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What is the role of distributed energy resources under scenarios of greenhouse gas reductions? A specific focus on combined heat and power systems in the industrial and commercial sectors

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Abstract

Combined heat and power (CHP) is promoted as an economical, energy-efficient option for reducing air emissions, mitigating carbon emissions and reducing reliance on grid electricity. However, its potential benefits have only been analyzed within the context of the current energy system. To fully examine the viability of CHP as a clean-technology alternative, its growth must be analyzed considering how the energy sector may transform under the influence of various technological and policy drivers that are specifically geared toward limiting greenhouse gas (GHG) emissions. Scenarios were developed through a bottom-up technology model of the U.S. energy system to determine the impacts on CHP development and both system-wide and sectoral GHG and air pollutant emissions. Various scenarios were considered, from CO_2 emissions reductions in the electric generating units (EGU) sector to GHG reductions across the whole energy system while considering levels of CHP investment. The largest CHP investments were observed in scenarios that limited CO_2 emission from the EGU sector alone. The investments were scaled back in the scenarios that incorporated energy system level GHG reductions. The energy system level reduction scenarios yielded rapid transformation of the EGU sector towards zeroemissions technologies as reliance on electricity increases with the electrification of the many end-use sectors such as buildings, transportation and industrial sectors, reducing investment in CHP. The prime mover and fuel choice heavily influenced the air pollutant emissions resulting in trade-offs among pollutants including GHG emissions. The results suggest that CHP could play a role in a future low-carbon energy system, but that role diminishes as carbon reduction targets increase.

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1. Introduction

According to the recently released U.S. Greenhouse Gas Inventory (GHGI) report [1], the U.S. emitted 5569 Million Metric Ton (MMT) of CO_2 in 2014, while rest of the world emitted around 33.9 Giga Metric Ton (GT) of CO_2 [2]. The portion of total GHG emissions in the U.S. attributed to industrial and commercial sectors is 20% and 13.2%, respectively [1]. This combined 33.2% figure includes both direct and indirect combustion (i.e., including emissions associated with electricity generation). Fuel combustion and industrial processes contributing to the majority of the GHGs are also causing local air pollution in communities and impacting air quality [3]. Fuel switching and the adoption of efficient technologies in industrial and commercial sectors can simultaneously reduce emissions, and fuel savings induced by energy efficient technology adoption can translate into economic benefits. However, according to Davis et al. (2018), 37% of the global CO_2 emissions attributed to some industrial sectors such as iron and steel and cement sectors and load-following electricity are difficult to eliminate due to heavy reliance fossil fuel combustion [2]. A significant portion of the load following electricity meets daytime electric demand from buildings, specifically commercial buildings. Typically, industrial and commercial facilities meet their electricity needs from the centralized grid and satisfy their steam demands using an on-site boiler. One way to achieve energy efficiency and reduce the use of the centralized grid is the use of combined heat and power (CHP) systems to provide high quality steam along with electricity for various end-use demand needs. The U.S. Environmental Protection Agency (EPA) defines CHP as an efficient and clean approach for generating electricity and useful thermal energy from a single fuel source [4].

The U.S. EPA CHP partnership gathers data and promotes the development of CHP in the industrial and commercial sectors in the U.S. Liu et al. (2014) provides a thorough summary of available existing prime mover technologies to drive a CHP system and a review of CHP systems around the world [5]. Due to its distributed nature, CHP could be a reliable hedging alternative against major disruptions in the grid, and therefore can also contribute to the resiliency of communities. Dieleman (2013) noted that the vitality or resilience of a system depends on the balance between centralization and decentralization of the infrastructure system [6]. Hospitals and colleges (categorized under the commercial sector) are good candidates for CHP, as CHP systems can continue to generate power during major grid outages and can also mitigate peak load on the grid. For example, New York Presbyterian Hospital installed a 7.5 MW CHP system fulfilling 100% of the electricity and steam needs for the hospital. It is believed to have been the first in New York City capable of operating independently from the grid in the event of a power outage [7]. Besides, multiple reports by the American Council for an Energy-Efficient Economy (ACEEE) characterize CHP as a resource for both energy efficiency and resilience to extreme weather events [8,9].

Historically, before the advancement of centralized electric power stations as the dominant source of electricity, CHP systems were used to deliver energy to industrial and municipal facilities [10]. During the oil crisis of 1978, the U.S. Congress enacted the Public Utilities Regulatory Policies Act (PURPA) to encourage greater energy efficiency. PURPA provided various regulatory exemptions for energy-efficient “qualified facilities” (QFs) and required electric utilities to purchase excess electricity generated from these QFs and to provide them with reasonable standby rates and backup charges. Tax credits offered by the Energy Tax Act of 1978 and the Windfall Profits Tax Act of 1980 also helped to spur investments in CHP capacity [11]. However, in the early 2000s, electric utilities began to oppose the requirements of PURPA, and Congress responded to these concerns with the Energy Policy Act of 2005, which allowed utilities to terminate their previous obligations to QFs. This regulatory shift combined with the Great Recession and volatile natural gas (NG) prices have continued to stagnate investments in CHP technologies [12].

In the past decade low natural gas prices in the U.S. spurred natural gas combined cycle (NGCC) investments, leading to a switch from coal to natural gas in many utilities in the U.S. A lot of fuel switching occurred in the industrial sector as well, but CHP development continued to be stagnant. According to a congressionally mandated 2015 U.S. Department of Energy (DOE) report, there are three main obstacles that stand in the way of improved industrial efficiency: (1) internal competition for capital, (2) a business model for electric utilities that fails to reward customer efficiency, and (3) internal informational barriers [13].

Across the world similar hurdles are faced, for example, European Union Cogeneration Directive sets down goals for “Good Quality” CHP to be part of delivered electricity [14,15]. However, these goals are yet to be reached. Recent initiatives of grid transformation are enabling and facilitating flexibility among Distributed Energy Resources (DER) to participate in the energy markets. Zhang (2016) looked at various financial incentives to promote CHP in different U.S. regions. Key aspects that made the CHP payback period shorter were operating CHP on a base load, rather than peak load shaving, and higher cost of electricity to cost of fuel ratio [16].

Today, there are over 82 GW of installed CHP capacity throughout the U.S., accounting for approximately 8% of total U.S. electricity generation and encompassing various industries, technologies, and fuel types. 10%, 23% and 64% of the total CHP capacity are installed in the commercial, refinery, and industrial sectors, respectively [17]. While investments in new CHP capacity have remained low for the past few years, certain drivers are occurring within the energy system that suggest a potential increase in the use of these technologies, including the stabilization and reduction of natural gas prices as well as growing federal and state policymaker support [12]. For example, a 2012 executive order mandated the investment of 40 GW of additional CHP capacity within the manufacturing sector by 2020 [18].

Perhaps the most uncertain factor that can affect future investments in CHP technologies in the industrial and commercial sectors is continuity of the existing utility model, air regulations, and potential GHG emissions reductions targets. Since 2015, U.S. EPA and the State Department have considered limiting GHG emissions specifically from Electric

Generating Units (EGUs) [19,20]; however no formal federal guidelines have been implemented. Many states and regions in the U.S. are adopting their own GHG reduction goals even in the absence of federal guidelines [21]. Many states recognize the value of DER and CHP to reduce emissions and fuel use to meet various reduction goals along with achieving economic savings [22].

A growing number of studies have identified and analyzed alternative pathways to achieve GHG reductions at different geographical, temporal scopes through use variety of modeling techniques, system boundary assumptions, level of detail in technology and end-use energy demand. Studies focusing on CHP systems and its role in meeting GHG reductions were applied at state(New York State [23], California [24]), country(United Kingdom [14,15,25], Italy [26], and China [27]), regional(Europe [28]) and global-scale [29–32].

One set of studies focused solely on analyzing CHP systems for district heating. Morvaj et al. (2017) designed a framework to optimize district heating potential of urban energy systems with an illustrative application. The study found that CHP use in commercial buildings was cost optimal when the grid was fossil based, and the renewable share of the grid highly influenced the level of end-use demand met by CHP. Higher penetration of renewables in the electric grid yielded more electrification in the end use sectors, reduced the reliance to CHP [33]. Similarly, Howard and Modi (2016) developed a model to identify optimum operation of and greenhouse gas (GHG) emissions benefits of combined heat and power (CHP) systems through applying it to various cities in the U.S. with disparate climate zones. They found that as the EGU’s CO2 emission rate decreased, GHG benefit from CHP lessened [34]. Another set of studies focused solely on challenges to implement CHP systems in the industrial sector [35] and how CHP can meet aggregate industrial demand [14]. One aspect missing in these studies is the simultaneous consideration of the implications of technology change and how it can meet demand in energy-intensive industries as well as commercial sectors within the energy system.

