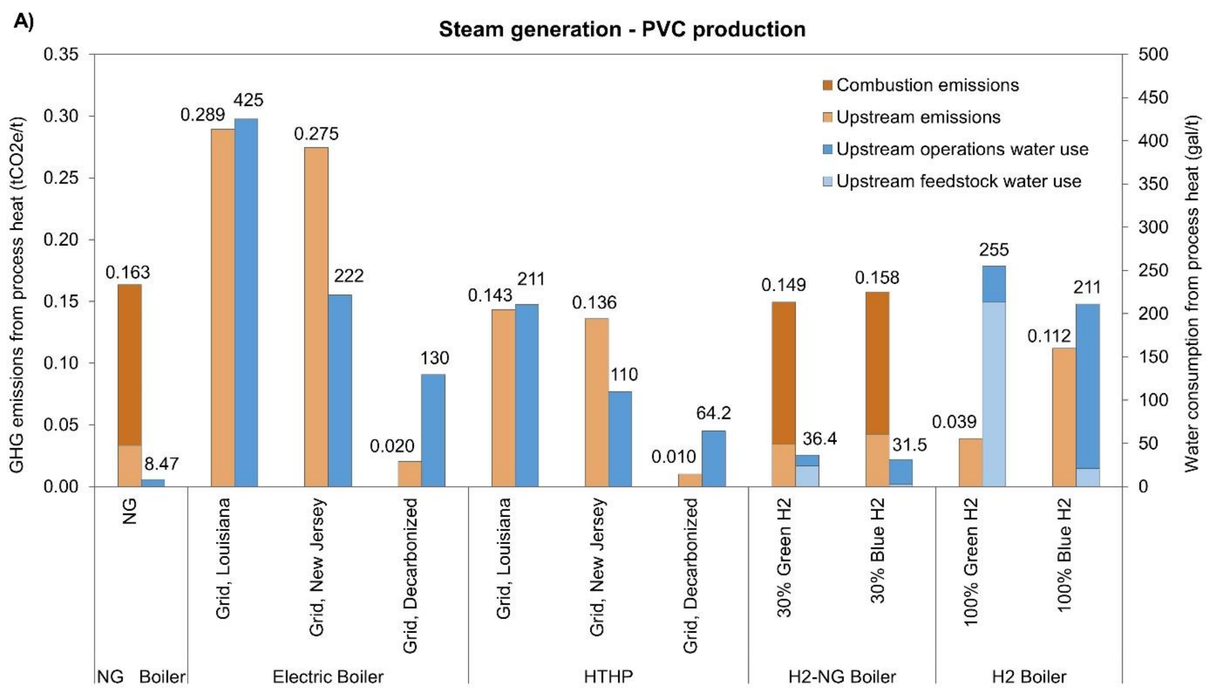
Blue H2	2.00 2.50	2.00 2.50	Louisiana, Texas – West South Central New Jersey – Middle Atlantic

The LCOH of process heat technologies is calculated for a typical U.S. PVC or ethylene facility based on production data from actual facilities in the U.S. DOE Industrial Assessment Centers database [297]. The PVC case assumes an annual production of 100,000 t of PVC, and the ethylene case assumes an annual production of 1,000,000 t of ethylene.

6.3 Results and Discussion

6.3.1 Environmental Impacts: GHG Emissions and Water Consumption

The life cycle GHG emissions and water consumption per metric ton of chemical produced are shown in Figure 6-4. The energy inputs, emissions factors, water use factors, and system assumptions are described in Table 6-1 - Table 6-3.



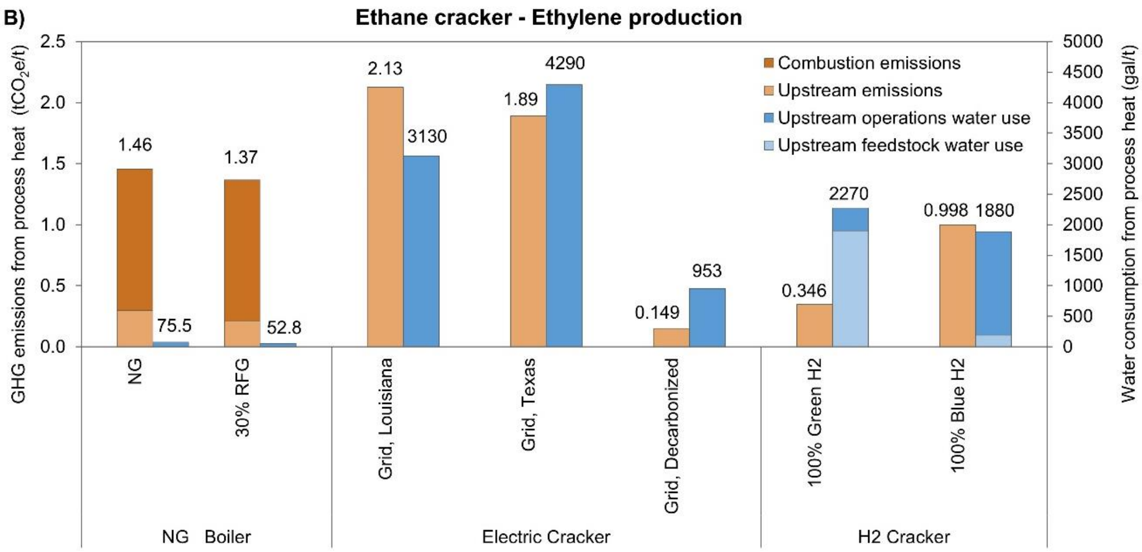


Figure 6-4. GHG emissions and water consumption of process heat technologies for A) steam generation in PVC production and B) the ethane cracker process in ethylene production. Upstream operations water use represents water consumed indirectly during the fuel production or energy generation process (e.g., natural gas extraction, electricity generation, hydrogen production using CCS); upstream feedstock water use represents water consumed as a feedstock in fuel production (e.g., electrolysis, steam methane reforming).

In the PVC case (Figure 6-4A), there are a few promising technology options that exhibit a reduction in GHG emissions in our chosen locations compared to the conventional heat system. These are an electric boiler with a decarbonized grid, a HTHP with a decarbonized grid, and a hydrogen boiler with green hydrogen. Whereas a conventional natural gas boiler emits 0.163 tCO_2e/t_{PVC} (16,300 tCO_2e for a 100,000 t/year facility), an electric boiler with a decarbonized grid has a nearly 90% emissions reduction with only 0.020 tCO_2e/t_{PVC} (2,000 tCO_2e for a 100,000 t/year facility). The existing amount of GHG emissions in the case of an electric boiler with a decarbonized grid arises from the defined makeup of the decarbonized grid, which includes 25% of electricity from natural gas with CCS (as described in Section 6.2.3). Although this portion of electricity includes CCS, the capture rate of CO_2 is 90%, based on assumptions in GREET, and these emissions account for the full fuel cycle of natural gas, including upstream methane leakage.

A HTHP with a decarbonized grid has the lowest emissions of all cases with only 0.010 tCO_2e/t_{PVC} and has a greater than 90% emissions reduction from the conventional system. Similar to the electric boiler case, these remaining emissions are also a result of the presence of natural gas in the decarbonized grid makeup but are overall lower due to the high electricity-to-heat efficiency of heat pumps. Even with the current electric grids, HTHPs could reduce emissions by 12% in the Southeast and 17% in the Mid-Atlantic. Lastly, a boiler fueled with 100% green hydrogen has an emissions reduction of over 75%, with emissions of 0.039 tCO_2e/t_{PVC}. In this case, fuel cycle emissions for hydrogen account for the grid electricity for compression and precooling of hydrogen and transmission and distribution.

While these three low carbon technologies lead to considerable emissions savings, each has a greater water consumption rate than the natural gas boiler in our chosen locations. Heat pumps and electric boilers with a decarbonized grid have life-cycle water consumption rates of 64 and 130 gal/t_{PVC}, respectively, which arises primarily from nuclear and natural gas with CCS in the grid makeup. In the case of a 100% green hydrogen boiler, the water consumption rate is even higher, 255 gal/t_{PVC}, due to the water required for electrolysis.

Other low carbon options, such as electric boilers under current electricity grids, hydrogen-blended boilers, and a 100% blue hydrogen boiler, lead to higher GHG emissions or minimal emissions reductions in our chosen locations. Electric boilers under the current grid in the Southeast lead to an emissions increase of 77% compared to conventional heating, and in the Mid-Atlantic, an increase of 69%. Although HTHPs have fewer emissions than electric boilers, HTHPs under the current grid in the Southeast lead to an increase in emissions by 17% and in the Mid-

Atlantic by 11%. The water use in both the electric boiler and HTHP systems under current grids are significantly higher than the conventional natural gas boiler. Water use is highest in the Louisiana cases, where electricity from coal plants, which has more than double the water consumption rate than natural gas plants, is nearly 30%, compared to 24% in the Mid-Atlantic region.

Hydrogen-blended boilers, whether green or blue hydrogen, have a GHG emissions impact (0.149 and 0.158 tCO_2e/t_{PVC}, respectively) that is nearly the same as the conventional natural gas boiler. This case examined a 30% volumetric blend of hydrogen with natural gas for boiler fuel, and given the low volumetric density of hydrogen, this results in only a 12% reduction in natural gas consumption. A 100% blue hydrogen boiler has a GHG emissions impact of 0.112 tCO_2e/t_{PVC}, which is a 30% reduction in emissions compared to a conventional boiler. The remaining emissions in this case primarily result from upstream natural gas processing, assuming a system methane leakage rate of 1%, and the steam methane reforming process of producing hydrogen given a CCS CO_2 capture rate of 96%.

In the case of ethylene production (Figure 6-4B), there are two technology options that show significant GHG emissions reductions in the Gulf region – an electric cracker with a decarbonized grid and a hydrogen-fueled cracker with green hydrogen. An electric cracker with a decarbonized grid has an emissions impact of 0.149 $tCO_2e/t_{ethylene}$, which compared to the conventional ethane cracking process using natural gas as the fuel (1.46 $tCO_2e/t_{ethylene}$) reduces emissions by a factor of nine. Although an electrified cracker is still in development and demonstration at scale phases, it represents the closest net-zero emissions option for the cracking process. A hydrogen-fueled cracker with green hydrogen has an emissions impact of 0.346 $tCO_2e/t_{ethylene}$, which is similarly a substantial reduction in emissions. However, its water use (2270 gal/t) from hydrogen production via electrolysis is more than double the electrified cracker (953 gal/t) in the Gulf region.

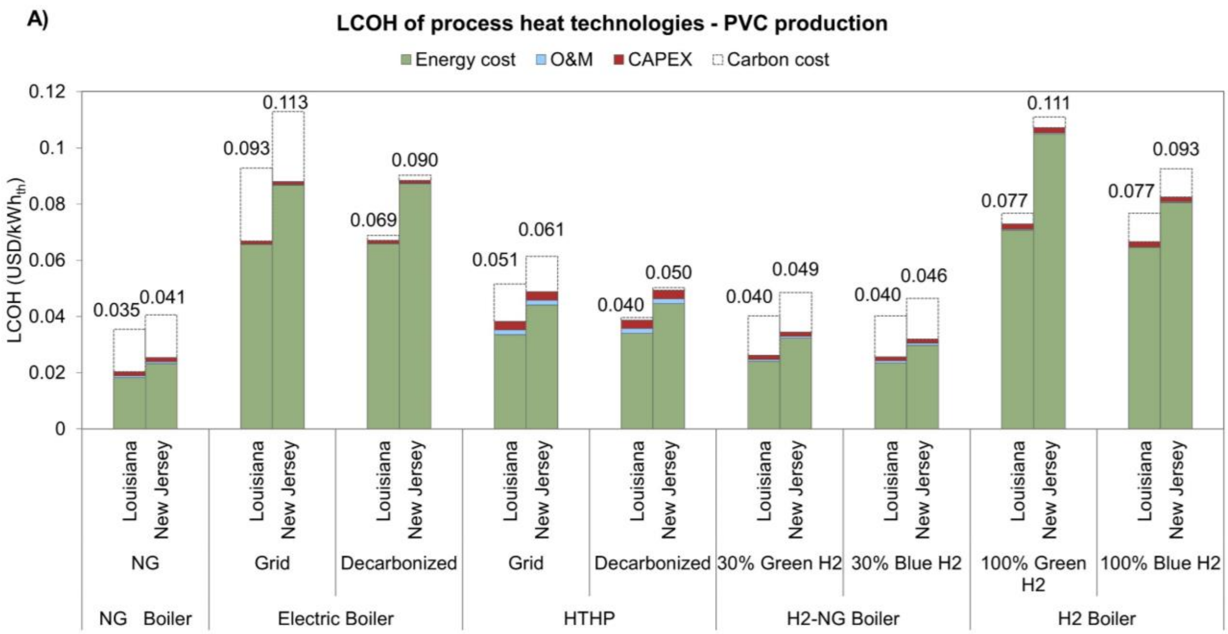
The second conventional cracking process using natural gas and refinery fuel gas as the fuel has a slightly reduced emissions impact (1.37 $tCO_2e/t_{ethylene}$) because some emissions from upstream natural gas processing and distribution are avoided with the use of onsite byproduct gases. Still, the emissions impact is substantial compared to the nearly net-zero alternatives, and switching to an electric cracker or hydrogen-fueled cracker would displace a significant amount of refinery fuel gas. In this case and without restrictions, facilities may flare refinery fuel gas, releasing CO_2 emissions and other air pollutants anyways, unless they develop alternate routes to utilize the byproduct gases, which typically consist of C2 to C4 hydrocarbons. However, if other processes in petrochemical facilities become electrified or transition to new production routes, the source for refinery fuel gas may be eliminated. For instance, if hydrogen production transitions from natural gas-fed steam methane reformers to electrolysis, the downstream byproduct gases that are currently combusted as fuel would no longer be produced.

Like the technology options for steam generation in PVC production, electrifying the ethane cracking process under current electric grids increases GHG emissions in the chosen location. An electric cracker operating under the same current grid mixes as Louisiana and Texas has an emissions impact of 2.13 and 1.89 $tCO_2e/t_{ethylene}$, respectively. Since electric crackers are not yet commercially available and may not be in this decade, it is unlikely that high emissions under this scenario come to realization, but it is important to note that electrified industrial processes must be paired with a sufficiently decarbonized grid in order to achieve reduction in emissions. Lastly, a hydrogen-fueled cracker with blue hydrogen has a 32% reduction in emissions compared to the conventional natural gas cracker. As in the case of a blue hydrogen boiler, emissions remain relatively high due to upstream natural gas processing and less than complete capture of CO_2 during the steam methane reforming process for hydrogen production.

6.3.2 LCOH

The LCOH represents the cost of heat over a technology's lifetime and is a useful metric for comparing the costs of different industrial heat technologies on a level basis. The LCOH of steam generation technologies for PVC production are shown in Figure 6-5A and ethane cracking technologies for ethylene production in Figure 6-5B.

For steam generation technologies in PVC production, the LCOH is dominated in each technology case by energy costs (i.e., the costs of natural gas, electricity, and hydrogen). Carbon costs also make up a large portion of LCOH in several cases. As discussed in Section 6.2.4, carbon costs are a component of LCOH, and although the U.S. does not have a national carbon market, the social cost of carbon (51 USD) is used in this analysis to represent the cost of damages from carbon emissions. The carbon costs are depicted in Figure 6-5 as dotted white boxes so that the LCOH of each technology case can be clearly observed with the absence of a carbon cost.



