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Electrification Potential of U.S. Industrial Boilers and Assessment of the GHG Emissions Impact

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Abstract

Electrification is a key strategy for decarbonizing the industrial sector. Industrial process heating, which still relies heavily on fossil fuel combustion and accounts for the majority of sector wide GHG emissions, is a particularly attractive electrification target. Electrifying industrial boilers represents a cross-cutting opportunity for GHG emissions reductions, given their widespread use in most manufacturing industries. Yet, there are gaps in the understanding of the current population of conventional industrial boilers in the United States that preclude a characterization of boiler electrification's technical potential to reduce fuel consumption and GHG emissions. In this study, we develop an up-to-date dataset of the industrial boiler population in the U.S. and quantify the county-level electricity requirements and net changes in fuel use and GHG emissions under the current electric grid and theoretical future grid scenarios. Our results show an increase of 105 MMmtCO₂e and 73 MMmtCO₂e in GHG emissions from boiler electrification, with and without the replacement of byproduct fuels, respectively, under the current electric grid. GHG emissions savings are currently possible only in certain regions of the U.S. unless future grids are decarbonized. We also provide recommendations for policy makers and manufacturing facilities that would advance the electrification of industrial boilers in locations and industries toward fuel savings and GHG emissions reductions.

Keywords: Industrial boiler dataset; Boiler capacity characterization; Electrification; Greenhouse gas (GHG) emissions impact

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 [1], the immediate deployment of commercially available clean energy technologies is vital [2]. 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 [3], industrial boilers represent a cross-cutting technology with significant potential for electrification.

In the U.S., manufacturing industries are responsible for 23% of all energy-related carbon dioxide (CO₂) emissions, and process heating accounts for 31% of CO₂ emissions within manufacturing [4], [5]. 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 [6]. 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 [7]. 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 [7]–[11]. 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 [12], 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 [13]–[16]. Electric boilers have high thermal efficiency (~99%), fast ramp-up times, and low downtime [13] and require no onsite pollution abatement, combustion accessories, such as tanks, fuel links, and exhaust flues, or expensive combustion inspection [17]. 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 [13]. Electric boilers could significantly increase electricity capacity at industrial plants [13] [14], but they can also be operated flexibly to utilize low-cost power supply from renewables [15] and support increased renewable generation [16]. 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. Additionally, 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 [18] and in Europe [19] 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 MMmtCO₂e/year from electrifying industrial boilers in Germany in 2020 and a decrease of 5.9-15.9 MMmtCO₂e/year in 2050, assuming an 80-95% reduction in electricity carbon intensity in 2050 [18]. Several reports centered on U.S. electrification of industry evaluate electric boilers, but either assume limited adoption relative to other electrotechnologies [20] or simplify their accounting of fuel use in a high-level, national analysis [21]. Hasanbeigi et al. estimate savings of 140 TBtu in final energy of industrial boilers and an initial increase in CO₂ emissions, followed by a decrease of 1,000 MMmtCO₂/year by 2050, assuming future grid decarbonization [21]. However, these findings based on aggregated national manufacturing energy data [22] 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 U.S., 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. 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.

2. Methods

This analysis extends previous work documented in [23] 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) [24], the Boiler Maximum Achievable Control Technology (MACT) Draft Emissions and Survey Results Database [25], and the National Emissions Inventory (NEI) [26]. 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 [7] 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 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.

2.1 Data sources for industrial boiler characterization

Descriptions of the GHGRP, MACT, and NEI databases and the categories of data included in this study are described in Table 1, and the process of integrating data is described in Section 2.2.

Table 1. Descriptions of the GHGRP, MACT, and NEI databases [27]–[29]

	GHGRP	MACT	NEI
Main data reported	Unit-level GHG emissions (CO ₂ , CH ₄ , N ₂ O)	Unit-level air pollutants (CO, NO _x , 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 mtCO ₂ e/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 1.

2.2 Data integration and development of industrial boiler dataset

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 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 the supporting information (SI) Figures S1 and S2.

