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Revision 1
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Generation and Use of Thermal Energy in the U.S. Industrial Sector and Opportunities to Reduce its Carbon Emissions

Colin McMillan[1], Richard Boardman[2],
Michael McKellar[2], Piyush Sabharwall[2],
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[1] National Renewable Energy Laboratory
[2] Idaho National Laboratory

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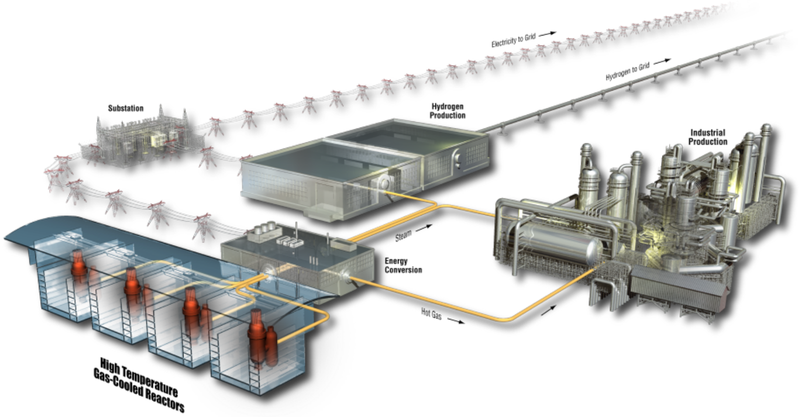

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Idaho National Laboratory
Idaho Falls, Idaho 83415

http://www.inl.gov

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Foreword

The U.S. economy is constantly evolving, especially in regard to how energy is generated and used in the electricity, buildings, industrial, and transportation sectors. These changes are being driven by economics and by environmental and energy security concerns. The electricity-sector market share of natural gas and variable-generation renewables, such as wind and solar photovoltaics (PV), continues to grow. The buildings sector is evolving to meet efficiency standards, the transportation sector is evolving to meet efficiency and renewable fuels standards, and the industrial sector is evolving to reduce emissions through efficiency improvements, advanced combined heat and power (CHP), and increased energy storage (DOE 2015a). These drivers provide investment and utilization strategies for innovative energy generation and delivery assets.

Nuclear and renewable energy sources are important to consider in the U.S. economy's evolution because both are clean, non-carbon-emitting energy sources. The Idaho National Laboratory (INL) and the National Renewable Energy Laboratory (NREL) are jointly investigating potential synergies between nuclear and renewable energy technologies. A series of workshops since 2011 have brought together experts and stakeholders in both areas to identify collaboration opportunities and to develop research plans to analyze and evaluate the costs and benefits and technical development needs of nuclear renewable energy beyond the electrical power market. Workshop participants identified nuclear-renewable hybrid energy systems (N-R HESs) as one of the potential opportunities and recommended investigating whether N-R HESs could both generate dispatchable electricity without carbon emissions and provide clean energy to industrial processes. They also recommended analyzing the potential for N-R HESs to provide dispatchable capacity to the grid and to investigate whether real inertia provided by thermal power cycles within N-R HESs provides value to the grid.

Several categories of N-R HESs have been identified. Tightly coupled N-R HESs are co-located, directly integrated, and co-controlled behind the grid (i.e., they have a single connection to the grid). Thermally coupled N-R HESs have an integrated thermal connection and are co-controlled but may have multiple electrical connections to the grid and subsystems may not be co-located. Loosely coupled, electricity-only N-R HESs only have electrical interfaces and subsystems that can be located separately with multiple connections to the grid, but they are co-controlled so a single management entity dispatches the energy and services they provide to the grid.