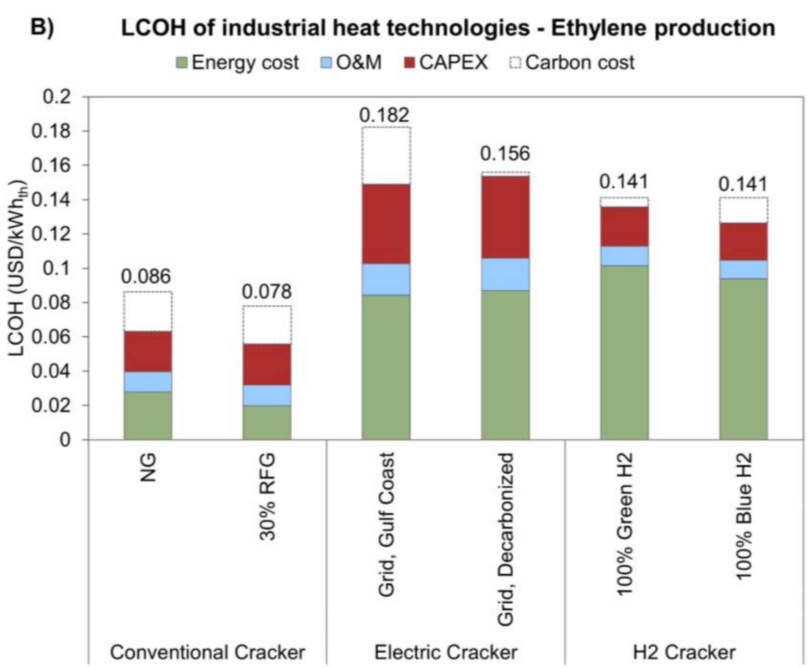


Figure 6-5. Levelized cost of heat of process heat technologies in A) steam generation for PVC production and B) the ethane cracker process in ethylene production. Technology systems are defined in Table 6-1.

Among the low carbon technology options, hydrogen-blended boilers and heat pumps have the lowest LCOH. Green and blue hydrogen-blended boilers have nearly the same LCOH, despite differences in the cost of hydrogen, because most of the fuel cost still comes from natural gas. In addition, the carbon cost is applied equally to that same portion of natural gas in the fuel mix. While LCOH for green and blue hydrogen-blended boilers ranges between 0.040 and 0.049 USD/kWh_{th} across the two states, which is within a 15% difference than the natural gas boiler, the environmental impact analysis shows that emissions savings are minimal and water use is significantly increased, and it is unlikely that this technology option offers much improvement over the conventional heating system in these regions.

Heat pumps are the next cheapest low carbon technology option for steam generation in PVC production. With a decarbonized grid, heat pumps are only about 15-22% more expensive than the natural gas boiler in the two states, whereas heat pumps under current grids are 46-49% more expensive due to the carbon costs associated with grid emissions. In both heat pump scenarios, CAPEX represents a larger fraction of the overall LCOH compared to other technology classes, but overall electricity costs are notably lower than with electric boilers due to the efficiency of heat pumps. Electric boilers under current grids are nearly three times as costly as natural gas boilers, and with a decarbonized grid, they are about twice as costly. In these cases, electricity costs make up the dominant portion of their LCOH, and despite the efficiency gains of electric boilers over combustion boilers, the price of electricity (20.59 USD/MMBtu in Louisiana in 2023) is about four times as much as the price of natural gas (5.62 USD/MMBtu). The sensitivity of certain parameters on LCOH, including energy prices, are explored in the next section.

Lastly, 100% hydrogen-fueled boilers are among the most expensive low carbon technology options. The LCOH for a green hydrogen boiler in Louisiana is the same as a blue hydrogen boiler, since the cost of carbon associated with emissions from natural gas use with blue hydrogen makes up for the higher cost of production with green hydrogen. In New Jersey, where the price of hydrogen is higher, the LCOH of both green and blue hydrogen boilers are greater than in Louisiana and more than double that of the conventional natural gas boiler. Paired with the environmental impacts that show modest reductions in GHG emissions, the high cost of blue hydrogen boilers makes it an unlikely option for decarbonized heat in this application.

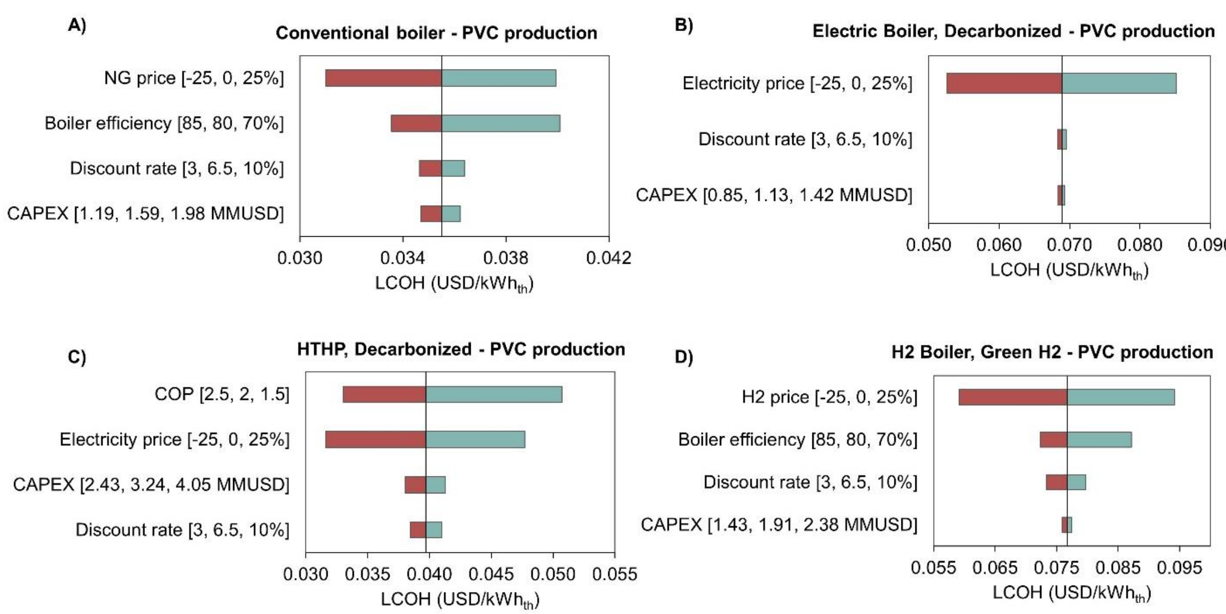
In the second case study of ethylene production, CAPEX accounts for a much larger portion of LCOH across all technologies in the Gulf region. However, there is uncertainty with the capital costs of emerging technologies which have yet to be developed at commercial scale. In this cost analysis the technologies are evaluated for the Gulf Coast region rather than specifically Louisiana and Texas as in the environmental analysis because the EIA projected energy costs are reported by region. Energy costs are still dominant in the low carbon technology scenarios. The electric cracker with a decarbonized grid has an LCOH with 0.156 USD/kWh_{th}, which is nearly double that of a conventional natural gas cracker, 0.086 USD/kWh_{th}. While CAPEX is currently expected to be high as an emerging technology, reductions in electricity prices or increases in natural gas prices would be necessary to make an electric cracker more competitive with conventional cracking operations.

The hydrogen crackers with both green and blue hydrogen have a slightly lower LCOH than the electric cracker and, in fact, have the same calculated LCOH, 0.141 USD/kWh_{th}. Although green hydrogen is more expensive than blue hydrogen, the cost of carbon associated with blue hydrogen raises its overall LCOH. These technologies are still significantly higher than both conventional routes. Finally, the second conventional cracker case that includes 30% RFG as fuel has a reduced LCOH (0.078 USD/kWh$_{th}$) due to the savings in purchased fuel and, to a lesser extent, a reduced carbon cost from the elimination of some upstream natural gas emissions.

Across all low carbon technologies in both case studies, low carbon technologies are more expensive than the conventional system, even with the inclusion of a carbon cost. Subsidies will likely be necessary to bridge the gap and ensure low carbon technology adoption. Based on this analysis, a carbon tax may not be enough since costs are primarily driven by energy costs and, in some cases, equipment costs. Policies could include production tax credits for clean energy, equipment rebates, and investments in research, development, and demonstration for emerging process heat technologies, such as electric crackers.

6.3.3 Sensitivity Analysis

A sensitivity analysis was conducted to determine how changes in key parameters affect the LCOH of the industrial heat technologies. Figure 6-6 shows the changes in LCOH from baseline values for the conventional case and certain promising low carbon technology cases.



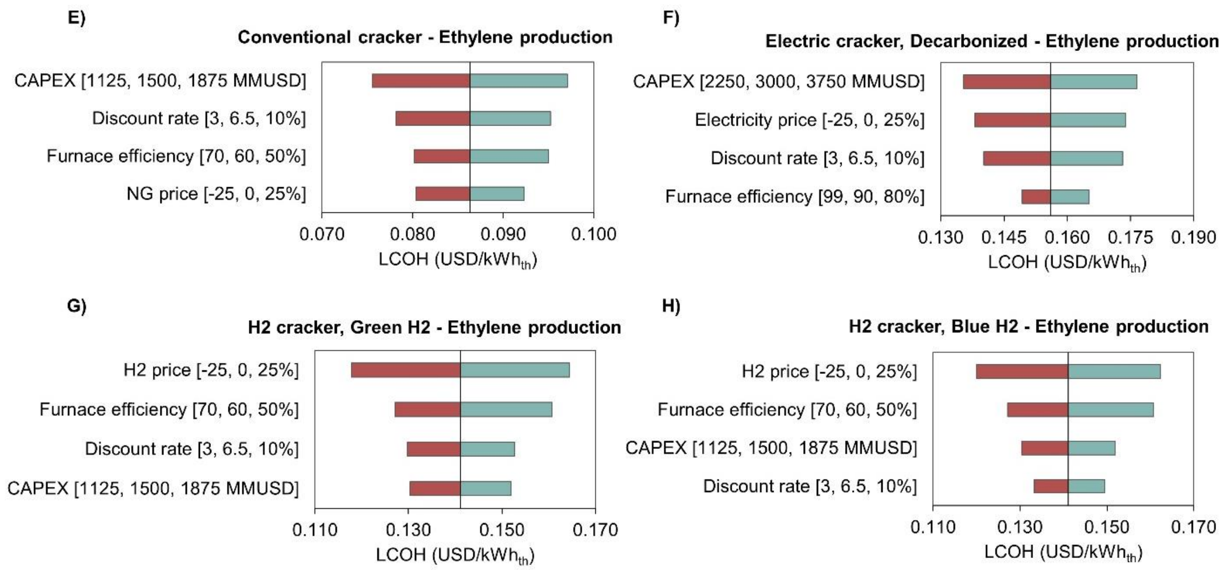


Figure 6-6. Sensitivity analysis of A-D) steam generation technologies for PVC production and E-H) ethane crackers for ethylene production, for a facility in Louisiana. Parameters that affect LCOH are listed on the y-axis. In brackets are the changed parameter that reduces LCOH (left), the baseline parameter (center), and the changed parameter that increases LCOH (right).

The price of natural gas has the largest impact on the LCOH of a conventional boiler in PVC production (Figure 6-6A) – a 25% rise in the natural gas price increases the LCOH by 13%. Boiler efficiency, which directly affects natural gas consumption, has the next largest impact. For an electric boiler with a decarbonized grid, the price of electricity dominates the impact on LCOH (+/- 18% for a +/-25% change in electricity price). While the CAPEX of electric boilers is less than combustion boilers and electricity-to-heat efficiency is already near 100%, this result demonstrates the significant barrier of high electricity prices, preventing this technology from being more cost-competitive with conventional boilers.

Alternatively, heat pumps with high COPs could be less expensive than conventional boilers. An increase in heat pump COP from 2 to 2.5 reduces the LCOH to 0.33 USD/kWh$_{th}$, which is less than the baseline conventional boiler. Additionally, a drop in electricity prices reduces LCOH to 0.32 USD/kWh$_{th}$ (-20% for a -25% change in electricity price), also making heat pumps less expensive. Lastly, the price of hydrogen has the largest impact on the 100% green hydrogen boiler, which is among the highest cost low carbon technologies. Even with a 25% drop in the price of green hydrogen, LCOH only reduces by 23% to 0.059 USD/kWh$_{th}$, which remains out of range from the conventional boiler. However, tax credits for green hydrogen could effectively remove the burden of the fuel costs. Still, green hydrogen boilers may have limited feasibility for this application given rising demand for hydrogen in other industries and other available heating technologies that are already economically favorable.

In ethylene production, a change in the CAPEX of crackers has the greatest effect on LCOH, but LCOH is nearly as sensitive to changes in other factors. For the conventional cracker, natural gas prices have a smaller effect on LCOH than CAPEX. Similarly, the electric cracker is less sensitive to electricity prices since CAPEX is estimated to be high, but electricity prices do have the second largest impact on LCOH. For both green and blue hydrogen crackers, hydrogen prices have the largest impact. If green hydrogen prices were to decrease by more than 25%, which may be possible with hydrogen production tax credits in the Inflation Reduction Act, a green hydrogen cracker could be economically competitive with a conventional cracker.

6.3.4 Cost of Abatement

The marginal cost of abatement represents the dollar amount change associated with an activity that reduces emissions. In this analysis, the cost of abatement is another measure of economic comparison for the different low carbon process heat technologies. Figure 7 shows the cost of abatement curve for the low carbon steam ethane cracker options in ethylene production (see Appendix D.6 for the PVC case). The cost of abatement is plotted against the abatement potential, which is the total amount of emissions reductions that would result from adopting the technology in a typical ethylene facility in the Gulf region.

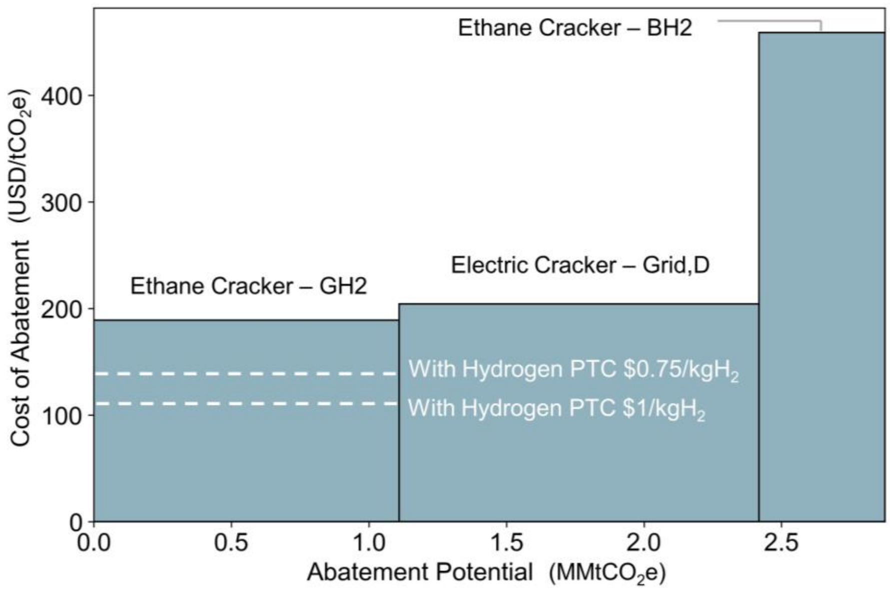


Figure 6-7. Cost of abatement curve for low carbon steam ethane cracker options in ethylene production. GH2 is green hydrogen; Grid, D is decarbonized grid, BH2 is blue hydrogen; PTC is production tax credit.