Another aspect not addressed in prior studies is consideration of any potential air quality and emissions trade-offs that may occur because of its increased use within the context of a changing energy system when CHP was included in the portfolio of technology options to reduce GHG emissions. NO_x, volatile organic compounds (VOCs), carbon monoxide (CO) and CH_4 emissions contribute to the formation of tropospheric ozone, which impacts air quality and yields adverse health outcomes. Similarly, PM_{10} emissions pose serious health risk including cardiovascular diseases and premature death in at-risk populations, and SO2 emissions contribute to aerosol and PM formation impacting air quality along with acid rain formation. In the U.S., the Clean Air Act [36] requires U.S. EPA to set national ambient air quality standards (NAAQS) for six criteria air pollutants (CAPs) namely ozone, PM, lead, CO, SO_2, NO_x. The law also requires U.S. EPA to periodically review the standards and revise them if appropriate to ensure that they provide the requisite amount of health and environmental protection and to update those standards as necessary. Furthermore, an exhaustive review of existing literature on air emissions and climate interactions by von Schneidemesser et al. (2015) demonstrates a strong linkage with air quality and climate change [37].

The purpose of this study is to analyze the dynamic role of CHP technologies in the context of the U.S. energy system evolution over the next decades under various carbon reduction scenarios and to quantify technology investments, trade-offs among air emissions (specifically the ones impacting air quality), and costs. To the best of our knowledge, existing literature focuses on only GHG emissions implications, operation issues, techno-economic analysis of single prime mover systems, analysis of existing technologies, and narrow focus on sectoral implications. The deployment of CHP systems in the context of future energy system transition and its potential role in meeting simultaneous emission reduction including GHG targets while meeting end-use demand and achieving air quality goals has not been analyzed. Various scenarios were developed that incorporate system-wide changes to the U.S. energy sector, including restrictions on CHP development, uncertainty in fuel prices, and carbon reductions of varying intensities. The scenarios were then analyzed using a bottom-up, technology-rich, publicly available model of the U.S. energy system.

2. Methods

In this study, we utilized an engineering-economic mixed-integer programming model (MARKet ALlocation (MARKAL)) that can model evolution of a region's energy system where all components related to extraction, production, conversion, delivery and use of energy is characterized at detail. The model then solves for the least-cost system-wide solution for meeting end-use energy service demands, given primary energy resources defined for a region [38]. The MARKAL framework developed in early 1970s is now maintained by ETSAP, and have multiple users across the world. The framework is based on a perfect foresight, given the assumptions about future costs of technologies. The U.S. EPA's Office of Research and Development has been maintaining a publicly available technology database representing the entire U.S. energy system in nine regions (i.e., Census divisions) for use within the MARKAL framework (hereafter referred to as the EPAUS9r database) [39]. The database includes supply curves covering cost and emissions associated with extraction and processing of primary energy such as coal, natural gas, crude oil, biomass feedstocks, and other non-biomass renewable resources, energy conversion technologies (e.g., refineries, EGUs), end-use demand technologies (e.g., process heaters to meet industrial demand, furnaces for space heating demand in buildings, light duty vehicles (LDV) for transportation demand), and end-use demands in residential, commercial, industrial and transportation sectors (e.g., vehicle miles of travel, lumens of lighting, value of shipments for industrial sector). The technologies are specified by their cost (e.g., capital, operation and maintenance (O&M)) and performance characteristics (capacity, efficiency, availability and emission rates for criteria air pollutants (CAP) and GHGs). In addition to these inputs, energy and environmental policies are input to database. MARKAL then solves for the lowest system-wide cost (i.e., total discounted investment, O&M, and fuel costs per technology) through its optimization routine, while satisfying energy balance and meeting constraints on policies and regulatory standards such as air quality regulations and vehicle efficiency standards and reports out the optimal mix of energy technologies and fuels. The reference case in the database is calibrated to the U.S. Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2014[40] where 2005 and 2010 represent the actual fuel use, demands, and electricity generation (based on operational EGU capacity in 2005

and 2010), and the period between 2015 and 2055 corresponds to the modeling years. One exception is for the industrial sector where end-use demand and levels of CHP use is calibrated to AEO 2015 [41]. Since the official release of the database, researchers around academia, nongovernmental organizations, and federal research laboratories apply and use the model for applications from analysis of policies to technology evaluations [42–48]. The main contribution of these studies as well as this study is the gathered insights on interactions of energy system components with economy, technological advancements, emissions and policy. EPAUS9r's availability to public led to development of many other country, region specific models. This study can be replicated for other locations given end-use demands in buildings, transportation and industry is available.

The EPAUS9r database includes all GHGs and CAPs associated with resource extraction and energy conversion technologies to meet the end-use service demand. The emission factors are derived from the GHGI and the National Emissions Inventory (NEI) [1,3]. In addition, major implemented air regulations that apply to the U.S. energy system are modeled in the EPAUS9r database.

This study utilized the EPAUS9r_2014_v1.5_cpp version of the EPAUS9r database to analyze energy system wide impacts of various CHP investment scenarios under technology and policy sensitivities with specific focus on the energy-intense manufacturing and commercial sectors [49]. The industrial sector in the EPAUS9r database covers the manufacturing sectors defined in North American Industry Classification System (NAICS) (code 31 – 33). The detailed coverage is summarized in Table A-1 of the Annex. The data on existing stock of CHP technologies in the industrial and commercial sectors are taken from U.S. DOE CHP Installation database [4,17]. The units are aggregated per technology and fuel type and represented for each energy intense industry and commercial sector per U.S. Census Region. CHP prime mover and system configurations modeled in the database is presented in Liu et al. (2014) [3]. The future techno-economic characteristics of the new advanced technologies are taken from [50].

In our analysis, we will report results from the 2015–2050 timeframe. The calibrated model run in the database is called the Base case. The model calculates the resultant electricity and fuel prices endogenously for modeling years. An explicit electricity price is neither an output of, or an input to the model. A user can either calculate the Levelized Cost of Electricity (LCOE) or utilize marginal (dual) prices for electricity (model output). In this study, we calculated the weightedaverage LCOE values, and report them as indexed to the Base case's LCOE in 2010 value. The costs are reported in 2005 dollars.

2.1. Scenario settings

Several scenarios are designed to analyze the economic and environmental implications of CHP development in the industrial and commercial sectors under various technology and energy price assumptions and alternative carbon reduction targets for a mid-range planning horizon (until 2050). The Base case refers to the reference scenario in the EPAUS9r database, which includes upper limits on CHP capacity expansion as reported by AEO 2015 and on which other scenarios are built [41].

The first attribute set for the scenarios has three variations reflecting technology choice assumptions: (1) CHP refers to the exclusion of any growth constraint on CHP capacity addition in both the industrial and commercial sectors. (2) NI (no investment) refers to no CHP capacity addition allowance for modeling years. (3) NR (no retirement) refers to delaying the retirement of existing CHP fleet until the end of the modeling horizon, which otherwise would retire after 30 years of operation in the industrial and commercial sectors.

The second attribute set for scenarios has four variations for carbon reductions: (1) EGU0 scenarios model 33% reduction of CO_2 emissions from the EGU sector by 2030. Emissions targets are kept constant after 2030. (2) EGU2 follows EGU0 reductions until 2030, then emissions are decreased by 2% annually until 2055. This scenario yields almost 60% carbon reduction in the EGU sector. (3) SYSE scenarios model 28% reduction of CO_2 equivalents (CO_2e) in the entire U.S. energy system by 2025 from 2005 levels. The emissions are then decreased by 1% annually starting in 2025 until 2055 [20]. The CO_2e includes CO_2 and CH_4 emissions where a global warming potential of 28 is applied to CH_4. (4) SYSC scenarios model similar reductions as in SYSE though only in CO_2 emissions. Both SYSE and SYSC scenarios yield almost 80% reduction in CO_2 emissions [30]. These levels represent the maximum reduction that can be achieved from the energy sector without the need to account for offsets such as land use changes or resulting in model infeasibilities.

The third attribute set for the scenarios reflect fuel price assumptions: (1) NG (natural gas price changes) refers to implications of natural gas prices simulated by an upward shift in the natural gas supply curve to yield doubling of the cost of extraction and processing of natural gas at each supply step.

Combinations of these attribute parameters yield our scenario set. For instance, CHP_SYSE_NG will include: (1) no limits on CHP capacity expansion, (2) a CO_2e limit on the entire energy system, and (3) the price of natural gas is doubled. A full description of the scenarios analyzed in this study is presented in Table A-2. Fig. 1 illustrates the CO_2 emissions reduction goals applied to scenarios.