Figure 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 [30], 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 Eq. 1. Operating hours data are taken from the GHGRP and averaged for each subsector.

$$F_{inv} = C_{c,N} * t_N \quad (\text{Eq. 1})$$

We encounter two cases 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 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. 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. 2. The median installed boiler capacity is used in Eq. 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. 3.

$$\left\{ \begin{array}{l} \text{Case 1: } F_{inv}(=0) < F_{c,N}; \quad b = \frac{F_{c,N}}{t_N * C_N} \quad (\text{Eq. 2}) \\ \text{Case 2: } F_{inv} < F_{c,N}; \quad b = \frac{(F_{c,N} - F_{inv})}{t_N * C_{c,N}} \quad (\text{Eq. 3}) \end{array} \right.$$

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.

2.3 Calculations of electrification potential and net changes in boiler fuel use 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 [31]. 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% [32]. 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 [23]. 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:

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

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 2). Electric boiler efficiency is assumed to be 99% [31].

Table 2. Conventional boiler efficiencies by fuel type [33], [34].

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 [35] and the resource mix of fuels used in regional electric grids and accounts for grid losses (Fig. 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 [36] and fuel cycle emissions factors from the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model [37]. 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 [38].

Figure 2. (a) Flow diagram for calculating net changes in GHG emissions of boiler electrification with (b) eGRID electricity heat rate data [35] 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 the next section.

3. Results and Discussion

3.1 Industrial boiler characterization

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 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 is shown in Figure 3. The total number of boilers is compared to the estimated count of industrial boilers from 2005 [12] and to the number of U.S. manufacturing establishments overtime [39] to assess the validity of our results. These and additional comparisons between our assessment and [12] are described further in the SI.

Figure 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 falls 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 [40]. 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 [39]. 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 [41]. 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 [42], [43]. 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 [39], with many steam-intensive processes [44].

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 [40], 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 (Fig. 4a) 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 [9]. Similarly, the wood and paper subsectors use black liquor, a biomass byproduct of the Kraft process for converting wood to pulp and paper [45], for 40% of its onsite fuel consumption [8]. In the iron and steel industry, blast furnace and coke oven gases make up 27% of fuel consumption [11], 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.

(a)

(b)

Figure 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 4b, 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 5 shows the estimated numbers of boiler units and total installed capacities per county.

Figure 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 [46].

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 3.1 due to differences in fuel type classification between the Table 1 databases and MECS data (see Table S1 for more detail). Figure 6 shows both estimated boiler fuel consumption by fuel type and the calculated electrification potential, totaled for each manufacturing subsector.

Figure 6. Conventional boiler fuel consumption by fuel type and NAICS manufacturing subsectors [7] (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 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) [47]. 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 [48].

3.3 Net changes in boiler 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 U.S., according to eGRID 2019 data [49]. The fuels inputs necessary for the electricity required by electric boilers are compared to onsite fuel savings, or avoided fuels, from conventional boilers (Fig. 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 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 [49]. 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 [50]. 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) projections [51], 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. For each

scenario, the percent change in electricity generation of coal, natural gas, oil, and renewables from current levels is shown in Figure 8a.

Despite a considerable increase in renewables and a 25% 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 (Fig. 8b). Consequently, in this future reference case and with the current grid, there is a positive net change in GHG emissions, indicating that more GHG emissions are released at the nationwide level as a result of boiler electrification. GHG emissions would increase by 105 MMmtCO_{2e} using the current grid and 84 MMmtCO_{2e} using the future reference grid. The effects of increased fuel use and GHG emissions also occur with 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.

Figure 8. (a) 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). **(b)**

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) [5]. 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, there are counties in the U.S. where the adoption of electric boilers would lead to reductions in GHG emissions today (Fig. 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 [52]. 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.

Figure 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

Similarly, in the future reference case grid, the California, New York, and Northeast counties show reductions in GHG emissions, but there are some counties with pronounced differences. For instance, in California, some counties show a smaller GHG emissions reduction than with the current grid due to the increase in natural gas-based electricity under the future reference case scenario in a subregion which relies on natural gas more than any other source. Conversely, in several counties in the Northwest and West, which rely less on natural gas and more on coal for electricity, the 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, a more expansive area of the country is shown have GHG emissions reductions.