Typically, some emissions-reducing activities or technologies may have a negative cost of abatement, indicating cost savings associated with removing a ton of carbon dioxide equivalent. However, in this case study, only three of the evaluated low carbon technology options have potential emissions reductions, and none has negative costs of abatement. The green hydrogen ethane cracker and electric cracker with a decarbonized grid represent the lowest cost options with sizable abatement potential compared to the blue hydrogen ethane cracker. When considering hydrogen production tax credits, whether 0.75 USD/kg or 1 USD/kg of hydrogen, which are amounts set in Inflation Reduction Act policy and relevant in this case based on the life cycle emissions of the green hydrogen production, the cost of abatement could be reduced to 130 USD/tCO$_2$e or 109 USD/tCO$_2$e, respectively. Still, these high costs imply barriers still exist for pursuing these technology options and that additional policy incentives are needed to make these low carbon options cost-competitive.

6.4 Conclusion

In summary, this work investigates electrification and hydrogen technologies as industrial process heat options and provides a framework for technical, environmental, and economic analysis for low carbon process heat decarbonization in other industries. With a facility-level perspective for several locations in the United States, this research quantifies the GHG emissions, water use, and LCOH of electric boilers, industrial heat pumps, and hydrogen boilers in PVC production and of electric steam ethane crackers and hydrogen-fueled steam ethane crackers in ethylene production. Results show that emissions reductions could be possible with electrification technologies only with a sufficiently decarbonized electric grid and with 100% green hydrogen combustion, but water use increases in each low carbon case compared to conventional natural gas combustion in the selected locations. Considering the cost impacts, results indicate that for each of these low carbon technologies their LCOH is significantly higher, ranging roughly from 50-100% more than the conventional technology, even with the inclusion of a carbon cost, and that LCOH in most cases is dominated by energy prices.

These findings suggest that policies could focus on subsidies, such as production tax credits and in some industries equipment rebates and investment tax credits, rather than carbon pricing. The policies in the IIJA and IRA have immediate implications for the technologies evaluated in this study and for industrial process heat decarbonization in general. In particular, the regional hydrogen hubs put forward in the IIJA will likely influence the development of hydrogen infrastructure in some regions, making it a more accessible fuel option for some manufacturing facilities. Similarly, the 45V hydrogen production tax credit in the IRA, which offers varying levels of credits awarded to clean hydrogen production, could make the green hydrogen combustion technologies more cost competitive [298]. Additionally, the IRA extends renewable electricity production tax credits, which are necessary for power sector decarbonization and for electric heating technologies to achieve emissions reductions.

7. Conclusions and Future Research

7.1 Summary of Work

The main theme of this dissertation is investigating assessment methods of emerging low carbon technologies and industrial sector data to enable the decarbonization of industrial process heating. Through several research projects, an energy systems analysis framework that consists of classifying industrial facility- and unit-level data, characterizing low carbon and conventional process heat technologies, modeling technology energy use, and assessing emissions and cost impacts is developed. The research addresses many key challenges in industrial decarbonization, including the lack of bottom-up process-level modeling of energy technologies and data scarcity with respect to industrial facility and unit information. The outputs of this research serve as case studies of several low carbon process heat options across the U.S. manufacturing sector and identify important areas for expanded research and policy implementation.

Chapter 2 reviews solar industrial process heating (SIPH) technologies and installations, both globally and in the US, modeling approaches for evaluating SIPH technical and economic potential, and known barriers to SIPH adoption, as part of a research collaboration with NREL. The continuation of this research is further described in Chapter 3, which summarizes the modeling of SIPH technical and economic potential. Both solar thermal technologies and electric heat technologies paired with solar photovoltaic (PV) electricity are evaluated by modeling solar resource availability and solar heat supply alongside the county level industrial process heat demand with temporal and spatial detail. The intermittent nature of solar heat is the main barrier for industrial operations that run continuously, highlighting the importance of thermal energy storage.

Extending the analysis of one electrification technology from the SIPH study, research in Chapter 4 analyses the potential of electric boilers with more detail. A dataset of conventional industrial boilers is developed and made public, providing an up-to-date characterization of the stock of boilers in the US. The potential for electrifying industrial boilers is evaluated based on changes in primary energy use and life cycle emissions under several electric grid scenarios. Ultimately, boiler electrification requires a decarbonized electric grid to achieve emissions savings collectively across the country. Several aspects of the data analysis used to characterize industrial boilers are further studied in research covered in Chapter 5. In this chapter, sources of industrial facility- and unit-level data are explored, their limitations are documented, and additional analyses identify new ways to capture data on unit types, material throughput, and unit energy use.

Lastly, Chapter 6 describes a framework for evaluating low carbon process heat options and applies it in two case studies in chemicals manufacturing, where electrification and hydrogen technologies are compared to conventional process heating. Several electrification technologies with a sufficiently decarbonized grid and green hydrogen combustion could achieve reductions in emissions, but lifetime costs remain much higher than conventional heating due to energy prices and, in some cases, capital expenditures, which indicates the need for responsible policies targeting energy production and high-capital equipment.

7.2 Recommendations for Future Research

An important area for future research spanning all of the work discussed in this thesis is analyzing facility-level effects of low carbon technology adoption. There is a widespread need in industrial decarbonization research for more detailed analysis that captures the effects of electrification or fuel switching, such as with solar heating or clean hydrogen, both within the fence line of manufacturing facilities and outside it. For instance, many facilities have highly integrated heat supply networks, making use of waste heat with heat exchangers or of byproducts for fuel combustion. It would be useful to better capture the economic costs of replacing these systems and the physical equipment needed to integrate low carbon technologies, as well as the potential non-energy cost benefits. Also, future analysis should account for factors outside the fence line, such as whether nearby infrastructure (e.g., electricity transmission, hydrogen distribution network) is in place and how new electricity load demands balance with what the grid can supply, especially at hourly timescales. With electrification as a direct and indirect (via solar PV or green hydrogen) decarbonization lever for the industrial sector, there is a great need to combine industrial energy modeling with electric grid modeling.

Furthermore, future research should continue to identify optimal conditions for low carbon technology adoption through analysis of case studies. Specifically, analyses could look at successful cases considering some of the internal equipment and external infrastructure factors mentioned above or state and local policies that enable low carbon technologies to be economically competitive with conventional fossil fuel technologies.

Lastly, despite efforts to make industrial sector data more open and public, there are still areas in which research could provide more detailed information from existing data sources and the creation of new datasets. For example, the NEI is a national emissions database with abundant unit-level data that could offer insights on fuel use and equipment age over time. Statistical techniques could further extrapolate data on units not accounted for in the database. State and local air permits are another source of industrial unit-level data where the intersection of advanced data science techniques like machine learning could be applied to extract unit vintage, capacity, and expected emissions amounts. Improved quantity and quality of process unit data would lead to more accurate assessments of low carbon technologies in industry.

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Appendix A. Supporting Information for Chapter 3

A.1 Methods for Estimating County-level Process Heat Demand

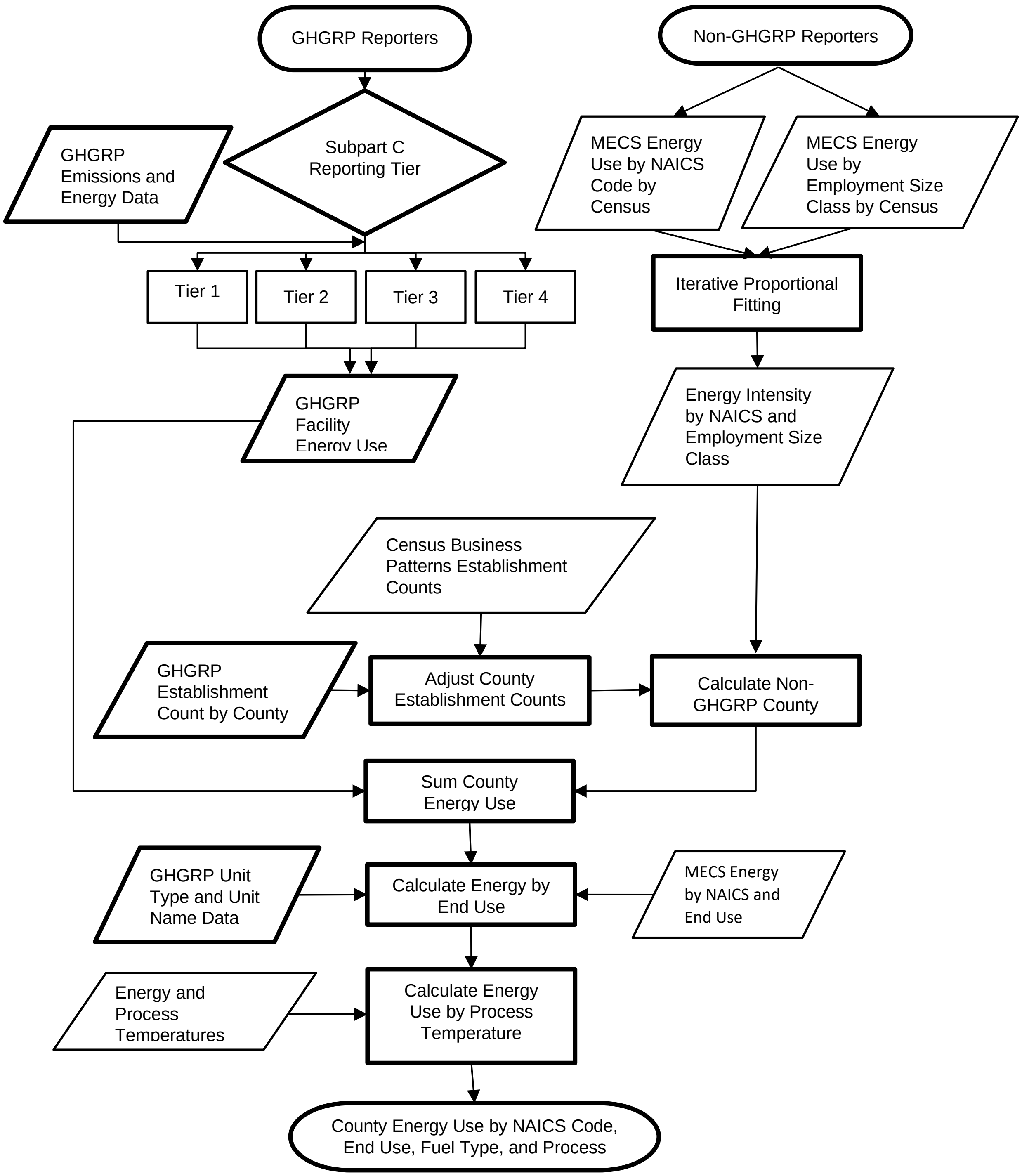

Figure A-0-1. General process for estimating 2014 county-level industrial process heat demand

Figure A-0-1 above is a schematic for the process of estimating county-level process heat demand. The full methodology descriptions are provided in [113].

A.2 Land Area Exclusion Criteria in Solar Generation Modeling

The following table describes the criteria definitions for excluding certain areas of land in this SIPH potential analysis.

Table A-0-1. All exclusion criteria used for land availability analysis

Data Set	Criteria
Slope	slopes greater than 3% (for parabolic trough) or 5% (for PV or FPC)
Urban Areas	suburban areas
	urban areas
Land Cover	open water
	woody wetlands
	emergent herbaceous wetlands
	deciduous forest
	evergreen forest
	mixed forest
BLM ACEC	Bureau of Land Management areas of critical environmental concern
Federal Lands	national battlefield
	national conservation area
	national fish hatchery
	national monument
	national park
	national recreation area
	national scenic area
	national wilderness area
	national wildlife refuge
	wild and scenic river
	wildlife management area
	national forest
	national grassland
	US Air Force Guard land
	US Air Force land
	US Army land

Data Set	Criteria
	US Army Guard land US Coast Guard land US Marine Corps land US Navy land
Airports	Airports
Protected Areas Database of the United States	Status 1: an area having permanent protection from conversion of natural land cover and a mandated management plan in operation to maintain a natural state within which disturbance events (of natural type, frequency, intensity, and legacy) are allowed to proceed without interference or are mimicked through management Status 2: an area having permanent protection from conversion of natural land cover and a mandated management plan in operation to maintain a primarily natural state, but which may receive uses or management practices that degrade the quality of existing natural communities, including suppression of natural disturbance.
National Conservation Easement Database	Status 1: managed for biodiversity: disturbance events proceed or are mimicked Status 2: managed for biodiversity: disturbance events suppressed

A.3 Screening Scores for Electric Heating Technologies

To select which electric heating technologies to include in the scope of this analysis, a range of electrotechnologies was reviewed and evaluated based on a defined set of criteria. Table A-0-2 shows the summary of this screening exercise.

Table A-0-2. Summary of screening of electrotechnologies

Electrotechnologies	Technical Potential for Conventional Fuel Replacement[a]	Weighted Score[b] of Technical Potential	Data Availability[c]	Weighted Score of Modeling Confidence	Market Growth Outlook[d]	Weighted Score of Market Growth Outlook	Overall Score
Electric boiler	3	6	3	3	3	3	**12**
Ambient heat pump	3	6	3	3	2	2	**11**
Resistance heating and melting	3	6	3	3	2	2	**11**
Waste recovery heat pumps	2	4	3	3	3	3	**10**
Induction heating and melting	2	4	3	3	3	3	**10**
Infrared processing	2	4	3	3	3	3	**10**
Microwave heating and drying	2	4	3	3	3	3	**10**
Radio-frequency heating and drying	2	4	3	3	3	3	**10**
Direct arc melting	2	2	3	3	3	3	**10**
UV (ultraviolet) curing	1	2	3	3	3	3	**8**
Plasma processing	1	2	3	3	2	2	**7**
Vacuum melting	1	2	2	2	3	3	**7**
Laser processing	1	2	3	3	2	2	**7**
Ladle refining	1	2	1	1	1	1	**4**

[a] Score rubric for technical potential for conventional fuel replacement: potential >= 500 TBtu/year, score = 3; 100 TBtu/year <= potential < 500 TBtu/year, score = 2; potential < 100 TBtu/year, score = 1

[b]Weighting factors: technical potential for conventional fuel replacement (2), data availability (1), and market growth rate (1)

[c]Score rubric for modeling confidence: case studies with sufficient technical information or mature engineering models, score = 3; case studies with limited technical information or preliminary models, score = 2; few/no technical case studies and no models, score =1

[d]Score rubric for market growth outlook: 5-year growth rate (from 2015 to 2020) >= 10%, score =3, 0% <= 5-year growth rate <10%, score =2; 5-year growth rate<0%, score =1 [299]

A.4 Matching SIPH Technologies to Industrial Process Heat Demand

Table A-0-3 summarizes the characteristics of SIPH technologies and the portion of IPH demand for which they are applicable as defined in this analysis.

Table A-0-3. Parameters defining feasible process heat demand for SIPH systems

Solar Technology	Characteristics of Solar Heat Supplied	Applicable IPH End Use	IPH Demand Limited to:
Flat plate collector	Temperature, <90°C Uses: hot water, boiler feedwater preheating	Conventional boiler, CHP	Hot water
Parabolic trough collector	Temperature, <400°C Uses: steam, direct processing heat	Conventional boiler, CHP, PH	Process temp <340°C
Linear Fresnel w/ direct steam generation (DSG)	Temperature, <250–400°C Uses: steam	Conventional boiler, CHP	Process temp <212°C
PV + electric boiler	Uses: steam, hot water	Conventional boiler	Capacity <50 MW
PV + resistance	Temperature, <1,800°C Uses: dryers, furnaces, ovens, kilns	Conventional boiler, CHP, PH	Relevant unit processes and industries
PV + heat pump (waste heat recovery and ambient)	Temperature, <160°C Uses: steam, hot water, hot air	Conventional Boiler, CHP, PH	Relevant unit processes and industries

A.5 Methods for Calculating Process Heat Demand

Figure A-0-2 shows the methods flowchart for determining the portion of process-level heat demand feasible for each solar technology.