3. Results

In 2010, the Base case reports 63 and 4 GW of CHP capacity installed in the industrial and commercial sectors, respectively. Over the period between 2015 and 2050, the Base case adds 11 GW (mostly NG Steam Turbine (ST)) and 17 GW (mostly NG Combustion Turbines (CT)) of CHP capacity in the industrial and commercial sectors, respectively. The fuel and technology mix for EGU and industrial sectors in the Base case shows continuation of trends beyond 2015 (Fig. 2). The Base case results in a total discounted cost of $52.4 Trillion (2005 Dollars) with 302,631 Million Metric Tons (MMT) of cumulative CO_2 emissions (Table 1). In the Base case, existing stock of industrial CHP capacity in 2005 and 2010 retires over time depending on age of the installation.

The majority of the capacity retirements occur in 2040, coinciding with the end of lifetime for most CHP capacity represented in the database. Beyond 2040, the EPAUS9r database includes a suite of new CHP technologies available for investments. Table A-3 presents CHP

capacity added over 2015–2050 for the industrial and commercial sectors per scenario. Table A-4 presents the prime mover choice in each end-use sector per scenario. The food and paper sectors add 2 GW of CHP capacity each by 2050, while the chemicals sector adds 4.5 GW CHP capacity by 2050. In the industrial sector, CHP provided electricity and steam throughout the modeling horizon with natural gas meeting one third of the industrial energy service demand by 2050. The use of coal in the industrial sector has been relatively low due to significant fuel switching to natural gas that occurred in the past decade. The Base case still shows steady use of metallurgical coal, liquid propane gas (LPG) and petroleum feedstocks, and by 2050, natural gas was contributing to 40% of the industrial fuel mix. Similarly, the EGU sector follows trends where coal use is continuous with steady increase in natural gas.

Fig. 3 shows the emission trends observed in the Base case. All reported emissions except for CH_4 either shows a constant rate or drastic decrease. National Ambient Air Quality Standards (NAAQS) are the main drivers for NO_x and SO_2 emission reductions [51]. In addition, post 2015 implementation of Tier 3 emission standards in the LDV transportation sector further reduces NO_x emissions. The increased access to domestic oil and gas resources due to techno-economic advancement of extraction techniques resulted in an insurgence of cheap oil and gas since early 2008 [47]. Availability of inexpensive oil and gas resources resulted in increase in more natural gas use in the energy sector. Therefore, we observed steady increase in CH_4 emissions from the resource extraction sector as more natural gas is extracted and utilized in the energy sector in the Base case.

Figs. 4 and 5 present fuel use in the EGU and industrial sectors across scenarios, respectively. The first two bars include the fuel use in 2010 and 2050 for the Base case. The following bars represent each analyzed scenario’s fuel use in 2050 in the EGU and industrial sectors, respectively. The bars are ordered in a descending manner with respect to total CO_2 emissions in 2050. Table 1 presents cumulative CO_2 emissions (2005–2050) and total discounted cost of the scenarios analyzed in this study.

The rest of this section is structured as follows: the results and analysis of EGU, SYS and NI scenarios in the context of fuel use in the EGU and industrial sectors and CHP technology trends, followed by the trends on the sectoral emissions. The results for NG and NR scenarios are presented in the context of sensitivities and can be found in Annex.

3.1. EGU scenarios

The EGU0 scenarios yield marginal reductions in CO_2 emissions, however significant reductions are observed in EGU2 and SYS scenarios (Table 1). Both Base_EGU0 and CHP_EGU0 achieve 3% reduction in cumulative CO_2 emissions at a total discounted cost similar to the Base case, whereas NI_EGU0 yields 4% reduction in cumulative CO_2 emissions with 0.2% increase in total discounted cost. Change in total discounted cost ranges from −0.4% to 3.1% with CO_2 reductions ranging from 3% to 6% in the EGU scenarios.

The major technology trends in EGU0 scenarios (except for NI_EGU0) when compared to the Base case are: (1) slight decrease in coal compensated by increase in wind and solar use

in EGU sector, (2) increase in CHP capacity in both industrial and commercial sectors, and (3) decrease in the amount of purchased electricity due to increased CHP capacity. Base_EGU0 results in decreased generation of electricity in the EGU sector, increased electricity generation from CHP and decreased CO_2 emissions with respect to the Base case (Fig. 4). Overall trends in EGU mix are homogenous across EGU scenarios, with 40–50% of electricity supplied by natural gas in 2050. CHP_EGU2 results in the lowest amount of utility based electricity generation, and the highest amount of electricity generation from CHP. Coal with carbon capture and sequestration (Coal-CCS) technology is utilized in CHP_EGU2 and NI_EGU2. Natural gas-CCS is utilized in NI_EGU2. Cumulative CO_2 emissions decrease 6% and 7% in CHP_EGU2 and NI_EGU2, respectively. NI_EGU2 disallows any new CHP investment, therefore as existing CHP capacity retires, industrial electricity demand is met by the EGU sector resulting in an increase in demand. To meet this increased demand as well as the CO_2 reduction target, the model builds more renewables coupled with natural gas and CCS. NI_EGU2 results in 0.4% increase in cost.

3.2. SYS scenarios

The SYS scenarios resulted in heavy decarbonization of the EGU sector with electrification of the end-use sectors such as buildings, transportation and industrial sectors, therefore increasing the demand for electricity. Capacity expansion is observed for nuclear, wind, and solar technologies. Natural gas-CCS has a market share along with coal-CCS by 2050 (see Fig. 4 last column). The new investments led to increases in LCOE, where LCOE of SYS scenarios in 2050 is on average triple the LCOE of the Base case. By 2050, almost one third of the demand for end-use services in the industrial sector was met by electricity from grid (Fig. 5). In SYS scenarios, the amount of industrial and commercial CHP investments decreased leading to more dependence on the EGU sector.

3.3. CHP technology trends in the industrial and commercial sectors

The CHP scenarios yield higher capacity investments for CHP systems (2–3 times more cumulative capacity addition, Table A-3) compared to the Base case as the growth of the technology is unbounded in those scenarios. EGU scenarios yielded more CHP capacity because the MARKAL optimization routine operates in perfect foresight, while searching for the best way to reduce EGU emissions over the planning period. Because the rest of the energy system was not constrained in the EGU scenarios, the model found it cheaper to produce some of the electricity outside the EGU sector. This resulted in a reduction in demand for electricity, and thus the model found a cheaper way to meet CO_2 limits without relying on a heavy transformation of the grid.

Natural gas micro-turbines (NG-MT) are the main prime movers utilized in CHP_EGU0 and CHP_EGU2 scenarios. SYS scenarios, however, result in lower CHP capacity expansion than EGU scenarios, where biomass fueled CHP technologies are the dominant choice. A total of 14.80 GW of CHP capacity using biomass is observed in CHP_SYSC. This is almost a quarter of the total CHP capacity added over the modeling horizon (Table A-3).

A sector or industry is generally conducive to CHP development if it has a high demand for steam and electricity. The chemicals, paper, food, and other manufacturing and non-

manufacturing industries are the main sectors utilizing CHP systems in descending order of capacity added. The nonmetallic mineral products and primary metals sectors are excluded from our analysis due to their low to non-existent steam requirements. The iron and steel sector within the metals industry has a significant amount of existing CHP capacity in the form of turbines using steam generated from waste gases from the integrated steel mills. The existing capacity is modeled in the EPAUS9r, however the decline of the mills in the U.S. is resulting in lower CHP investments in this industry [52].

The paper industry is the largest self-generator of electricity within the manufacturing sector, currently deriving 40% of its electricity needs from CHP technologies. The paper industry utilizes on-site generated biomass-based waste fuels (e.g., black liquor and hogged wood chips) to run their existing CHP systems [53]. In terms of economic growth outlook, certain sections of the pulp and paper industry, such as cardboard and tissue paper production is expected to grow, while other sections, such as newsprint, are expected to decline. These demand shifts for paper products in the U.S. and around the world have led the industry to be conservative on making investments in new technologies. The demands for goods have been stable, and the closing of facilities in the pulp and paper has industry resulted in less opportunity for growth and change. Our model inputs in the form of value of shipment projections reflect the slow growth [41]. However, even stagnant growth outlook, under various scenarios the pulp and paper industry still added on average 2 GW of CHP in the form of biomass steam turbines (ST).