This report is one in a series of reports that INL and NREL are publishing that address the technical and economic aspects of N-R HESs. Previous reports focused on tightly coupled N-R HESs. Two N-R HES scenarios were initially analyzed by INL to evaluate their dynamic performance characteristics (Garcia 2015). Subsequent analysis conducted by NREL for the Joint Institute for Strategic Energy Analysis (JISEA) assessed the optimal economic configurations and operation of similar N-R HESs (Ruth et al. 2016a). These scenarios are based on a future condition when a significant fraction of power generation is being produced by wind or PV, and a new small modular nuclear power plant that apportions heat between power production and a heat user is added to the grid. The first scenario involves the production of methanol from natural gas with nuclear energy shifting between methanol production and power production that ramps up and down, corresponding to wind power generation and grid demand dynamics. The second scenario involves operation of a brackish water desalination plant when the combination of nuclear and solar power generation exceeds grid demand.

The joint analyses conducted by INL and by NREL for JISEA found that nuclear plants can effectively modulate heat between power production and heat use by an industrial consumer. The analyses by NREL indicate the optimal financial performance occurs when the nuclear reactor is mainly supplying heat to industry. The nuclear reactor may switch to power generation if capacity payments for power production are adequate. These outcomes demonstrate that nuclear and renewable energy can fulfill power generation and thermal duties of the grid and industrial heat users in a complementary manner, but hybridization will depend on the future cost of natural gas power production and clean energy investment and production incentives.

This report quantifies greenhouse gas (GHG) emissions from the industrial sector and identifies opportunities for non-GHG-emitting thermal energy sources to replace the most significant GHG-emitting U.S. industries based on targeted, process-level analysis of industrial heat requirements. The intent is to provide a basis for projecting opportunities for clean energy use. This provides a prospectus for small modular nuclear reactors (including N-R HES), solar industrial process heat, and geothermal energy.

Acknowledgments

The authors thank the Office for Advanced Reactor Technology within the U.S. Department of Energy's (DOE's) Office of Nuclear Energy (NE) and the Office of Strategic Programs within DOE's office of Energy Efficiency and Renewable Energy (EERE) for their support of this analysis and report. The authors also thank those who originated and developed the concept of nuclear-renewable hybrid energy systems including Charles Forsberg of the Massachusetts Institute of Technology (MIT); Humberto Garcia and Steven Aumeier of Idaho National Laboratory (INL); and Owen Zinaman of NREL. We acknowledge and thank the following individuals for their reviews and comments: Steve Capanna, Ookie Ma, Paul Spitsen, and Brian Walker (EERE); Carl Sink (NE); John Agan (DOE's Office of Energy Policy and Systems Analysis); Carl Stoots (INL); Doug Arent (Joint Institute for Strategic Energy Analysis [JISEA]); and Gian Porro, Parthiv Kurup, and Kevin McCabe (National Renewable Energy Laboratory [NREL]).

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Acronyms and Abbreviations

bpd	barrels per day
Btu	British thermal unit
CBP	County Business Patterns
CEMI	Clean Energy Manufacturing Initiative (U.S. Department of Energy)
CH_4	methane
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
COP21	Conference of the Parties
CSP	concentrating solar power
DOE	U.S. Department of Energy
EERE	Office of Energy Efficiency and Renewable Energy
EGS	enhanced geothermal systems
EIA	U.S. Energy Information Administration
EJ	exajoules (1 EJ = 10^{18} J)
EP	energy park
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FCC	Federal Communications Commission
FDA	Food and Drug Administration
FHR	Fluoride-salt high temperature reactor
FIRES	Firebrick Resistance-Heated Energy Storage
FORGE	Frontier Observatory for Research in Geothermal Energy
GHG	greenhouse gas
GHGRP	EPA Greenhouse Gas Reporting Program
GJ	gigajoules (1 GJ = 10^9 J)
HES	hybrid energy system
HHV	higher heating value
HRSG	heat recovery/steam generation
HTGR	high-temperature gas reactor
HVAC	heating, ventilating, and air conditioning
INL	Idaho National Laboratory
J	joule
JISEA	Joint Institute for Strategic Energy Analysis
LINE	Leadership in Nuclear Energy
LWR	light-water reactor
ME	multi-energy
MECS	Manufacturing Energy Consumption Survey
MHz	megahertz
MMBtu	million Btu (1 MMBtu = 10^6 Btu)
$MMTCO_2e$	million metric tons carbon dioxide-equivalent
MPa	megapascal
$MTCO_2e$	metric tons carbon dioxide-equivalent
MW	megawatt