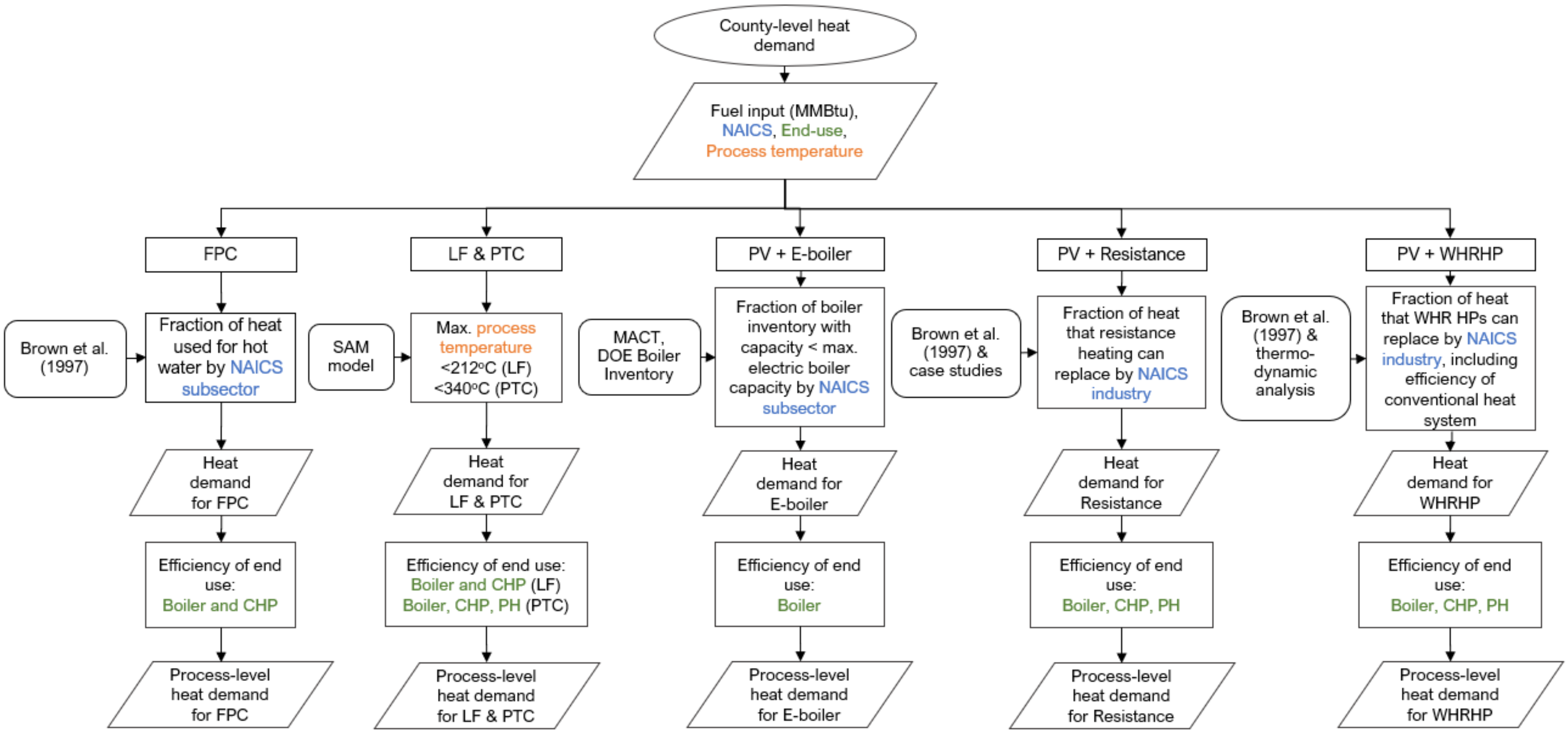

Figure A-0-2. Flowchart for calculating process energy for each SIPH system. Sources listed in rounded squares include **[266]**, **[150]**, **[161]**

Figure A-0-3 provides further detail on the end-use efficiency calculation. For IPH fuel use by conventional boilers, the efficiency depends on fuel type. For CHP units, efficiency depends on the prime-mover type, which is determined for each county by analyzing the DOE CHP installation database.

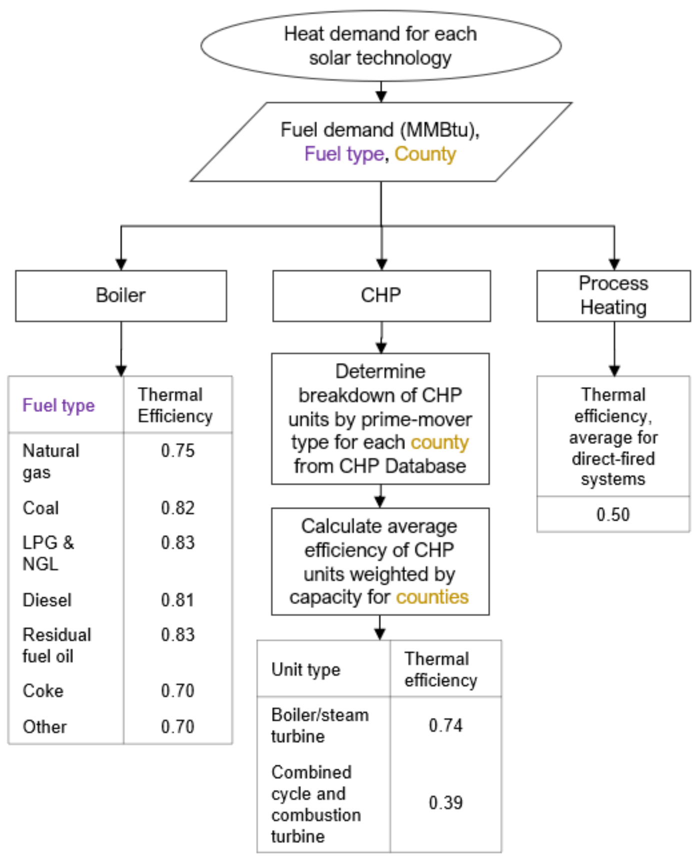

Figure A-0-3. Flowchart for determining efficiencies of IPH end-uses

Appendix B. Supporting Information for Chapter 4

B.1 Data Integration of GHGRP, MACT, and NEI Databases and Development of the Industrial Boiler Dataset

Data downloaded from the GHGRP for general stationary fuel combustion sources contain boiler units in both the power and industrial sectors, so boiler units within the manufacturing sector are identified by North American Industry Classification System (NAICS) codes 31-33. In this population of GHGRP data, we identify boilers with unit types or unit names classified as "boiler" and, in some cases, "other combustion source" (OCS). If the unit type is OCS and the unit name does not indicate whether the entry is a boiler unit, the OCS units are compared later with boiler data in the MACT and NEI databases and removed if no match is found.

To obtain the installed capacities of boilers, the data for general stationary fuel combustion sources are processed using the following steps in Python.

1) Merge data from different Excel files downloaded from the GHGRP by facility ID, reporting year, and unit name.
2) Select all unit types which contain "boiler"
3) Select all unit names which contain "boiler" or related text
4) When the unit type is "OCS", select all unit processes since some reporting facilities may classify boilers as OCS
5) Drop the duplicated entries in step (1) to (4)

The data obtained from the MACT database are matched with the data obtained from the GHGRP by county Federal Information Processing Standards (FIPS) codes, facility name, and boiler capacity. The two databases, GHGRP and MACT, are merged by using facility name and county FIPS, and the duplicated information is deleted from the merged dataset. In addition, the entries without installed capacity information (<50 entries) are removed from the dataset since the installed capacity is essential information for characterizing the equipment stock in this study. It should be noted that some of the boiler data are recorded in multiple years and only the data from the most recent year are retrieved. Finally, data from the NEI, also filtered by manufacturing NAICS codes, “unit type” as boiler, or “unit name” containing the word “boiler” or related text, are combined and cross-checked with the units from the GHGRP and MACT.

Figure B-0-1 illustrates the full process of collecting, matching, and data between the Environmental Protection Agency’s (EPA) Greenhouse Gas Reporting Program (GHGRP) [160], Maximum Achievable Control Technology (MACT) [161], and National Emissions Inventory (NEI) [162] databases. The diamond and rectangle boxes in black represent the key decision steps and actions, respectively, for addressing both duplication and discrepancies among the three databases with further descriptions provided below. Figure B-0-2shows the full process of estimating the count of non-reported boilers using capacity and operating hours assumptions and estimated county boiler fuel use from the NREL thermal energy dataset [145].

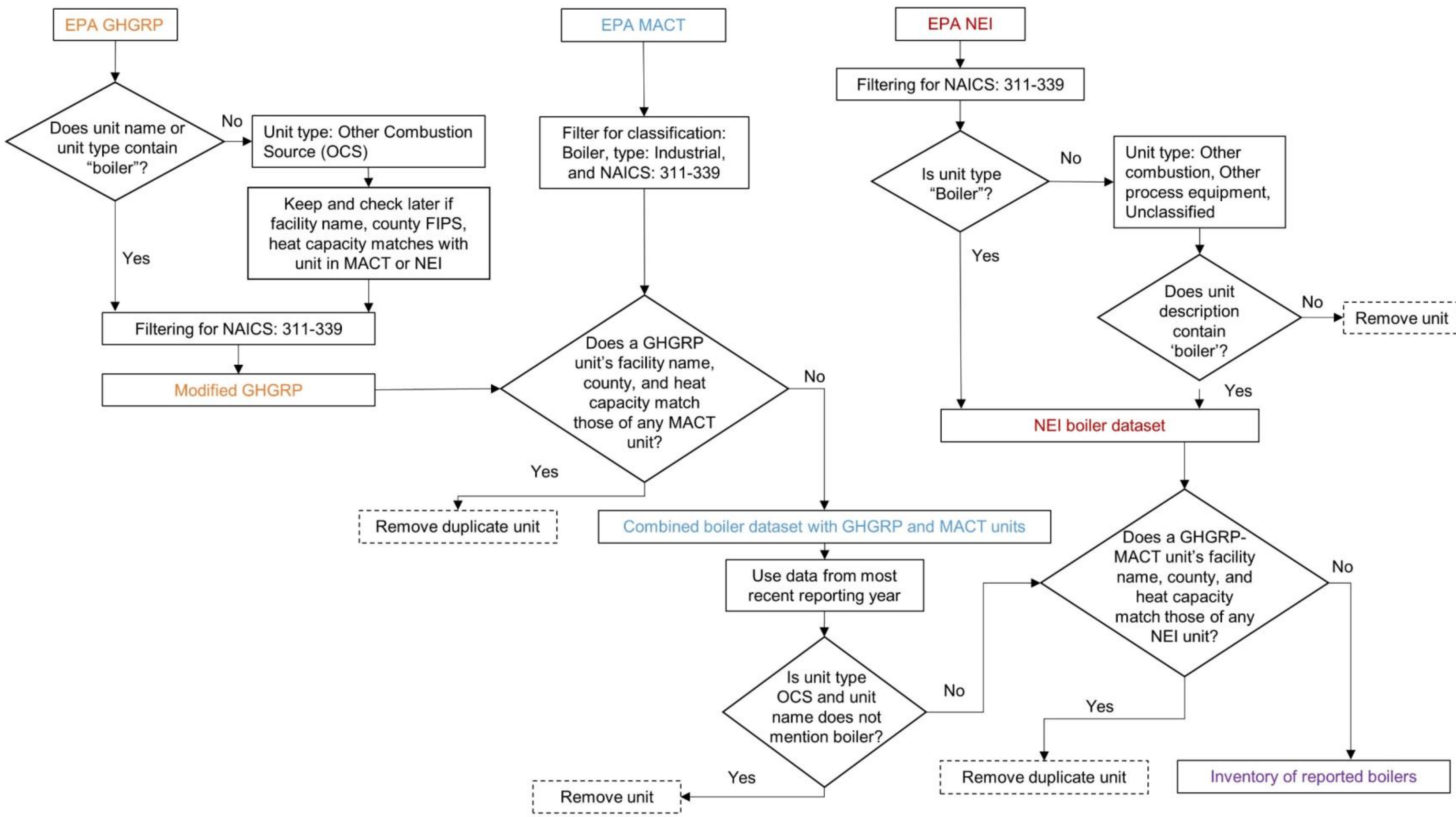

Figure B-0-1. Flow diagram of integrating data from EPA GHGRP, MACT, and NEI to create inventory of reported boilers

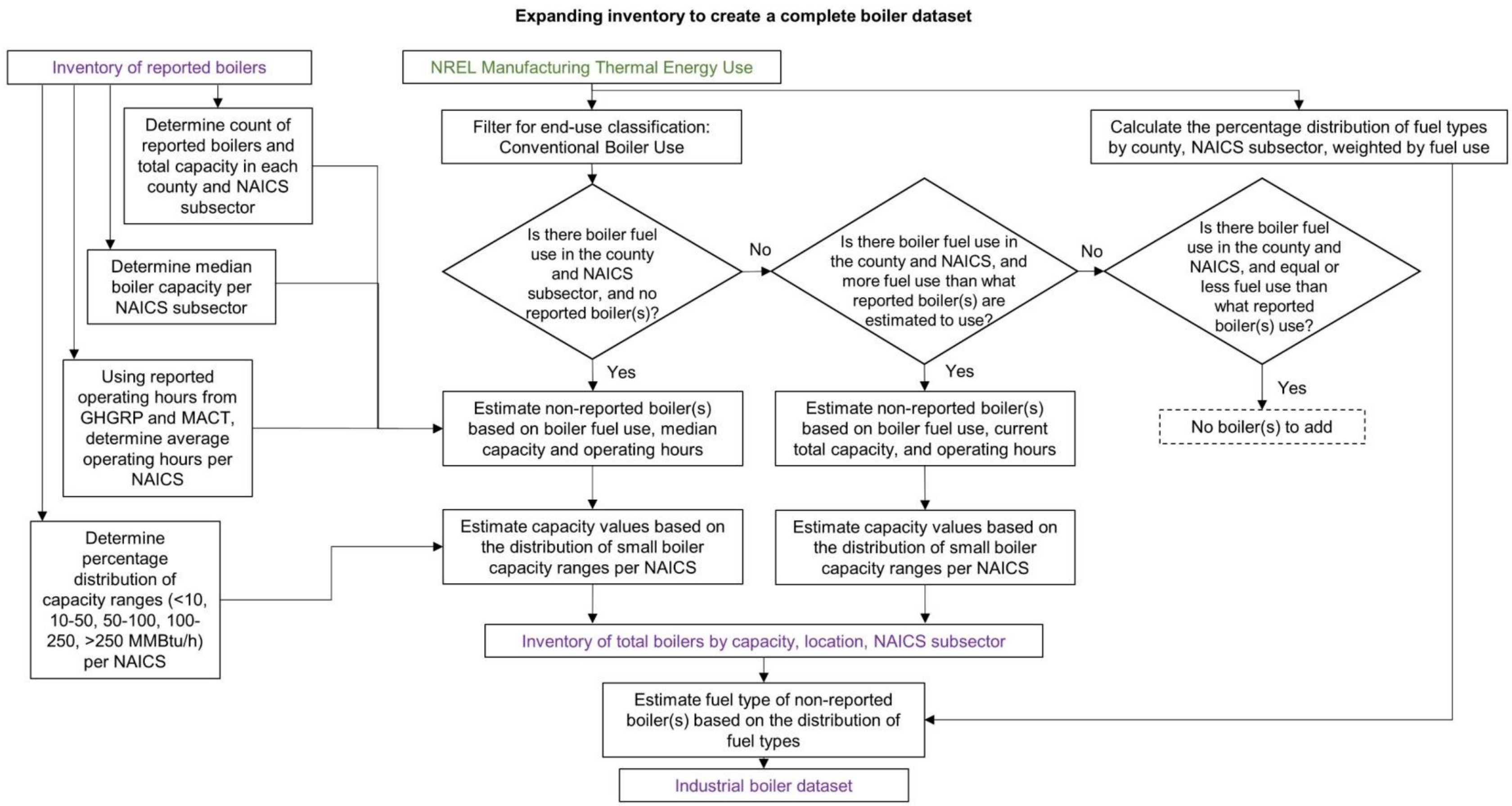

Figure B-0-2. Flow diagram of estimating the count of non-reported boilers and their characteristics to assemble the final industrial boiler dataset

Sources of uncertainty in industrial boiler dataset

Table 4-1 provides an overview of the characteristics of our three main sources of data: the EPA's GHGRP, MACT, and NEI. Since each EPA database has different reporting requirements, there are different levels of uncertainty present in the data collected for our dataset. Despite the various reporting requirements in these databases, in each case the data from facilities that were compiled by the EPA can contain errors or be misinterpreted. In our data cleaning and filtering steps, we removed line items that did not display clear values for boiler capacity, industrial subsector, and unit type. Furthermore, since these emissions databases are not standardized to one format with the same category of variables, the fuel type information for boiler units was often recorded in different ways (see Section B.3), so the various fuels listed or described in text were sorted into broad fuel type categories for standardization. Finally, due to gaps in reporting from facilities, the estimation of non-reported boilers presents a source of uncertainty. Besides the count of non-reported boilers which is estimated based on the methods described in Chapter 4, the determination of boiler capacity for estimated units represents an area of uncertainty, and capacity values for estimated units should be considered within a boiler capacity range (<10 MMBtu/hr and 10-50 MMBtu/hr) rather than their listed capacity value in the dataset.