According to AEO (2015), the food industry is expected to grow around 1.7% per annum [41]. This increase in demand for goods translates to higher demand for energy. The food industry relies heavily on steam for process heat and electricity for motors. This demand could be satisfied either through on-site CHP or purchased steam and electricity. Currently, the food industry has 8% of total CHP capacity in U.S. In our analysis, the highest CHP capacity addition in the food industry is observed in CHP_SYSC (11.42 GW), where biogas reciprocating internal combustion engines (RICE) and NG-MT are the main types of prime movers utilized. The EGU scenarios resulted in on average 9 GW of capacity addition over the Base case in the food industry (Table A-3). Similarly, the chemicals industry is expected to grow around 1.7% per annum in the U.S. Therefore demand for energy, especially in the form of steam, is expected to grow [41,54]. Currently, the chemicals industry has 28% of the total CHP capacity in the U.S. The CHP_EGU0 and CHP_EGU2 scenarios added almost 50% more CHP capacity in the form of NG-CT, whereas biomass-ST are the main prime mover choice in the SYS scenarios.

Prior studies focused heavily on energy efficiency within energy intense industries such as chemicals, pulp and paper, metals and so on. Until recently, it is evident with structural changes happening in the economy due to technology advancements and changes in demand for consumer products, the rest of the manufacturing sectors' energy demand is growing at a much faster pace than the energy intense industries. This creates a unique opportunity for CHP expansion to meet growing energy demand in these sectors. For example, almost 35% CHP capacity addition in the industrial sector is observed in the other manufacturing sectors in CHP_EGU2 (Table A-3), and the majority of this capacity is in the form of NG-MT (Table A-4).

Our analysis demonstrated that the commercial sector is conducive to CHP development (specifically institutional buildings) in the coming years, given that favorable changes within the U.S. energy sector take place [55]. At a minimum, over the 50-year planning period, our analysis shows 14 GW of additional CHP capacity in the commercial sector (Base case, Table A-4). Most of the capacity is in the form of NG-MT and some NG-CT (Table A-4). The resultant capacity levels were influenced by the technology availability, cost and fuel efficiency represented in the database, as well as the resultant relative LCOE across the EGU and SYS scenarios. Assuming the high demands for space heating, water heating, space cooling, and electricity, the use of CHP could increase fuel use efficiency and resiliency of both the industrial and commercial sectors [56]. However, further analysis is needed to ensure that CHP growth in the commercial sector does not result in unintended consequences. Keen et al. (2016) presents caveats to commercial CHP development. These include selecting the location and determining the heating and cooling requirements. Depending on how these factors stack up, the resultant system might yield inefficient utilization which in turn could lead to economic loss [57]. Both Brown (2017) and Keen et al. (2016) pointed out that the benefits of commercial co-generation facilities are highly dependent on ownership and operational differences [55,57]. Their analysis concluded that higher penetrations of CHP could reduce system cost, and have added benefits of reduced network congestions. Our analysis did not explicitly represent economic benefits of reduced network congestion, however these benefits could be realized highly in densely populated areas. EGU and SYS scenarios add on average 52 and 24 GW of CHP capacity in the commercial sector, respectively.

3.4. Emissions and cost implications

Overall, total CAPs and GHGs decrease over time in almost all scenarios. However, for some scenarios, sectoral emissions increase demonstrating trade-offs among air pollutants and GHG emission reduction targets. Total energy system, EGU, commercial and industrial sector CO_2, CH_4, NO_X and PM_{10} emissions are presented in Figs. A-1, A2, Figs. 6 and 7, respectively. Fig. A-3 presents PM_{10} emissions from the resource extraction and processing sector.

Table 1 summarizes the cost and the cumulative CO_2 emissions of each scenario. NI_SYSE results in the largest cumulative CO_2 reductions (23%) when compared to the Base case, however the cost-effectiveness of achieving these reductions is 70 kTonnes (kT) per million dollars spent. The most cost-effective scenario is CHP_EGU2, resulting in 460 kT of reduction per million dollars spent. It should be noted that CHP_EGU0 results in a 3% reduction in the cumulative CO_2 emissions at a total cost lower than the total discounted cost of the Base case. Overall, SYS scenarios achieve much lower cumulative CO_2 emissions, however the cost of achieving these were much higher as these scenarios result in a decarbonization of the EGU sector with significant reductions (Fig. A-1).

Almost 85% of CH_4 emissions from the energy system can be attributed to the resource sector specifically extraction and processing of fossil fuels, and follow natural gas use trends. In the scenarios where natural gas use is low, the resultant CH_4 emissions are low as well. CHP_SYSE results in the lowest CH_4 emissions due to minimal natural gas

consumption compared to other scenarios, whereas CHP_SYSC results in increased use of CHP in the industrial and commercial sectors leading to an increase in CH_4 emissions. In CHP_SYSC, CH_4 emissions from the industrial sector almost doubles (Fig. A-2).

NO_x emissions from the energy system reduced drastically from 2005 to 2015 with the implementation of Tier 3 standards and Corporate Average Fuel Economy (CAFE) rules in the transportation sector (Fig. 6a). The EGU and industrial sectors are the second and third largest contributors to overall NO_x emissions (Fig. 6b and d). SYS scenarios result in further reductions in NO_x where EGU scenarios follow emission trends observed in the Base case (Fig. 6a). In the EGU sector, CHP_EGU2 and CHP_SYSE result in lower NO_x emissions because CHP_EGU2 has the lowest amount of electricity generation, and CHP_SYSE has the lowest amount of fossil fuel use.

SYSE scenarios have the lowest NO_x and CH_4 emissions trends, indirectly resulting from achieving CO_2e reductions. The model could attain goals by reducing natural gas use within all sectors. Although natural gas is a clean burning fuel, its upstream extraction and production contributes to CH_4 and PM_{10} emissions. In addition, NG-RICE have high NO_x and CH_4 emissions rates due to operational limitations [58]. Because of this, the model switched from NG-RICE to biomassfueled CHP as the main prime-mover, and overall natural gas use in the EGU sector also decreased. NI_SYSC results in the lowest total NO_x emissions as wells as the lowest in the industrial and commercial sectors. No new investment in CHP and system level CO_2 reduction targets stimulates high electrification of end use sectors.

Similar trends are observed for PM_{10} emissions (Fig. 7). The majority of PM_{10} emissions in the energy system are emitted in the resource sector (Fig. A-3). Thus, total PM_{10} the level of natural gas and coal extracted from domestic resources. However, PM_{10} emissions tradeoffs among EGU (Fig. 7b), industrial (Fig. 7d) and commercial (Fig. 7c) sectors are dependent on the level of CHP capacity installed in each sector and fuel and technology choice for the prime mover. SYS scenarios result in PM_{10} reductions in the EGU and industrial sectors, however an increase in the commercial sector is observed due to increased use of biomass fueled CHP.

3.5. Tale of two scenarios: CHP_EGU2 and CHP_SYSC

CHP_EGU2 and CHP_SYSC result in the most divergent ways to meet the carbon reduction goals. Fig. 8 illustrates the EGU and the industrial sector fuel mix for the Base case, CHP_EGU2 and CHP_SYSC scenarios along with changes in CO_2 and NO_x emissions with respect to the Base case. EGU fuel mix in CHP_EGU2 resulted in slightly more wind and solar capacity along with NGCC and Coal-CCS use compared to the Base case. On the contrary, in CHP_SYSC, more than half of the electricity is produced from renewables and almost all fossil fuel capacity operates with CCS. Both scenarios generate more electricity from CHP than the Base case. More natural gas is consumed, and less electricity is purchased from the EGU to meet the industrial sector demand in CHP_EGU2, whereas industrial fuel consumption in CHP_SYSC is similar to the Base case’s. Except for 2050, most industrial end-use services are electrified. Even though some CHP is utilized, more electricity is purchased from EGU sector, and biomass-based CHP capacity is added during

those periods in CHP_SYSC (Table A-5 of Annex summarizes cumulative CHP capacity added by prime mover and fuel type for CHP_EGU2 and CHP_SYSC).

On one hand, CHP_EGU2 has the most CHP capacity expansion where the total new capacity addition by 2050 reached 86 GW (Table A-4). 54% of this expansion is seen in the commercial sector. In 2005, CHP_EGU2 has 105.4 GW of CHP capacity operating in the industrial and the commercial sectors (Table A-3). In the industrial sector, most of the CHP investments occurred in the rest of the manufacturing industries (17 GW), followed by chemicals (12.9 GW), then the food sector (9 GW) (Table A-3). On the other hand, CHP_SYSC has a total of 54 GW of CHP capacity addition by 2050, of which 20 GW was in the commercial sector. In the commercial sector, most of this capacity is in the form of NG-CT, whereas in the industrial sector, a variety of prime movers were selected with NG-MT being the dominant one (Table A-4). As for sub-sectoral use, almost equal capacity is observed among food, chemical and the rest of the manufacturing sectors (Table A-3).