MWe	megawatt-electric
MWh	megawatt-hour
MW_t	megawatt-thermal
NA	not applicable
NAICS	North American Industrial Classification System
NGNP	Next-Generation Nuclear Plant [Program]
NNMI	National Network for Manufacturing Innovation
NO_x	nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
N-R HES	nuclear-renewable hybrid energy system
PE	polyethylene
PEM	proton-exchange membrane
PET	polyethylene terephthalate
PJ	petajoules (1 PJ = 10^{15} J)
PRA	probability risk assessment
PV	photovoltaic
PWR	pressurized-water reactor
Quads	quadrillion Btu (1 quad = 10^{15} Btu)
RTO	regenerative thermal oxidizer
SEDS	State Energy Data System
SEGS	Solar Electric Generating Station
SIPH	solar industrial process heat
SMR	small modular reactor
TBtu	trillion Btu (1 TBtu = 10^{12} Btu)
T-H	temperature-enthalpy
TJ	terajoules (1 TJ = 10^{12} J)
USGS	U.S. Geological Survey

Executive Summary

The industrial sector was the third-largest source of direct[1] U.S. greenhouse gas (GHG) emissions in 2014 behind electricity generation and transportation and accounted for roughly 20% of total emissions (EPA 2016). The Energy Information Administration (EIA) projects that total U.S. energy consumption will grow to about 108 exajoules (1 EJ = 10^{18} J) or 102 quads (1 quad = 10^{15} British thermal units) in 2025, with nearly all of the growth coming from the industrial sector (DOE 2015b). Energy consumption in the industrial sector is forecast to increase to 39.5 EJ (37.4 quads)—a 22% increase, exceeding 36% of total energy consumption in the United States. Therefore, it is imperative that industrial GHG emissions be considered in any strategy intent on achieving deep decarbonization of the energy sector as a whole.

It is important to note that unlike the transportation sector and electrical grid, energy use by industry often involves direct conversion of primary energy sources to thermal and electrical energy at the point of consumption. About 52% of U.S. industrial direct GHG emissions are the result of fuel combustion (EPA 2016) to produce hot gases and steam for process heating, process reactions, and process evaporation, concentration, and drying. The heterogeneity and variations in scale of U.S. industry and the complexity of modern industrial firms' global supply chains are among the sector's unique challenges to minimizing its GHG emissions. A combination of varied strategies—such as energy efficiency, material efficiency, and switching to low-carbon fuels—can help reduce absolute industrial GHG emissions (Fischedick et al. 2014a).

This report provides a complement to process-efficiency improvement to consider how clean energy delivery and use by industry could reduce GHG emissions. Specifically, it considers the possibility of replacing fossil-fuel combustion in industry with nuclear (specifically small modular reactors [SMRs]), solar thermal (referred to herein as solar industrial process heat [SIPH]), and geothermal energy sources. The possibility of applying electrical heating and greater use of hydrogen is also considered, although these opportunities are not discussed in as much detail.

Development of effective GHG mitigation strategies requires a detailed understanding of the types of industries and their energy-use patterns and associated emissions. This has recently been made possible by the U.S. Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program (GHGRP). Under the Mandatory Reporting of Greenhouse Gases Rule, facilities with annual direct emissions greater than or equal to 25,000 metric tons carbon dioxide-equivalent (MTCO_2e) are required to report to the EPA (*Part 98—Mandatory Greenhouse Gas Reporting* 2016). Over 8,000 facilities representing nine industry sectors[2] reported direct emissions of 3,200 million MTCO_2e (MMTCO_2e), or nearly half of U.S. total GHG emissions, for the 2014 reporting year (U.S. Environmental Protection Agency 2016).

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[1] Direct emissions are the result of activities that occur on-site at a facility. See https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions#industry.