B.2 Approximation of Total Count of Boilers in Industrial Boiler Dataset and Comparison to U.S. Industrial Boiler Characterization from 2005

The Energy and Environmental Analysis (EEA) report [150] characterizing industrial boilers from 2005 estimated the total number of industrial boilers to be 43,015. It also reports the total number of manufacturing establishments as 363,000. To approximate an expected total count of boilers for our study in 2021, the number of manufacturing establishments as reported by the EEA report are compared to the manufacturing establishments as reported by the U.S. Census County

Business Patterns (CBP) in 2019 (the latest data) [176]. The CBP data reports 287,626 manufacturing establishments in 2019 and, based on the percent change between the total number of establishments over the years, and assuming a constant ratio of boilers to establishments, the approximated count of industrial boilers is roughly 34,000. This brief analysis is used to assess the reliability of our estimated count of boilers calculated from the county-level fuel use data.

Furthermore, the results of our industrial boiler dataset are compared with the results from [150]. We note that the 2005 EEA report has results of the number of industrial boilers and total installed capacities for only five subsectors, shown in Figure B-0-3 and Figure B-0-4, so we group our results in equivalent categories for comparison. Additionally, the primary data sources for its boiler inventory are a 1996 report also produced by EEA, which relied largely on DOE and EPA reports from 1977, the IHS Energy Major Industrial Plant Database (MIPD), which tracked energy consumption at 15,000 facilities (out of 363,000 total), and 1998 Manufacturing Energy Consumption Survey (MECS). Compared to the 2005 EEA report, the boiler characterization from our industrial boiler dataset shows more boilers in subsectors other than the major steam-consuming subsectors but a similar profile in terms of total installed capacity.

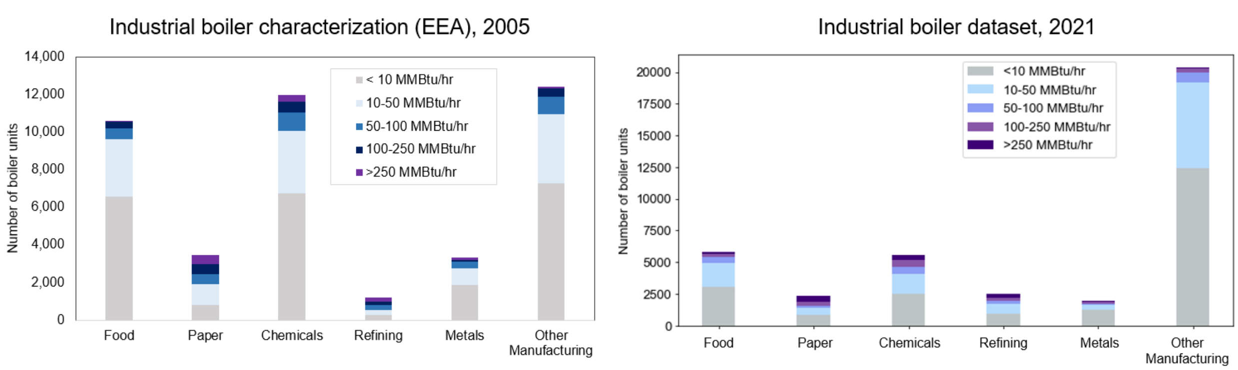

Figure B-0-3. Comparison of the estimated number of boilers from the industrial boiler characterization in 2005 from **[150]** and our industrial boiler dataset

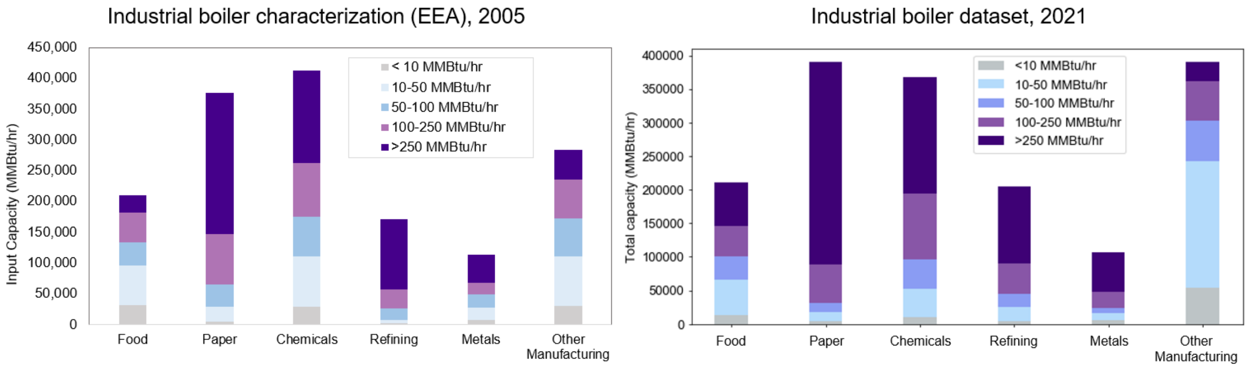

Figure B-0-4. Comparison of the estimated total installed boiler capacity from the industrial boiler characterization in 2005 from **[150]** and our industrial boiler dataset

B.3 Fuel Type Category Descriptions

This section lists the fuel type categories in our industrial boiler dataset and in the NREL thermal energy use in manufacturing dataset [145]. The fuel type categories defined in our industrial boiler dataset are based on the reported unit fuel types in the GHGRP, MACT, and NEI databases, which each have various ways of reporting boiler fuel type. The level of specificity for boiler fuel types varies in each database, so fuel type information was grouped according to the broadest possible categories listed Table B-0-1 below. The fuel types listed in the NREL thermal energy use dataset are the same fuel types as in MECS reporting [159].

Table B-0-1. Descriptions of fuel type categories

Fuel type categories in industrial boiler dataset

Fuel type category	Description
Biomass	Biomass gases, biogas, landfill gas, biodiesel, solid biomass
Coal	Includes anthracite, bituminous, subbituminous, and lignite coal; and coke
Natural gas	Pipeline natural gas
Oil products	Fuel oil, diesel, LPG, gasoline, kerosene
Other fuels	Fuel gas, process gas, propane, blast furnace and coke oven gas, black liquor, solid byproducts

Fuel type not reported	--

Fuel type categories in NREL thermal energy use in manufacturing dataset

Fuel type label	Description
Coal	Includes anthracite, bituminous, subbituminous, and lignite coal
Coke & breeze	Byproduct of baking bituminous coal and breeze (finely crushed coke)
Diesel	Diesel (no. 1, 2, and 4 diesel fuels) and distillate fuel oil (no. 1, 2, and 4 fuel oils)
LPG & NGL	Liquefied petroleum gas and natural gas liquids (ethane, ethylene, propane, propylene, butane)
Natural gas	Natural gas obtained from utilities, local distribution companies, and other suppliers
Residual fuel oil	No. 5 and 6 fuel oils
Other	Biomass, black liquor, still gas, waste gas, pet coke, blast furnace and coke oven gas

B.4 Electric Grid Case Descriptions and AEO Projections

This section details the U.S. Energy Information Administration (EIA)'s AEO projections for 2050 that informed the two future electric grid scenarios in our analysis. The AEO2021 cases are developed according to technical and macroeconomic assumptions. These assumptions are based on current laws and regulations as of September 2020 [300], current views on economic and demographic trends, compound annual growth rates for U.S. GDP, oil and natural gas resources and technology costs, and renewable technology costs [301]. The future reference case used in this analysis is based on the AEO2021 reference case, which is defined as the expected case given current laws, regulations, and trends. The future high renewables cased used in this analysis is based on a combination of the low oil and gas supply case and low cost renewables case [300] but is not an exact reflection of these cases nor any particular policies.

The electricity generation and grid mix by source for the current grid, as of 2019 [186], and the two future grid scenarios used in our analysis are shown in Table B-0-2. The percent change of electricity source was determined based on the change in electricity generation from the current year to the year 2050 in the AEO2021 projections [302], shown in Table B-0-3.

Table B-0-2. Electricity generation and grid mix by source for the current grid and two future grid cases

	Current grid (2019)		Future grid: Reference case			Future grid: High renewables case		
	Generation (BkWh)	Grid mix (%)	Percent change (%)	Generation (BkWh)	Grid mix (%)	Percent change (%)	Generation (BkWh)	Grid mix (%)
Natural gas	1590	38.4	10	1749	35.2	-30	1113	22.5
Coal	965	23.3	-40	579	11.7	-40	579	11.7
Nuclear	811	19.6	-27	592	11.9	-33	544	11.0
Renewables	729	17.6	180	2040	41.1	270	2696	54.6
Oil	25	0.6	-80	5	0.1	-80	5	0.1

Table B-0-3. Electricity generation for 2050 in U.S. EIA's AEO2021 reference case, low oil and gas supply case, and low cost renewables case

	AEO 2050 Reference case	AEO 2050 Low oil and gas supply case	AEO 2050 Low cost renewables case
	Generation (BkWh)	Generation (BkWh)	Generation (BkWh)
Natural gas	1752	829	1336
Coal	577	720	463
Nuclear	594	728	356
Renewables	2023	2580	2765
Oil	5	6	6

For the future high renewables case in our analysis, we combined the low oil and gas supply case and low cost renewables case by averaging the electricity generation by source to determine a percent change that reflected a considerable decrease in natural gas and coal. The future high renewables case is meant to show the level which grid decarbonization must reach for boiler electrification to lead to emissions savings. Furthermore, for the future grid scenarios, we apply the percent changes in electricity generation uniformly, and note that future research should consider regional variations in the future electric generation mix.

The carbon intensity of the grid in each scenario is shown in Chapter 4 in the main text. These carbon intensities are determined from the electricity sector carbon dioxide emissions rate in the U.S. EIA Annual Energy Review for the current grid (2019) [303] and in the AEO2021 projections in 2050 for the future grid scenarios [304, p. 18].

Appendix C. Supporting Information for Chapter 5

C.1 Unit Type Analysis of GHGRP and NEI Data

The figures in this section (Figure C-0-1– Figure C-0-5) show the distribution of unit types by total number of units, annual GHG emissions, and total capacity for individual facilities in a given manufacturing industry. Several example industries are shown for the GHGRP, reporting year 2021: Pulp Mills (322110), Organic Chemicals (325199); for the NEI, reporting year 2017: Cheese Manufacturing (311513), Sawmills (321113); and for the NEI with source classification code (SCC) unit descriptors: Plastics (325211). It should be noted that the names of unit types are not standardized across databases, so the names of unit types in the GHGRP are different from those in the NEI. Furthermore, in both databases, an "other" unit type is commonly reported. In the GHGRP, "Other combustion source (OCS)" is used, and in the NEI, "Unclassified" is used.

The NEI reports SCC codes, which is a classification of activities or equipment that generation emissions used by the U.S. EPA [222]. There are about 8,000 unique SCCs, and they are classified by four levels, with each level as a more specific subset of the former. For this analysis, common unit types are defined, and SCC codes are matched to the common unit types based on the descriptions of SCC levels. Figure C-0-6 shows the number of units with SCC codes matched to the defined unit types.

Figure C-0-1. Distribution of unit types by total number of units, GHG emissions, and total capacity for individual facilities in the Pulp Mills industry (322110) from GHGRP data

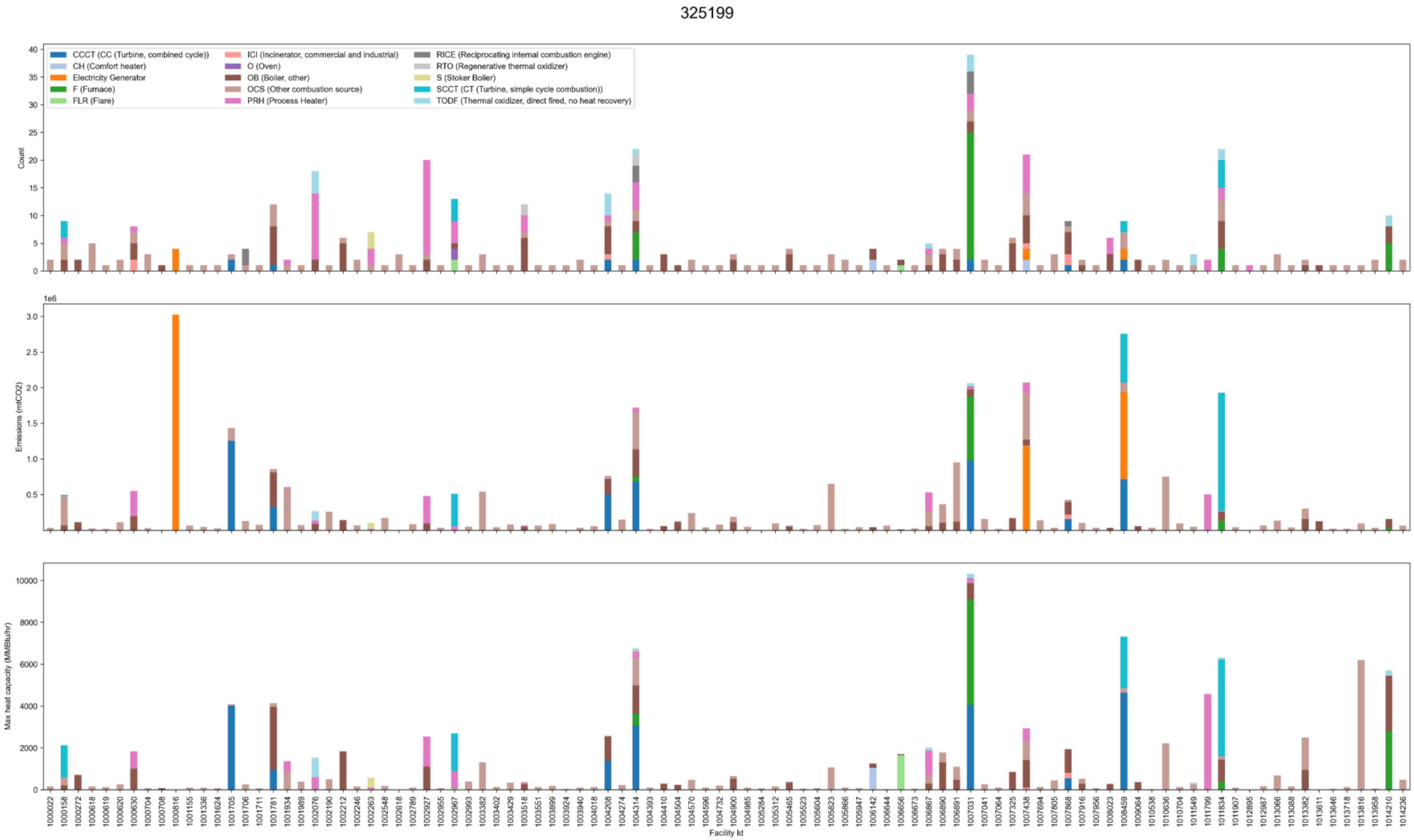

Figure C-0-2. Distribution of unit types by total number of units, GHG emissions, and total capacity for individual facilities in the Organic Chemicals industry (325199) from GHGRP data