CHP_EGU2 results in 284,751 MMT of cumulative CO_2 emissions whereas CHP_SYSC results in 238,193 MMT, corresponding to a 6% and 21% reduction from the Base case, respectively. CHP_EGU2 was the most cost-effective way to reduce CO_2 emissions at 460 kT of CO_2 reduced per million dollars spent (Table 1), whereas CHP_SYSC results in 80 kT of CO_2 reduction per million dollars spent.

NO_x emissions in 2050 in CHP_EGU2 increase by 0.6% with respect to the Base case while sectoral NO_x emissions show different trends. Compared to the Base case, the industrial and commercial NO_x emissions increase by 18% and 36%, respectively whereas EGU NO_x emissions decrease by almost 27%. The industrial and commercial NO_x emissions are driven by an increased use of NG-RICE and NG-CT in CHP_EGU2, though the overall NO_x emissions were still lower than in CHP_EGU0. In another instance, the use biomass in SYS scenarios led to increase in PM_{10} emissions. The increase in CAP emissions will adversely impact air quality, and lead to environmental and health damages. More natural gas use in the commercial and industrial sectors yielded increased NO_x emissions in CHP_EGU2. The use of NG-RICE in the commercial sector increase NO_x emissions in CHP_SYSC, whereas in the industrial sector the fuel of choice being biomass yields reductions in NO_x emissions.

The EGU sector trends observed in our analysis for SYS scenarios are along the lines of previous studies that looked at decarbonization pathways [28,30,31]. Most deep decarbonization pathways reported almost 80% reduction of CO_2 emissions by 2050. Those reductions were achieved through the high deployment of renewables, nuclear, biomass and CCS technologies in the EGU sector, along with electrification of end-use technologies. In addition to those insights, our study identified specific CHP technology and end-use energy demand pairs (Tables A-4 and A-5). For example, compared to Base case, a significant capacity addition of NG-MT was observed in the other manufacturing sector both in the CHP_EGU2 and CHP_SYSC scenarios. In the food industry, again NG-MT were utilized extensively in CHP_EGU2 scenario; however, levels of capacity addition were halved in CHP_SYSC. We also explored the sensitivities around natural gas price changes (NG). In general, fuel prices are one of the key drivers of technology change and fuel switching. Both CHP_EGU2_NG and CHP_SYSC_NG had almost no use of NG in the EGU sector, and half

of the generation in both scenarios was in the form of renewables (Fig. A-4). In terms of sector specific CHP technology selection, the NG-MT technology was highly sensitive to NG price changes in the EGU2 scenarios (Table A-6). We observed almost halving of added NG-MT CHP capacity for commercial sector when NG prices were doubled in CHP_EGU2_NG. The industrial sector CHP capacity additions did not change drastically with the NG price signals.

Our analysis demonstrated that near-term (until 2050) moderate reduction goals (e.g., limiting GHG emissions from EGU sector) resulted in more fossil based CHP capacity in the energy system, whereas aggressive reduction goals yielded mix use of both fossil and biomass CHP. As Fouquet (2016) states in his study “energy systems have a strong and long-lived path dependency” [59]. Capacity addition of a CHP plant or power plant into the energy system can last 20–30 years. A myopic look at near-term GHG reduction targets can lead to inferior technology investment decisions that create a technology lock-in. This can, in turn, hinder fast-turnaround of old and almost new infrastructure and deployment of clean energy sources to achieve longer-term aggressive mitigation targets.

4. Conclusions

CHP is promoted as an economical, energy-efficient option for reducing air emissions, mitigating GHG emissions, and reducing reliance on grid electricity hence enabling peak load shaving. Our study examined the viability and growth of CHP as a clean-technology alternative while considering how the broader energy system may transform under the influence of various technological and policy drivers that are specifically geared toward limiting GHG emissions including CO_2 and methane. We utilized a bottom-up technology model of the U.S. energy system to develop and analyze scenarios to determine the impacts of CHP development on both system-wide and sectoral GHG and air emissions. System level cumulative CO_2 emissions in over the modeling horizon decreased in the range of 3–23% compared to Base case’s CO_2 emissions levels. Scenarios that targeted system-wide GHG reductions resulted in 21–23% reduction of GHG emissions because the model found it optimal to decarbonize the electric sector and electrify all the end-use demand sectors, to a feasible extent. More CHP capacity was added when CO_2 limits were only in the electric sector, though the level of capacity addition fell when system level CO_2 limits were imposed. Most CHP capacity addition was in the form of natural gas microturbines utilized in the industrial and commercial sectors.

The vital contribution of our study is the detailed analysis of each energy-intensive industrial sector and commercial sector in the context of the larger energy system. Food, chemical, and non-manufacturing sectors are critical players in the industrial sector where most CHP capacity expansion was observed and yielded reductions in total system-wide CO_2 emissions. Scenarios limiting GHG reductions in the electric sector resulting in increased use of CHP in the industrial and the commercial sectors added an average of 50 GW of CHP capacity in the industrial sector. The utilization of CHP led to increase in both total and sectoral NO_x, PM_{10} and CH_4 emissions. This might suggest that technology drivers and policy decisions that only promote unconstrained CHP growth and CO_2 standards for the electric sector will have slightly negative impacts on air quality. CO_2 emissions targets on

the U.S. energy system still allowed for investments in CHP technologies (40% less compared to scenarios limiting electric sector CO2 emissions) and resulted in reduced total system-wide NO_x, and PM_{10} emissions. However, in these scenarios, use of biomass in the CHP technologies resulted in increased PM_{10} emissions in the commercial sector.

Currently, utilities and consumers are encouraged to move and have already been moving towards decentralized market structures to incorporate distributed small generators (behind-the-meter generation) into the base load in a cheap and effective way. When considering CHP technologies as options for reducing CO_2 emissions, it is important to consider any potential air quality and emissions trade-offs that may occur because of its increased use within the context of a changing energy system. As state and local municipalities move towards more DER and CHP, market mechanisms could be utilized to promote penetration of cleaner technologies to avoid unintended consequences. Our analysis found that addition of distributed energy, especially in the form of fossil energy, does not necessarily yield simultaneous reductions in air emissions. On the contrary, some air pollutant emissions increased in certain end-use sectors. In another instance, biomass-based technologies might have a low carbon footprint, however, depending on the prime-mover choice, use of it could lead to increased PM_{10} emissions and thus can have adverse health outcomes and contribute to ozone formation impacting air quality. Thus, technology and fuel choice becomes critical in promoting DER in certain areas while trying to reduce GHG emissions.

Along with emission reduction benefits, DER could have additional benefits such as grid resiliency, peak load shaving, etc. A “tiered approach” to regulatory schemes is needed as targeting individual sectors (e.g., EGU targets) as silos might lead to leakage in air pollutant emissions in other end-use sectors (e.g., residential or manufacturing sectors). Future analyses could explore the dynamics of alternative renewable DER options. We conducted a sensitivity analysis on the capital cost of alternative DERs such as fuel cells. The current price and efficiency points for those technologies are high, and our analysis did not show any capacity expansion on those technologies. Future analyses could also explore the price dynamics of these technologies.

In conclusion, sectoral carbon targets, coupled with incentives to decentralize end-use demand technologies might result in low CO_2 emissions while limiting fossil fuel CHP development and thus avoid any increase in air pollutant emissions. Our analysis is not intended to be predictive, but rather represent several possible pathways that the U.S. energy system might take over the next several decades for nearterm GHG reduction targets. Any infrastructure expansion into the energy system (e.g., new CHP plant) can last 20–30 years. A myopic look at near-term GHG reduction targets can lead to inferior technology investment decisions that create a technology lock-in. This can, in turn, hinder fast turnaround of existing infrastructure and deployment of clean energy sources needed to achieve longer-term aggressive mitigation targets. Our results are informative for investigating relationships between energy use, emissions, and technological progress. The conclusion can be transferable to other geographical areas given the energy system characteristics aligns with the set-up of our analysis.

Supplementary Material

Refer to Web version on PubMed Central for supplementary material.