[2] The EPA identifies these nine industry sectors as power plants, petroleum and natural gas systems, refineries, chemicals, waste, metals, minerals, pulp and paper, and "other." https://www.epa.gov/ghgreporting/ghgrp-2014-reported-data.

In this study, we used the GHGRP-reported emissions data and EPA GHG emissions factors to calculate facility-level thermal energy demands. Fourteen key industries with the highest annual GHG emissions were selected for assessment of their emission characteristics and thermal heat duties. Within these industries, representative plants were selected to determine how clean heat from SMRs, SIPH, and geothermal sources could be used.

The GHGRP data allowed further disaggregation of thermal energy use, enabling analysis by fuel type, combustion-unit type, and end use for the 14 industries. The target industries are listed in declining order of GHG emissions in Table ES-1, along with potential alternative heat supplies identified in this report. Note that this table represents an initial selection based only on matching process-heat temperature and does not consider all technical and non-technical characteristics of each alternative heat supply. Additional technical characteristics and considerations are provided in the main body of the report.

The common feature of the target industries is that they convert raw materials into energy services by means of physical and chemical changes. These changes generally require thermal energy to affect solids and liquids heat-up, melting, and evaporation and to heat up reactants to initiate molecular bond-breaking and to sustain the propagation of chemical reactions. Heat demands range from low-temperature steam (50°C, 0.7 megapascal [MPa]) for steeping in corn wet-milling to high-temperature operations up to 2,200°C for electric arc furnaces. The scale of heat demand for the average facility ranges from 0.016 TJ per day (15 MMBtu/day; or 0.2 MW_t) for electrochemical production of 1,330 tonnes per day chlorine to 26 TJ/day (25,000 MMBtu; or 300 MW_t) for 5,273 tonnes per day of potash, soda, or borate mining and processing.

Several technical challenges and opportunities to application of clean energy sources for industrial heat users were identified and are discussed in this report, including:

- Quality of heat required by the user (or temperature of the working fluid)
- Industry process heat-transfer modes
- Scale of heat source versus heat user demand, which may be mitigated by selecting the appropriate source or by industrial clustering (viz., an energy park)
- Transport requirements between the heat source and industrial process-unit operations, which involves distance and the materials needed for that transport
- Thermal energy storage needs and options
- Hybrid heat/electricity production
- Electrification of heating processes
- Hydrogen production and use as an intermediate energy source.

Table ES-1. Summary of Potential Alternative Heat Supplies by Target Industry (TJ = terajoule = 10^{12} J)

Target Industry	Number of GHGRP-Reporting Plants in 2014	Average Size of Plant (Production Rate)	Reported CO_2 Emissions ($MMTCO_2e$)	Fraction of Industrial-Sector GHG Emissions (%)*	Industry Process-Heat Type/Purpose	Average Plant Heat Use in TJ/day (MMBtu/day)	Process-Heat Temperature (ºC)	Potential Alternative Heat Supply**
Petroleum Refineries	141		124	8	Combustion gases/atmospheric crude fractionator and heavy naphtha reformer	8.23 (7,800)	600	SIPH, SMR (HTGR)
Gasoline		33,828 bpd						
Diesel		12,747 bpd						
Kerosene		6,755 bpd						
Iron and Steel Mills	115	603	51	3	Combustion gases/coke production	2.42 (2,290)	1,100	Hydrogen reducing agent
					Combustion gases/steel production		1,700	***
					Electricity/steel production		2,200	***
Paper Mills	116	1,723	32	2	Steam/stock preparation	21.1 (20,000)	150	***
					Steam/drying		177	***
Paperboard Mills	73	4,427	24	1.5	Steam/stock preparation		150	***
					Steam/drying		177	***
Pulp Mills	30	474	12	0.7	Combustion gases/electricity production	0.67 (640)	800	***
					Steam/wood digesting, bleaching, evaporation, chemical preparation	1.15 (1,090)	200	***