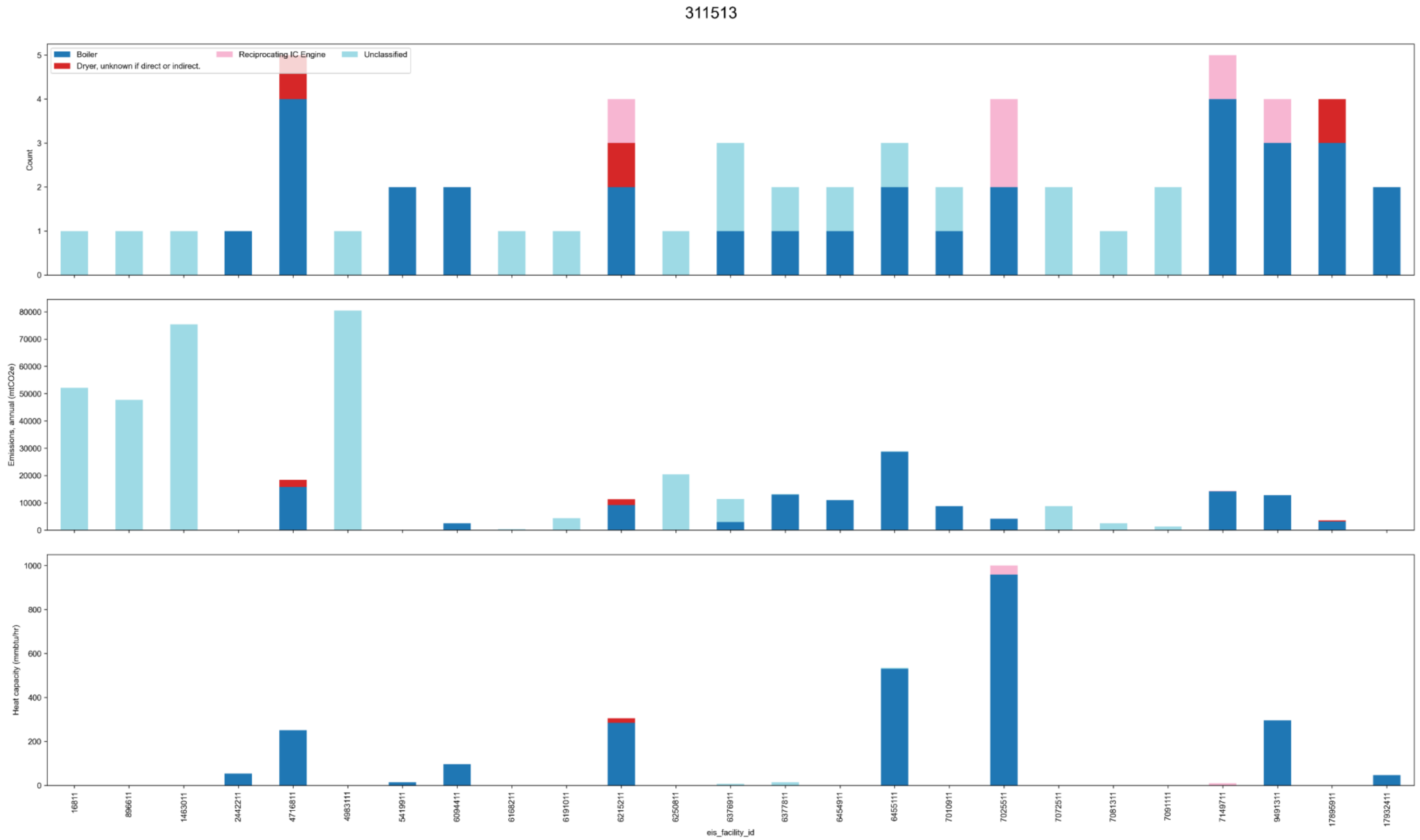

Figure C-0-3. Distribution of unit types by total number of units, GHG emissions, and total capacity for individual facilities in the Cheese Manufacturing industry (311513) from NEI data

Figure C-0-4. Distribution of unit types by total number of units, GHG emissions, and total capacity for individual facilities in the Sawmills industry (321113) from NEI data

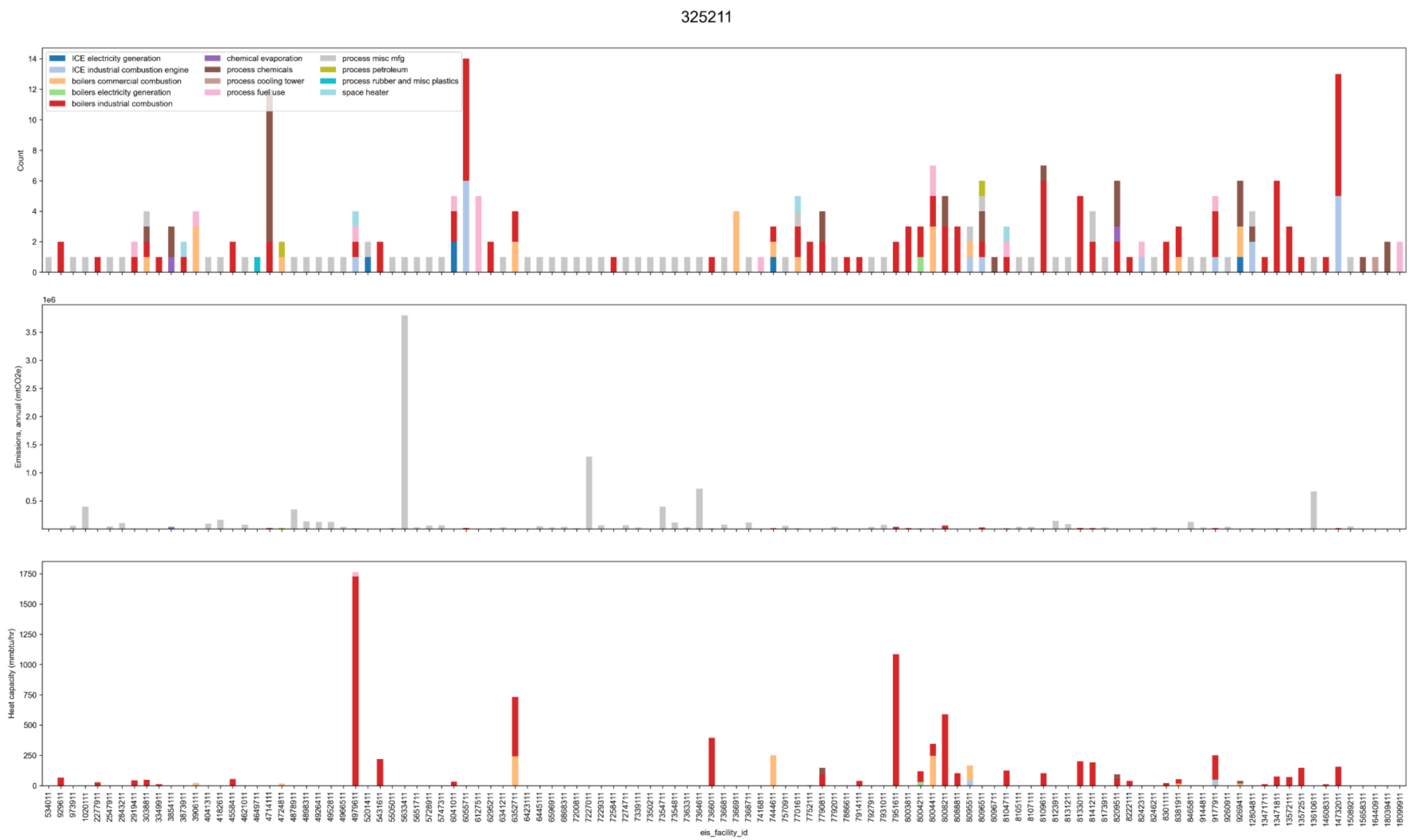

Figure C-0-5. Distribution of unit types by total number of units, GHG emissions, and total capacity for individual facilities in the Plastics industry (325211) from NEI data using SCC codes

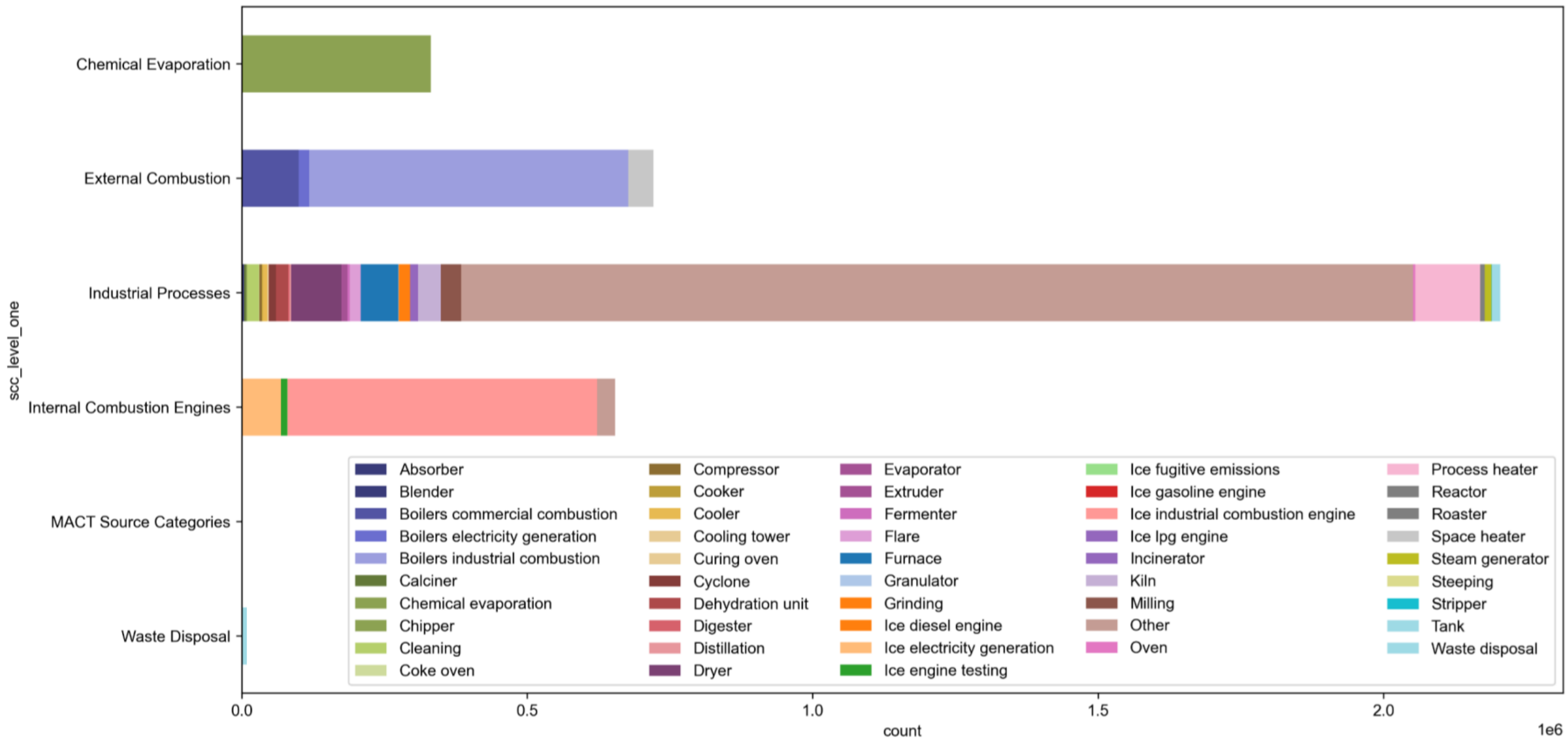

Figure C-0-6. Unit types defined for SCC codes in NEI data by SCC level one classifications. Colored bars represent the defined unit types. The length of bars represent the number of units with the specified unit type. Each item on the y-axis represents the level one classifications in SCC codes.

C.2 Coverage of Throughput and Energy Input Calculations from NEI Emissions

Of the units for which there are PM, SO_2, VOCs, NOx, and CO emissions in the NEI, throughput and energy input are calculated for a portion of the units based on available emissions factor data. Figure C-0-7 shows the breakdown of coverage for which throughput and energy are calculated by industrial subsector (3-digit NAICS).

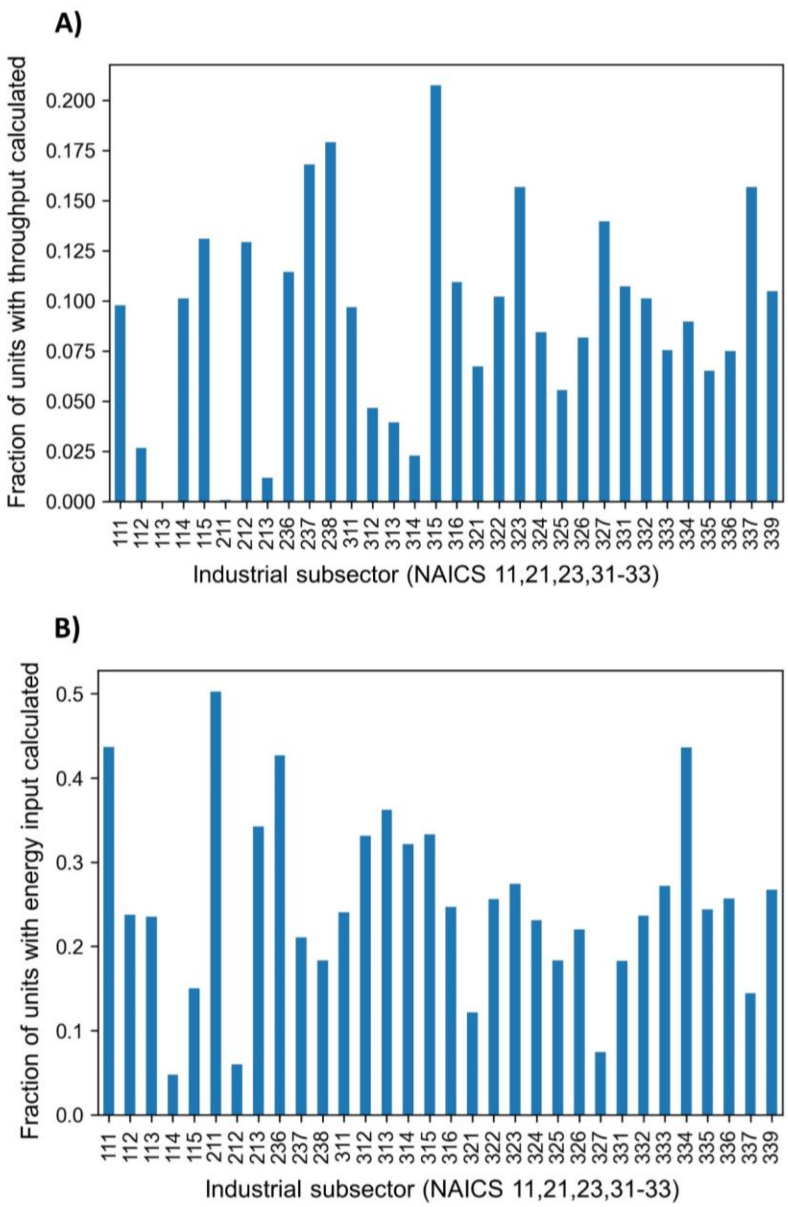

Figure C-0-7. Fraction of units with A) throughput and B) energy input calculated from NEI emissions by industrial subsector

Appendix D. Supporting Information for Chapter 6

D.1 List of Key Chemicals in NAICS Industries

Table D-0-1 shows a list of key chemicals in the six most energy-intensive chemicals industries in the United States. It should be noted that the list below is not exhaustive, and there are additional chemical products within each NAICS industry.