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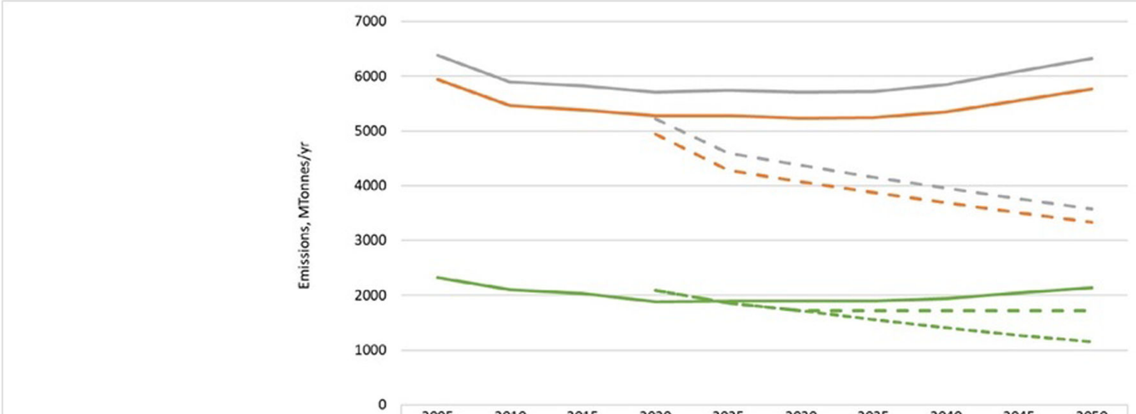
Highlights

- Assess economic and environmental impacts of industrial and commercial CHP expansion.
- Distributed energy resources contribute to resilience and provide peak load shaving.
- CHP market penetration influences marginal prices hence EGU capacity expansion.
- Sectoral carbon targets may lead to emissions leakage in other end-use sectors.
- A tiered regulatory approach is needed to couple renewable energy and DER expansion.



	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
System-wide CO2 emissions in the Base Case	5941	5469	5382	5277	5279	5236	5241	5347	5563	5770
System-wide CO2e emissions in the Base Case	6376	5896	5819	5714	5739	5707	5720	5844	6090	6328
CO2 emissions in the EGU sector in the Base Case	2328	2099	2037	1886	1893	1897	1890	1940	2048	2132
EGU0 scenario setting: CO2 limits on the EGU sector				2091	1858	1719	1719	1719	1719	1719
EGU2 scenario setting: CO2 limits on the EGU sector				2091	1858	1719	1554	1404	1269	1148
SYSC Scenario setting: system-wide CO2 limits				4942	4287	4077	3877	3687	3506	3334
SYSE Scenario setting: system-wide CO2e limits				5223	4599	4374	4160	3956	3762	3578

Fig. 1.

Resultant CO_2 emissions for the Base Case and CO_2 reduction targets for scenarios.

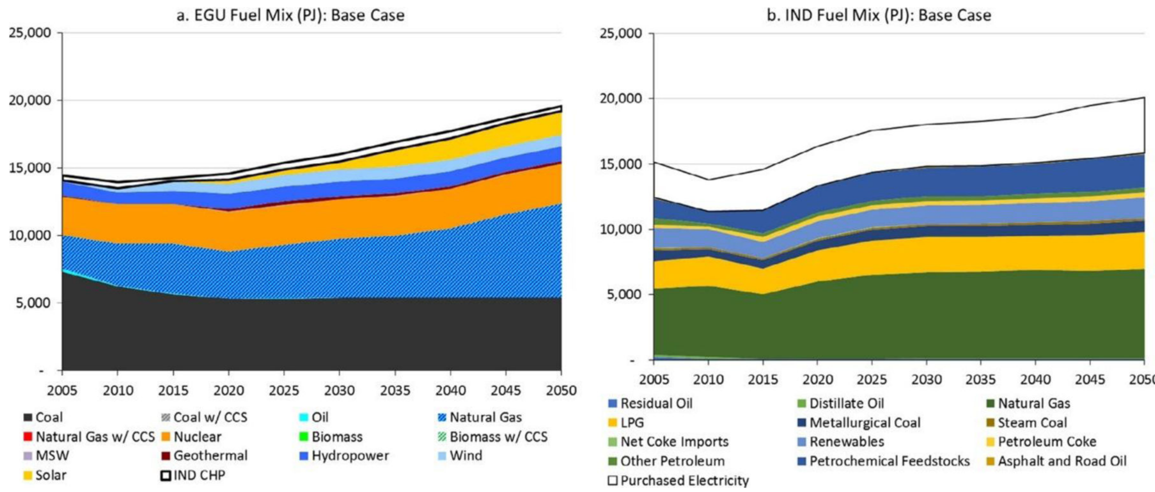


Fig. 2.
Base Case: Fuel Mix for (a) EGU and (b) Industrial Sectors.

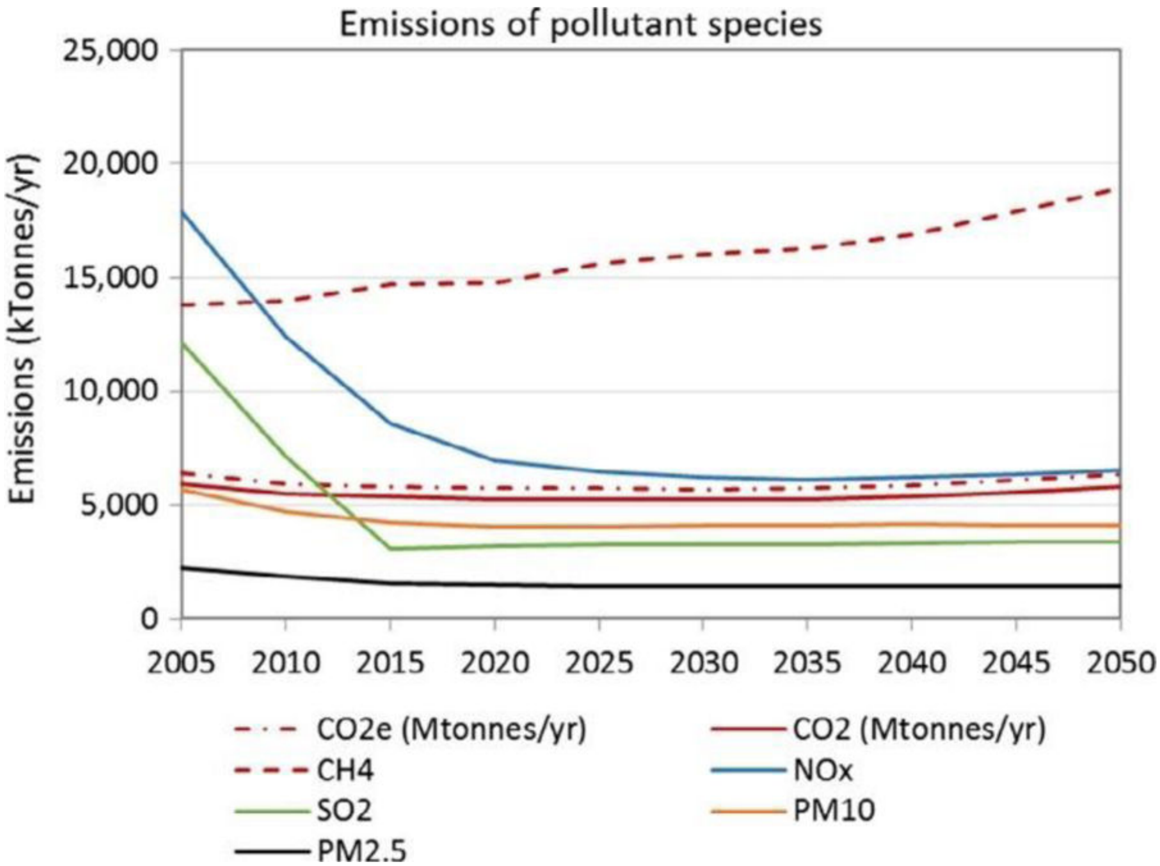
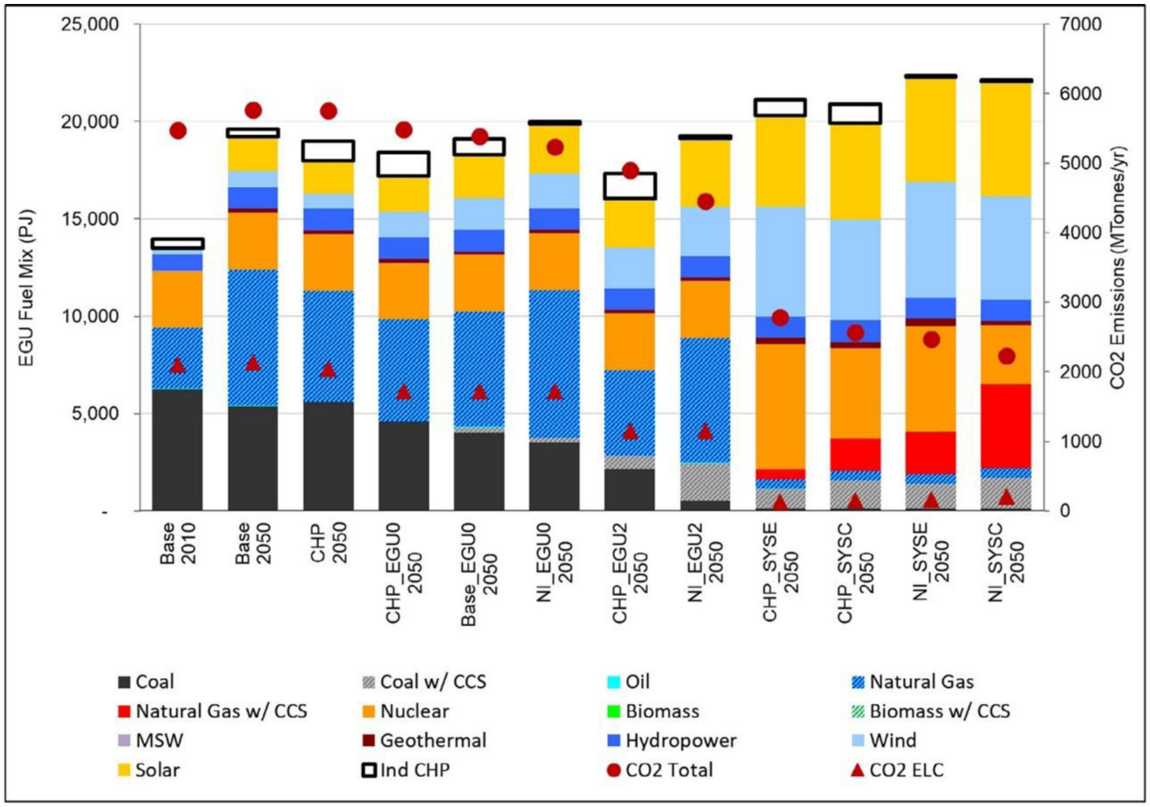