4. Conclusions

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. In this study, we developed an up-to-date industrial boiler dataset that characterizes boilers by county, manufacturing subsector, installed capacity, and fuel type. This comprehensive dataset integrates multiple national facility-level emissions databases, serves as an updated resource for the U.S. industrial boiler population, which prior to this study has not been updated in nearly twenty years, and provides characteristics of conventional boilers traced to individual units. In the second major contribution of this study, we quantified the county-level electrification potential and net changes in fuel use and GHG emissions for industrial boilers under multiple electric grid scenarios. For these analyses, we calculated the steam demand of boilers based on conventional boiler fuel consumption and the required electrical energy for electric boilers, accounted for the use of byproduct fuels in the potential to electrify boilers, and considered the full fuel cycle GHG emissions.

Our results show that the largest electrification potential of industrial boilers is in the chemicals, refining, and food subsectors, when excluding boilers using byproduct fuels from potential replacement with electrification. We find that electrifying boilers leads to an overall increase in fuel use and GHG emissions under the current electric grid, 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. In the future reference grid scenario, where coal is reduced from the electric grid mix and natural gas is increased, overall fuel use and GHG emissions would still increase. There would only be an overall GHG emissions reduction in the high renewables grid scenario, where both the percentage of coal and natural gas in the electric grid mix decrease significantly.

In this regard, our study is consistent with past work [18]–[21], but it uniquely contributes a more granular understanding of boiler electrification in the U.S. With consideration of county-level fuel consumption of boilers and the regional electric grid resource mixes, the GHG emissions impacts from changes in power generation can be shown by county and subsector. This detail offers policy makers a direct roadmap for policy development that considers regional factors. Our scenario analysis demonstrated the sensitivity of results to coal and natural gas in the electric grid and, more broadly, the importance of accelerating grid decarbonization for industrial electrification technologies to be worthwhile. In particular, this work emphasizes the need for reducing emissions in the life cycle of electricity generation, such as upstream natural gas leakage [53] and the adoption of carbon capture and sequestration (CCS) in coal and natural gas power plants.

Moreover, since our analysis showed that industrial boiler electrification would not lead to fuel and GHG emissions savings uniformly throughout the U.S., manufacturing facility decision makers and policy makers should consider the following recommendations. First, electrification should be targeted initially at facilities and locations where our results indicate the most promise for reducing fuel consumption and GHG emissions. Additionally, economic incentives for electric boilers should be pursued to facilitate their adoption. Second, for facilities and locations where fuel and emissions savings are not immediately apparent, reducing steam demand in plant processes through efficiency measures can reduce the needed replacement capacities, which could improve the overall investment economics considerably [54]–[56]. Third, possible economic co-benefits of boiler electrification (e.g., reduced pollution abatement costs, smaller equipment footprints) should be accounted for, which could also improve the economics of

electric boiler investments. Policy makers can assist by providing best practice costing guidance to capture these important co-benefits in investment analyses. Finally, for boilers that are likely to continue using byproducts or residues as fuels, CCS could be implemented instead of stranding the byproducts, which may be combusted in another way.

This research on industrial boiler technology, energy, and emissions data addressed knowledge gaps about the climate change mitigation potential of electric boilers but also revealed several areas for future research. First, future research should 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. Second, future research should address the significant electricity load additions from industrial electrification and integrate grid modeling that considers baseload and intermittent sources at a temporal scale. Third, future work should consider heat pumps as an alternative electrified heating technology 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 should investigate facility-level costs associated with the electrification of boilers and the policies that lead to a decarbonized electric grid and a transition from fossil fuel-based technologies.

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Data and code availability

The industrial boiler dataset and all code is available at the following GitHub repository:
<https://github.com/carriescho/Electrification-of-Boilers>.

Appendix: Supporting Information

Document available for download.

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