Table D-0-1. List of key chemicals in NAICS industries

NAICS description and code	**Chemicals**
Petrochemicals, 325110	Ethylene Benzene, Toluene, Xylene Propylene Styrene
Inorganic chemicals, 325180	Chlorine Hydrochloric acid Carbides Potassium compounds Sulfides and sulfites
Ethanol, 325193	Ethanol
Organic chemicals, 325199	Acetone Formaldehyde Isopropyl alcohol Silicone Biodiesels not from petroleum
Plastics, 325211	Polyethylene Polyethylene terephthalate (PET) Polyvinyl chloride (PVC) Polystyrene Epoxy resins
Ammonia (Nitrogenous fertilizers), 325311	Ammonia Fertilizers Urea

D.2 Energy use and production in plastics and petrochemicals industries

Figure D-0-1 shows the onsite energy use by end-use for the United States plastics industry. Process heating has the most onsite energy use, and over half is for steam-based heating. The fuels used for steam generation and for direct process heating are primarily natural gas (82%) and other gases (17%) [305].

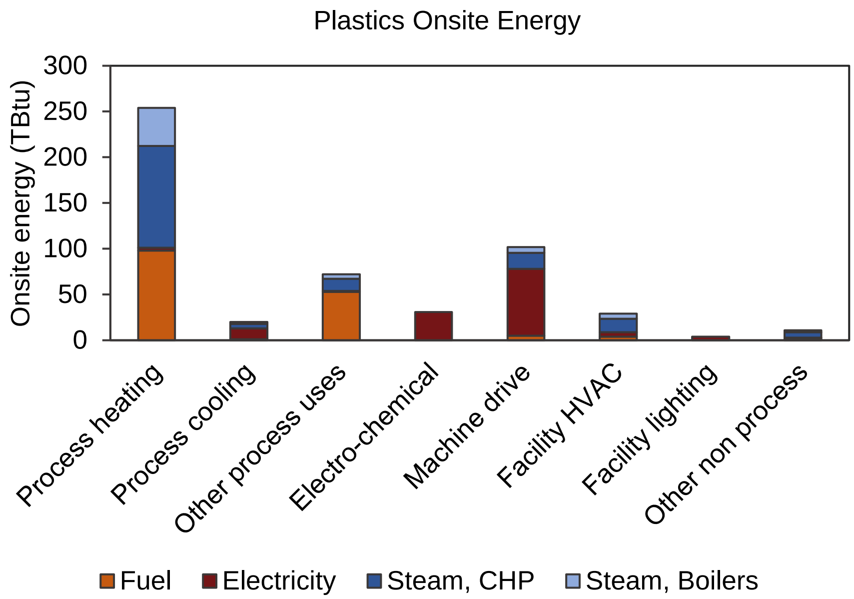

Figure D-0-1. Onsite energy use by end-use for the plastics industry (325211) in 2018. Colored bars represent the energy source or carrier. Data from **[305]**.

For steam based combustion units, boilers and combined heat and power (CHP) are most common. Figure D-0-2 shows the number of boilers and cogeneration, or CHP, units in plastics industry production facilities reporting emissions in the National Emissions Inventory database.

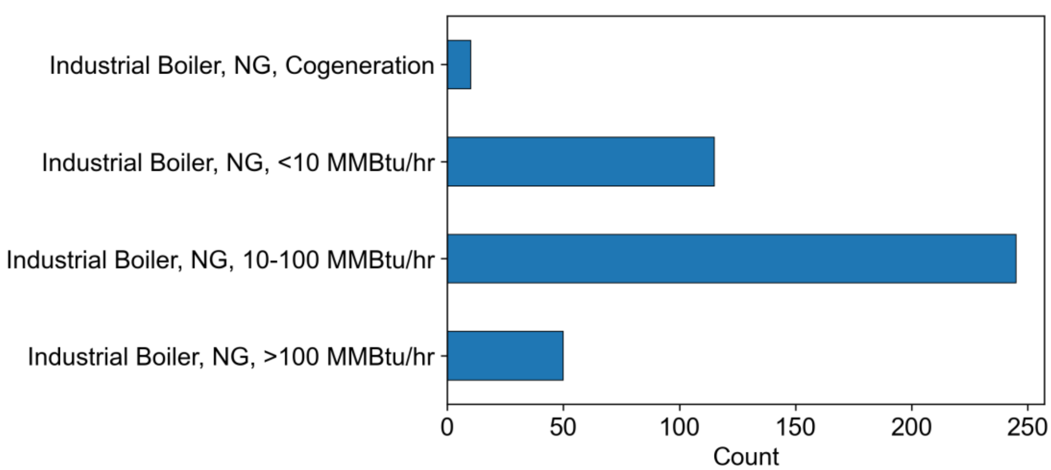

Figure D-0-2. Number of boiler and cogeneration (CHP) units in plastics production facilities (325211) reporting emissions in the NEI. Data from **[242]**.

Figure D-0-3 shows the annual production of plastics products in the U.S. in 2021. Linear low density polyethylene (LLDPE), high density polyethylene (HDPE), polypropylene (PP), and polyvinyl chloride (PVC) have the highest production volumes.

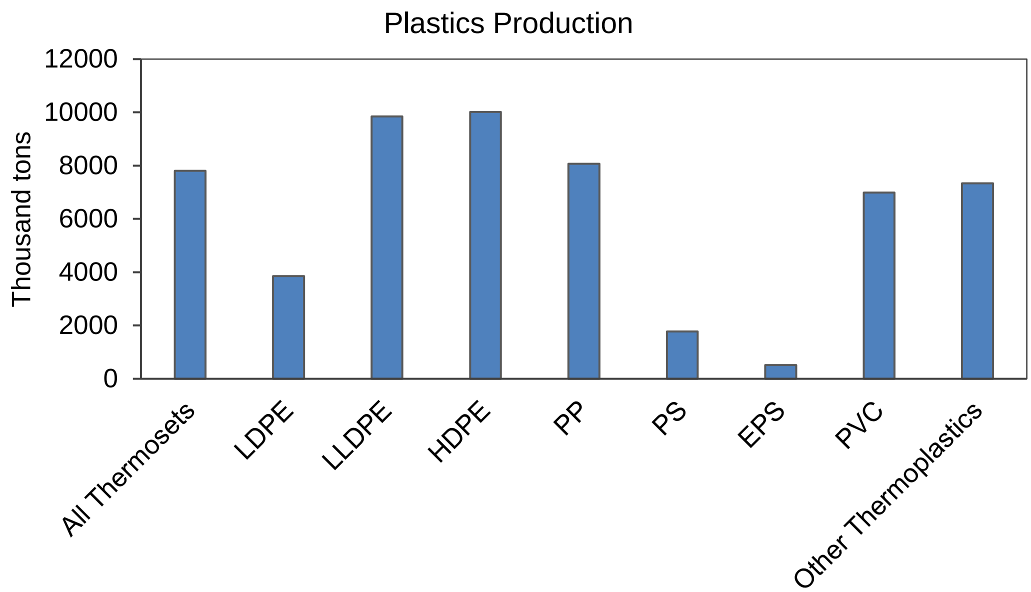

Figure D-0-3. Production of chemical products in the plastics industry in 2021. Data from **[306]**.

Figure D-0-4 shows the onsite energy use by end-use for the petrochemicals industry. Process heating has the most onsite energy use, and two thirds is met by direct-fired fuel combustion. The fuels used for direct process heating and steam generation are mostly natural gas (61%) and waste gases (31%) [307].

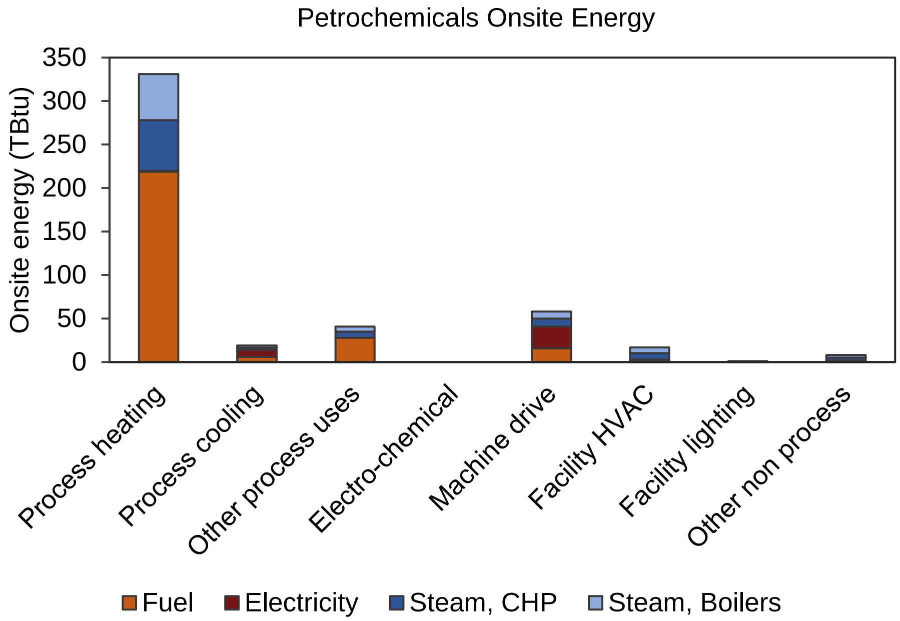

Figure D-0-4. Onsite energy use by end-use for the petrochemicals industry (325110) in 2018. Colored bars represent the energy source or carrier. Data from **[307]**.

Figure D-0-5 shows the annual production of petrochemical products in the U.S. in 2019. Ethylene has the highest production volume by far and is a precursor to plastics and other specialty chemicals.

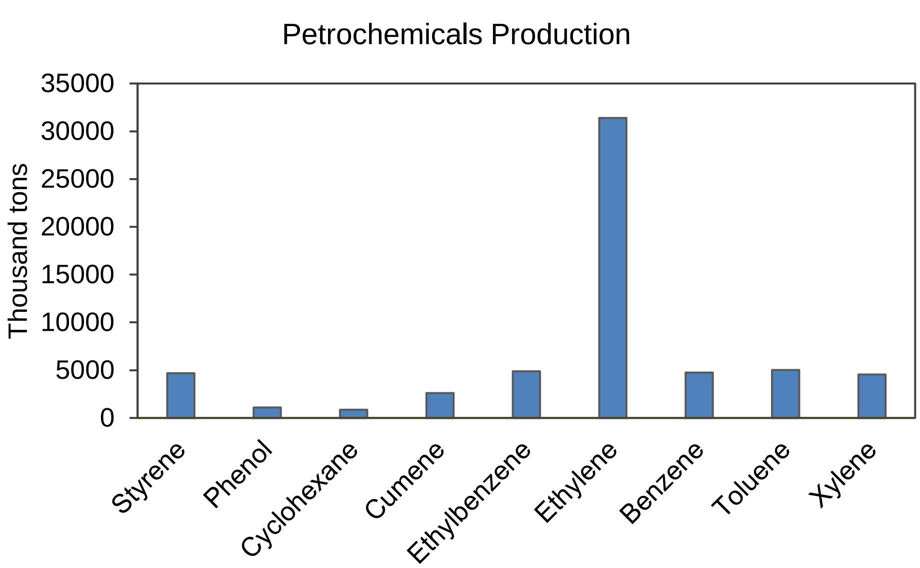

Figure D-0-5. Production of chemical products in the petrochemicals industry in 2019. Data from **[308]–[310]**.

D.3 Process Energy Data for Low Carbon Technology Cases

Table D-0-2 shows the unit processes in PVC production with vinyl chloride as the feedstock and the fuel and steam inputs by process. These process energy inputs are assumed to be steady state averages. While process energy from [266] was published in 1996, the source remains the most comprehensive set of unit process energy data to the best of our knowledge, and many industrial plants and equipment maintain operation around 20 years or more [283]. Other more recent publications with process energy data of chemical industries in the U.S. [311]–[313] also base their analysis on data from [266].

Table D-0-2. PVC unit process energy data. Data from **[266]**.

Unit process	**Fuel (MJ/t)**	**Steam (MJ/t)**	**Steam Temp. (ºC)**	**Electricity (MJ/t)**
Mixing tank				164.4
Reactor		609.1	121	99.5
Dumping tank		135.4	121	
Stripping compressor				283.8
Separator				
Condenser				
Distillation		9.5	121	
Condenser				
Blending tank				46.5
Centrifuge				66.3
Drying		695.4	188	
Separation/sizing				53.0
Blending		135.4	121	26.5
Melt compounding		342.1	146	74.4
Pelletizing				34.9
Drying		139.1	188	
Packaging				26.5
Boiler	2952			

Table D-0-3 shows the unit processes in ethylene production from ethane and the fuel and steam inputs by process. Since steam ethane cracking furnace accounts for 86% of fuel consumption in ethylene production based on the data below, the process is selected as one of the two case studies for this analysis. However, in the energy, environmental, and cost analyses, a more recent estimation of the energy demand for steam ethane cracking is used (13,807 MJ/t of ethylene), which is based on 2010 data from [273]. In this case, the process energy data below is used to determine the steam cracking furnace as the process of interest, and then energy consumption data from the more recent source is used in our calculations.

Table D-0-3. Ethylene unit process energy data. Data from **[266]**.

Unit process	**Fuel (MJ/t)**	**Steam (MJ/t)**	**Steam Temp. (ºC)**
Furnace/Cracker	20119	1182	177
Waste heat boiler			
Quench			
Compressor			
Acetylene removal		588	121
Compressor			
Cooler/condenser			
Methane separation			
Heavy separation		1570	149
Ethane separation			
Prime mover CHP			
Boiler	3291		
Chiller			

In the PVC case study, with hydrogen-blended boilers, the amount of hydrogen was set at 30% by volume. To calculate the energetic amount of hydrogen and natural gas needed to meet the process heat demand, the following properties of hydrogen and natural gas as shown in Table D-0-4 are used.

Table D-0-4. Properties of Natural Gas and Hydrogen. Data from **[314]**.

	Energy content, HHV (Btu/lb)	**Density (lb/scf)**
Natural gas	22453	0.05
Hydrogen	61013	0.0056

The process heat demand for steam generation in PVC production is estimated at 2,066 MJ/t, and assuming a boiler combustion efficiency of 80%, 2,583 MJ/t of fuel is needed. It was calculated that 1,933 scf/t of natural gas (2,290 MJ/t) and 813 scf/t of hydrogen (293 MJ/t) are needed to meet the process heat demand. Furthermore, the change in natural gas usage based on varying levels of hydrogen-blending was evaluated. Figure D-0-6 shows the reduction in natural gas usage for the volumetric percentage of hydrogen in a hydrogen-natural gas blend.