Fig. 3.

Base Case: Emission Trends across the Modeling Horizon (2005–2050).



	Base 2010	Base 2050	CHP 2050	CHP_EGU0 2050	Base_EGU0 2050	NI_EGU0 2050	CHP_EGU2 2050	NI_EGU2 2050	CHP_SYSE 2050	CHP_SYSC 2050	NI_SYSE 2050	NI_SYSC 2050
LCOE Index	1.00	2.52	2.44	2.92	3.08	3.33	3.29	3.72	4.80	4.73	5.04	4.78

Fig. 4.

EGU Fuel Mix, System-wide CO_2 and EGU CO Emissions Levels at 2010 and 2050 (A comparison with respect to levels in 2010 and 2050 in the Base case scenario are included in the first two bars).

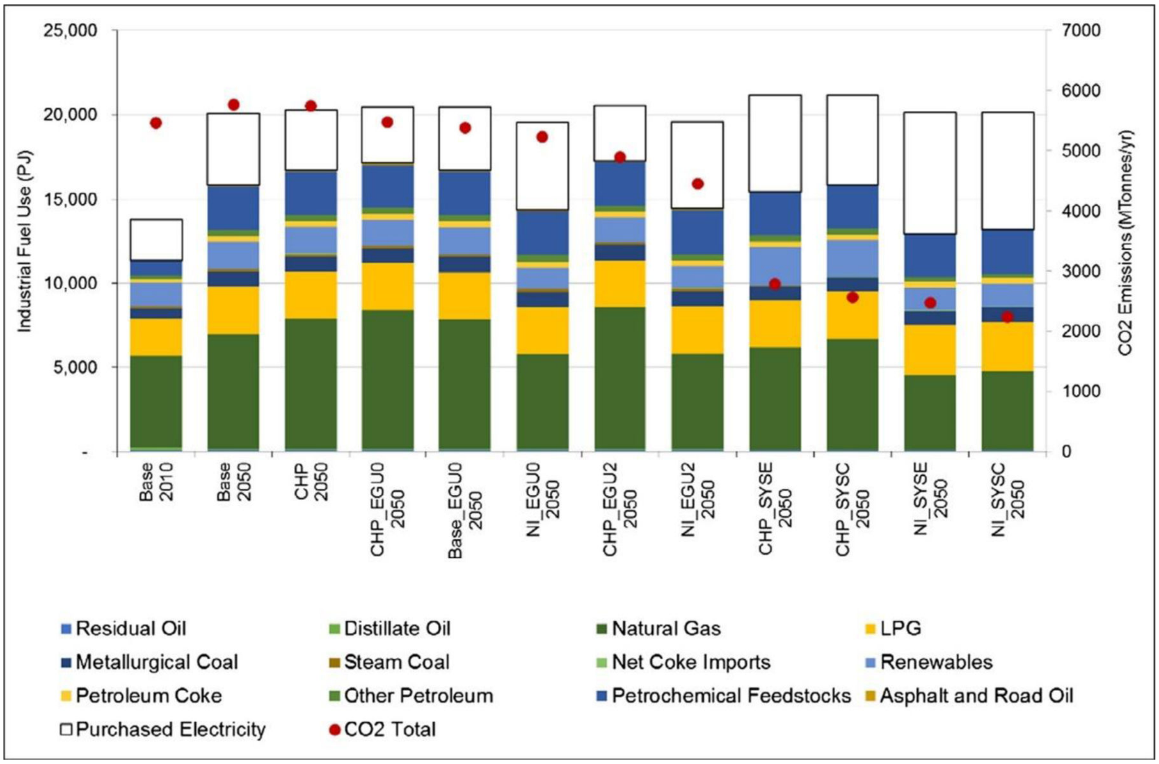


Fig. 5.

Industrial Fuel Use and System-wide CO Emissions Levels at 2010 and 2050 (A comparison with respect to levels in 2010 and 2050 in the Base case scenario were included in the first two bars.)

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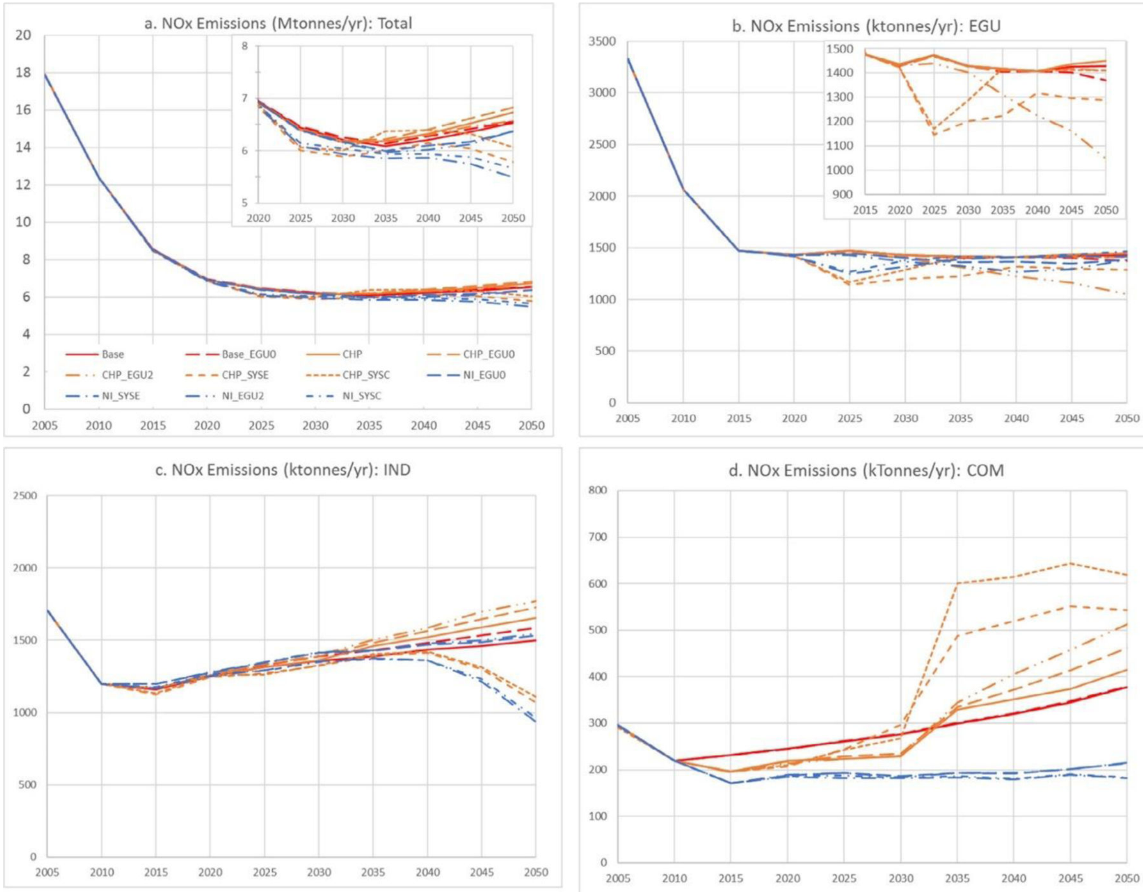

Fig. 6.