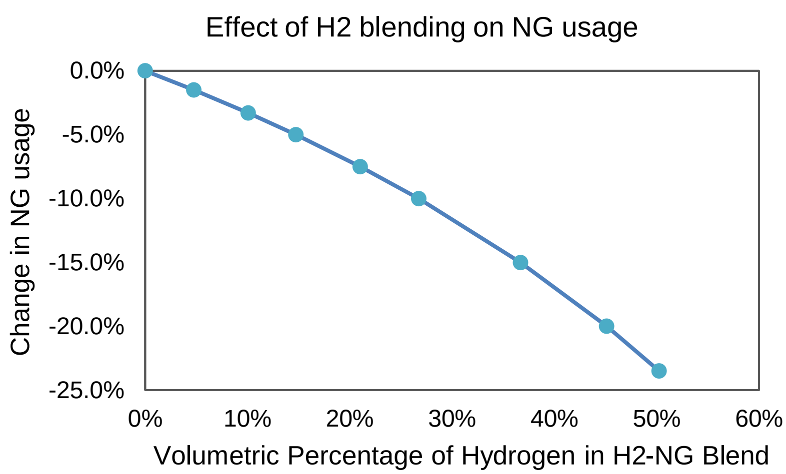

Figure D-0-6. Effect of hydrogen (H2) blending on natural gas (NG) usage

The primary energy for process heat applications varies by technology and heat source and provides further insight on overall efficiency in energy usage. Primary energy was calculated for each technology case based on the energy inputs in Table 2 of the main text and on the efficiencies in electricity generation source (from power plant efficiency values [274],[315]), the grid makeup of respective regional grids [316], a transmission loss factor of 4.9%, hydrogen production efficiencies of 69% for PEM electrolysis [317] and 66% for steam methane reforming with carbon capture, and efficiency losses of 8.6% with hydrogen compression and cooling [274]. The estimations of primary energy for each technology case are shown in Figure D-0-7 and Figure D-0-8.

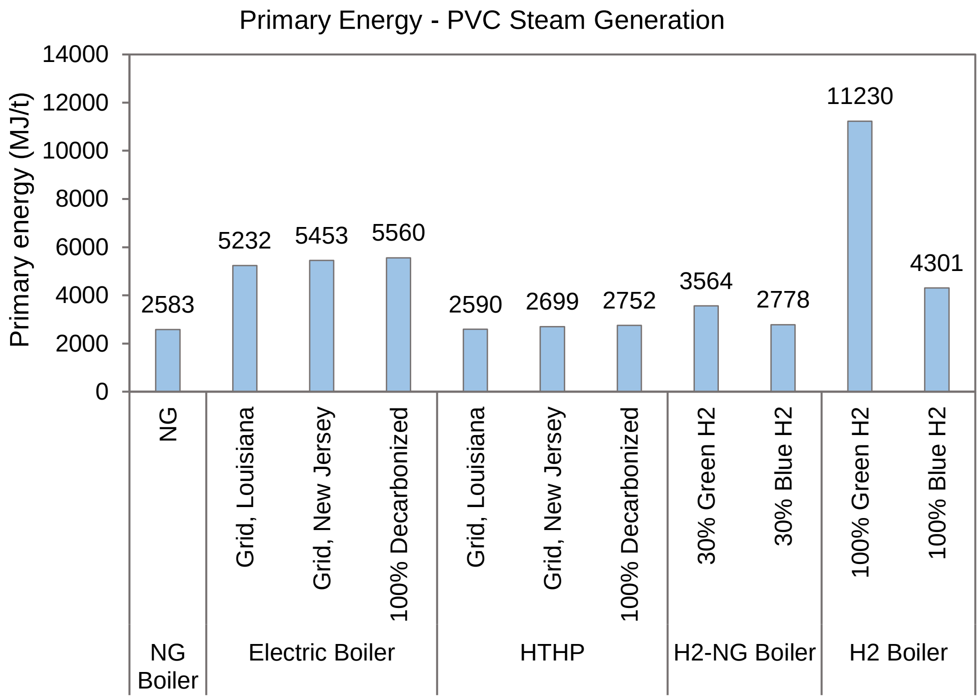

Figure D-0-7. Estimated primary energy of process heat technologies for steam generation in PVC production

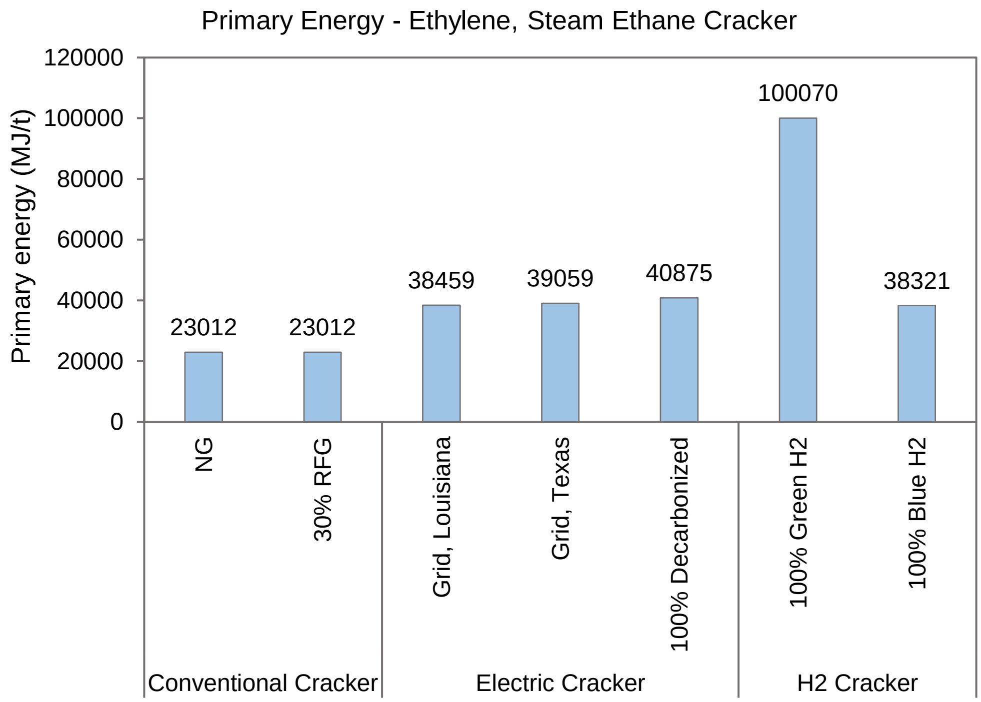

Figure D-0-8. Estimated primary energy of process heat technologies for the steam ethane cracker in ethylene production

D.4 CAPEX and OPEX Assumptions

CAPEX includes equipment and installation costs, and OPEX includes fixed operations and maintenance costs but not fuel or energy costs. For the PVC case, the CAPEX of boilers and heat pumps is based on a 10MW capacity heat system. An estimation of an electric boiler investment cost is 100,000 USD2018/MW [284], which is 40% higher than conventional boilers [285]. An estimation of the OPEX of conventional industrial boilers is 2.5% of its CAPEX [286], [287], and of electric boilers, about 1% of its CAPEX [288]. The CAPEX of heat pumps is 300-900 Euro/kW, with an average around 300-400 Euro/kW [289], and the OPEX of heat pumps is estimated at 3% of CAPEX [290]. Hydrogen-blended boilers are assumed to have the same investment costs and OPEX as conventional boilers. The CAPEX of 100% hydrogen boilers is estimated to be about

20% higher than conventional natural gas industrial boilers [291], and the OPEX is estimated at 1% of CAPEX [288].

For the ethylene case, the CAPEX of conventional steam ethane crackers is estimated at 1,500 USD/t, and fixed OPEX is estimated at 2.5% of CAPEX [292]. While an electric cracker has not yet been commercially developed, it is estimated that costs would range from 3.5-5 million Euros (in 2018) per MW [272], which is about twice the CAPEX of a conventional cracker, so we assume the electric cracker CAPEX is 3,000 USD/t. The OPEX of an electric cracker is estimated at 2% of CAPEX [272]. A hydrogen-fueled cracker has an estimated CAPEX of 0.5-1.5 million Euros (in 2018) per MW [272], and for a 1,000 MW unit [318], the CAPEX would be similar to the conventional cracker. The OPEX for a hydrogen-fueled steam cracker is estimated at 1% of CAPEX [272]. Overall, we acknowledge that the CAPEX of emerging technologies could reduce over time as the deployed stock of technologies increases; however, since this analysis assumes new equipment is installed once, we do not include learning rate cost reductions in CAPEX.

D.5 Industrial Energy Cost Data

Table D-0-5 and Table D-0-6 provide projected industrial fuel, electricity, and hydrogen prices by region for the base year 2022 through 2042.

Table D-0-5. Industrial fuel, electricity, and hydrogen prices for the West South Central region

Louisiana & Texas (West South Central)

Year	NG (USD/MMBtu)	NG (USD/MJ)	Electricity (USD/MMBtu)	Electricity (USD/MJ)	Green H2 (USD/kgH2)	Green H2 (USD/MJ)	Blue H2 (USD/kgH2)	Blue H2 (USD/MJ)
2022	6.84	0.00648	20.8	0.0197	2.79	0.0197	2.00	0.0141
2023	5.62	0.00533	20.6	0.0195	2.71	0.0191	2.00	0.0141
2024	4.46	0.00423	20.2	0.0192	2.63	0.0186	2.00	0.0141
2025	3.90	0.00370	19.2	0.0182	2.55	0.0180	2.00	0.0141
2026	3.48	0.00330	18.3	0.0174	2.48	0.0175	2.00	0.0141
2027	3.27	0.00310	17.8	0.0169	2.40	0.0169	2.00	0.0141
2028	3.22	0.00305	17.4	0.0165	2.32	0.0164	2.00	0.0141
2029	3.25	0.00308	17.4	0.0165	2.24	0.0158	2.00	0.0141
2030	3.34	0.00317	17.6	0.0167	2.16	0.0153	2.00	0.0141
2031	3.49	0.00331	17.8	0.0169	2.08	0.0147	2.00	0.0141
2032	3.64	0.00345	17.8	0.0169	2.01	0.0142	2.00	0.0141
2033	3.82	0.00362	18.4	0.0174	1.93	0.0136	2.00	0.0141
2034	3.97	0.00376	18.6	0.0177	1.85	0.0131	2.00	0.0141
2035	4.09	0.00388	18.7	0.0177	1.77	0.0125	2.00	0.0141
2036	4.11	0.00389	18.9	0.0179	1.69	0.0119	2.00	0.0141
2037	4.14	0.00392	19.1	0.0181	1.61	0.0114	2.00	0.0141
2038	4.26	0.00404	19.3	0.0183	1.54	0.0108	2.00	0.0141
2039	4.18	0.00397	19.4	0.0184	1.46	0.0103	2.00	0.0141
2040	4.33	0.00410	19.5	0.0185	1.38	0.0097	2.00	0.0141
2041	4.41	0.00418	19.8	0.0188	1.30	0.0092	2.00	0.0141

Table D-0-6. Industrial fuel, electricity, and hydrogen prices for the Middle Atlantic region

New Jersey (Middle Atlantic)

Year	NG (USD/MMBtu)	NG (USD/MJ)	Electricity (USD/MMBtu)	Electricity (USD/MJ)	Green H2 (USD/kgH2)	Green H2 (USD/MJ)	Blue H2 (USD/kgH2)	Blue H2 (USD/MJ)
2022	7.34	0.00695	28.6	0.0272	4.57	0.0323	2.50	0.0177
2023	7.19	0.00681	27.9	0.0264	4.57	0.0323	2.50	0.0177
2024	6.19	0.00587	27.3	0.0259	4.57	0.0323	2.50	0.0177
2025	5.59	0.00530	26.1	0.0248	4.57	0.0323	2.50	0.0177
2026	5.13	0.00486	25.1	0.0238	4.57	0.0323	2.50	0.0177
2027	4.83	0.00458	24.5	0.0232	4.57	0.0323	2.50	0.0177
2028	4.66	0.00442	24.0	0.0227	4.57	0.0323	2.50	0.0177
2029	4.65	0.00440	23.7	0.0224	4.57	0.0323	2.50	0.0177
2030	4.59	0.00435	23.5	0.0222	4.57	0.0323	2.50	0.0177
2031	4.61	0.00437	23.4	0.0222	4.57	0.0323	2.50	0.0177
2032	4.65	0.00441	23.6	0.0224	4.57	0.0323	2.50	0.0177
2033	4.73	0.00448	23.8	0.0225	4.57	0.0323	2.50	0.0177
2034	4.78	0.00453	23.8	0.0226	4.57	0.0323	2.50	0.0177
2035	4.83	0.00458	23.6	0.0224	4.57	0.0323	2.50	0.0177
2036	4.87	0.00461	23.8	0.0225	4.57	0.0323	2.50	0.0177
2037	4.94	0.00468	23.8	0.0225	4.57	0.0323	2.50	0.0177
2038	5.04	0.00478	24.1	0.0228	4.57	0.0323	2.50	0.0177
2039	5.07	0.00481	24.5	0.0232	4.57	0.0323	2.50	0.0177
2040	5.12	0.00485	24.6	0.0233	4.57	0.0323	2.50	0.0177
2041	5.17	0.00490	24.7	0.0234	1.30	0.0092	2.50	0.0177

D.6 Cost of Abatement

Figure D-0-9 shows the cost of abatement curve for the low carbon steam generation options in PVC production. The cost of abatement is plotted against the abatement potential, which is the total amount of emissions reductions that would result from adopting the technology in a typical PVC facility, shown for both Louisiana (LA) and New Jersey (NJ).

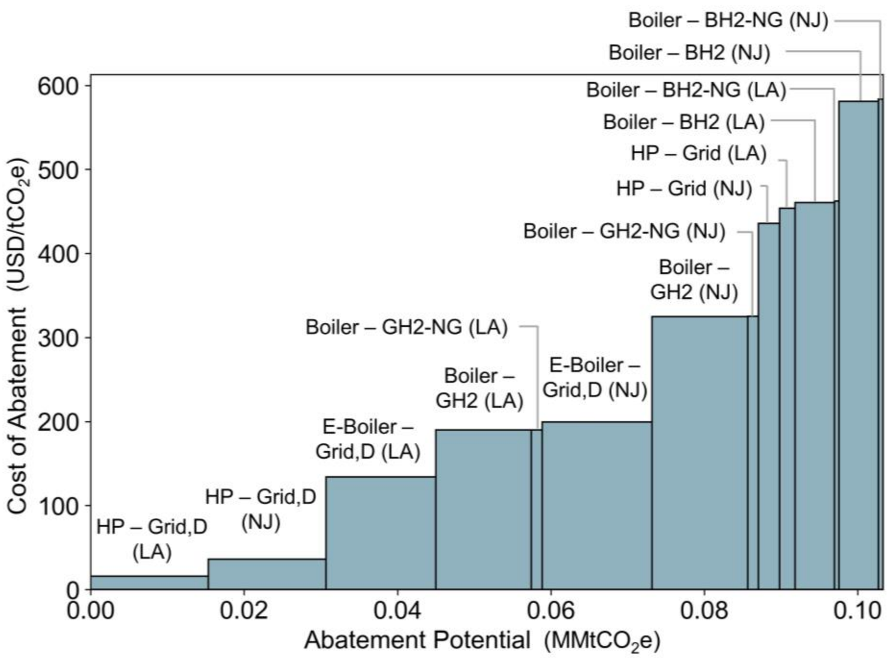

Figure D-0-9. Cost of abatement curve for low carbon steam generation options in PVC production. GH2 is green hydrogen; Grid, D is decarbonized grid, BH2 is blue hydrogen.