NO_x Emissions: (a) Total energy system; (b) EGU sector; (c) industrial sector; and (d) commercial sector.

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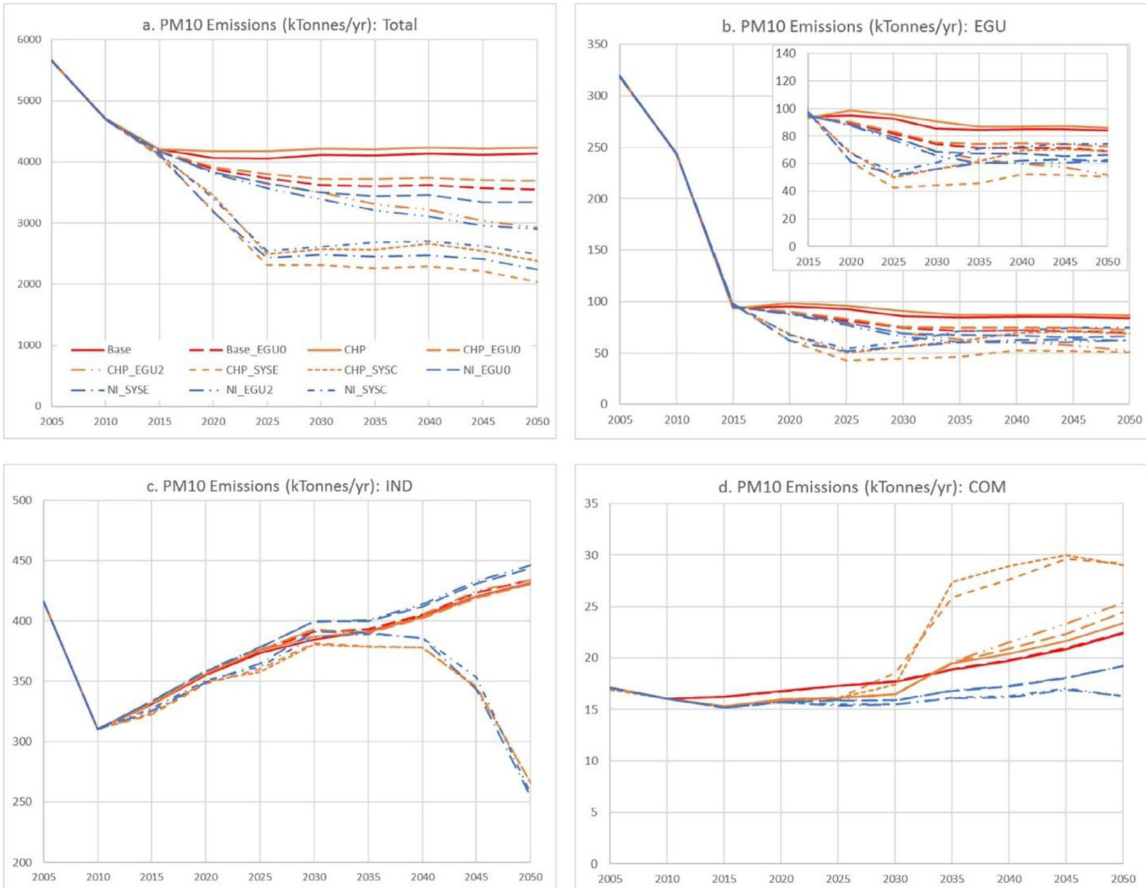

Fig. 7.

PM_{10} Emissions: (a) Total energy system; (b) EGU sector; (c) industrial sector; and (d) commercial sector.

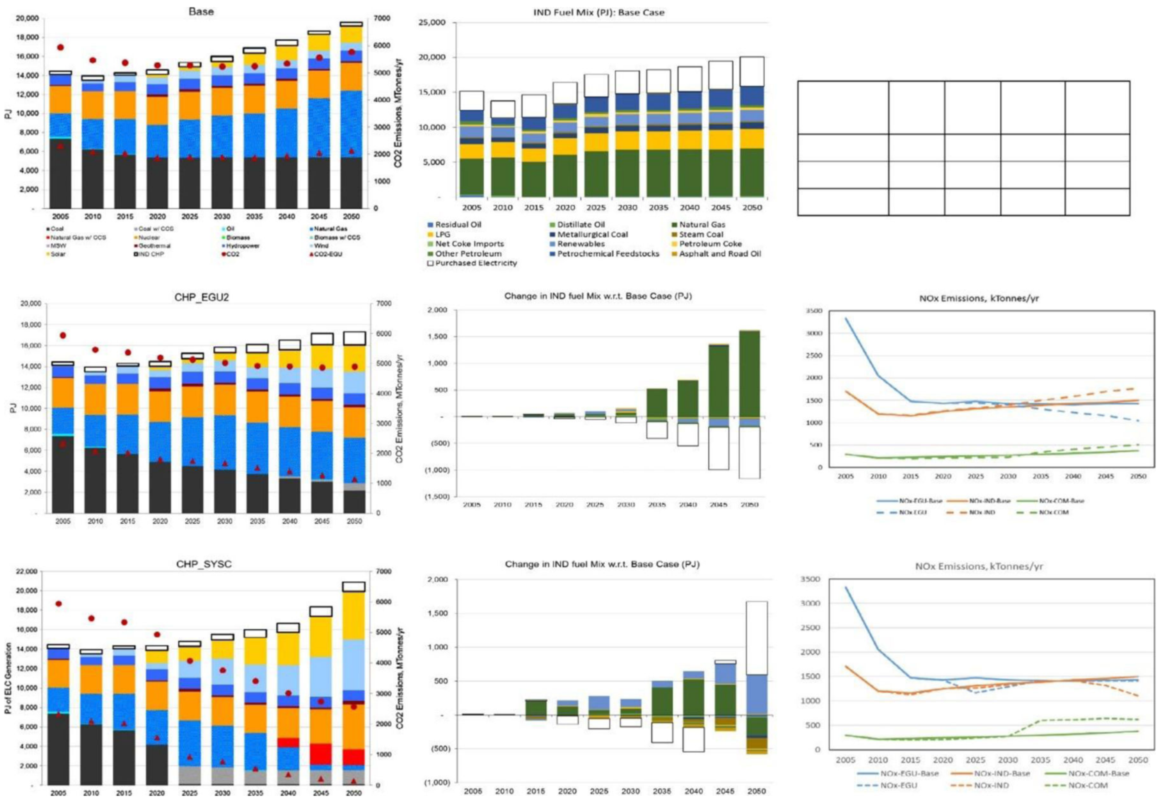

Fig. 8.

Comparison of the Base Case with Two Distinct Scenarios: CHP_EGU2 and CHP_SYSC.

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Table 1.

Total Cumulative CO_2 Emissions in Million Metric Tons (MMT) and Total Discounted Cost in Trillion 2005$ of Scenarios (ordered in ascending total cost after the Base case).

	Cum. CO_2, MMT	Δ CO_2 w.r.t Base Case	Total cost, $ Trillion	Δ cost w.r.t Base Case	ΔCO_2 per ΔCost
Base	302,631		$ 52.41		
Base_EGU0_NR	293,668	−3%	$ 52.18	−0.4%	0.04
CHP_EGU0	294,721	−3%	$ 52.39	0.0%	0.38
CHP	302,885	0%	$ 52.41	0.0%	0.08
CHP_EGU2	284,751	−6%	$ 52.44	0.1%	−0.46
Base_EGU0	293,002	−3%	$ 52.44	0.1%	−0.27
NI_EGU0	291,258	−4%	$ 52.52	0.2%	−0.10
NI_EGU2	280,512	−7%	$ 52.60	0.4%	−0.11
CHP_SYSC	238,193	−21%	$ 53.20	1.5%	−0.08
NI_SYSC	238,241	−21%	$ 53.26	1.6%	−0.08
CHP_SYSE	234,736	−22%	$ 53.37	1.8%	−0.07
NI_SYSE	234,041	−23%	$ 53.45	2.0%	−0.07
Price sensitivities Base_EGU0_NG	285,202	−6%	$ 53.81	2.7%	−0.01
CHP_NG	288,718	−5%	$ 54.00	3.0%	−0.01
CHP_EGU0_NG	285,856	−6%	$ 54.01	3.1%	−0.01
CHP_EGU2_NG	278,101	−8%	$ 54.07	3.2%	−0.01
CHP_SYSC_NG	237,976	−21%	$ 54.69	4.4%	−0.03
CHP_SYSE_NG	235,819	−22%	$ 54.77	4.5%	−0.03