Target Industry	Number of GHGRP-Reporting Plants in 2014	Average Size of Plant (Production Rate)	Reported CO$_2$ Emissions (MMTCO$_2$e)	Fraction of Industrial-Sector GHG Emissions (%)*	Industry Process-Heat Type/Purpose	Average Plant Heat Use in TJ/day (MMBtu/day)	Process-Heat Temperature (ºC)	Potential Alternative Heat Supply**
					Steam/evaporation, chemical preparation	2.56 (2,430)	150	***
All Other Basic Chemical Manufacturing	85	2,702	21	1.3	Combustion gases/primary reformer; steam/methanol distillation	12.9 (12,200)	900	SMR, SIPH
Ethyl Alcohol Manufacturing	168	63.7	18	1.1	Combustion gases for steam/byproduct drying (corn dry mills)/pretreatment and conditioning (lignocellulosic processes)	1.76 (1,670)	266	SMR, SIPH
					Steam/distillation		233	SMR, SIPH
					Steam/electricity production		454	SMR, SIPH
Plastics Material and Resin Manufacturing	72	1,591	17	1	Steam/distillation	10.6 (10,061)	291	SMR, SIPH
Petrochemical Manufacturing	35	2,665	16	1	Combustion gases/cracking furnace	2.37 (2,250)	875	***
Alkalies and Chlorine Manufacturing	11		13	0.8	Steam/drying	4.26 (4,040)	177	SMR, SIPH
Chlorine		1,330						
Sodium Hydroxide		1,162						

Target Industry	Number of GHGRP-Reporting Plants in 2014	Average Size of Plant (Production Rate)	Reported CO_2 Emissions ($MMTCO_2e$)	Fraction of Industrial-Sector GHG Emissions (%)*	Industry Process-Heat Type/Purpose	Average Plant Heat Use in TJ/day (MMBtu/day)	Process-Heat Temperature (ºC)	Potential Alternative Heat Supply**
Nitrogenous Fertilizer Manufacturing	30		8	0.5	Combustion gases/primary steam reforming	7.03 (6,660)	850	SMR,SIPH
Wet Corn Milling	24		18	1.1	Steam/steeping	8.06 (7,640)	50	SMR, SIPH, geothermal
Starch		1,461			Steam/drying		177	SMR, SIPH
Corn Gluten Feed		593						
Corn Gluten Meal		137						
Corn Oil		92						
Lime and Cement	49		10	0.6	Combustion gases/heating kiln	12.45 (11,800)	1,200–1,500	***
Lime		507						
Cement		2,000						
Potash, Soda, and Borate Mining	11	5,273	6	0.4	Steam/calciner, crystallizer, and dryer	26 (25,000)	300	SMR, SIPH

* Includes CO_2 from biomass combustion

** SMR temperatures up to 850°C, SIPH temperatures up to 1,000°C, geothermal heat supply up to 150°C.

*** Industries with process temperatures above 1,000°C (i.e., lime and cement, iron and steel) were not addressed in the analysis estimating potential alternative heat supply, although the report discusses applicable alternatives. Likewise, industries that rely on their process byproducts for combustion fuels (i.e., pulp and paper, petrochemical manufacturing) were also excluded from the estimates of potential alternative heat supply.

Our calculations indicate that the largest end uses of combustion energy in 2014 were combined heat and power (CHP) and/or cogeneration (37% of calculated energy use), conventional boiler use (32%), and process heating (24%). Natural gas was the most-used fuel by the target industries, accounting for 44% of calculated combustion energy use. Data reported for combustion-unit type had limited utility because the majority of fuel combustion was designated as “other combustion source.”

The geographical distribution of these industries is illustrated in Figure ES-1. Not surprisingly, the ethanol production and pulp and paper industries are situated within the agriculture belts of the country. Large refineries are located near estuaries and oil production fields (i.e., Gulf shores, Great Lakes, ocean inland bays). The majority of petroleum-based chemical industries are located in proximity to the petroleum refineries. With the growth of metals recycling, about one-half of the steel industry is spread throughout the United States. The other half of steel making is from iron ore and is mainly located around the Great Lakes and Southeast regions. Minerals and fertilizer production is scattered around the country where the minerals are located.

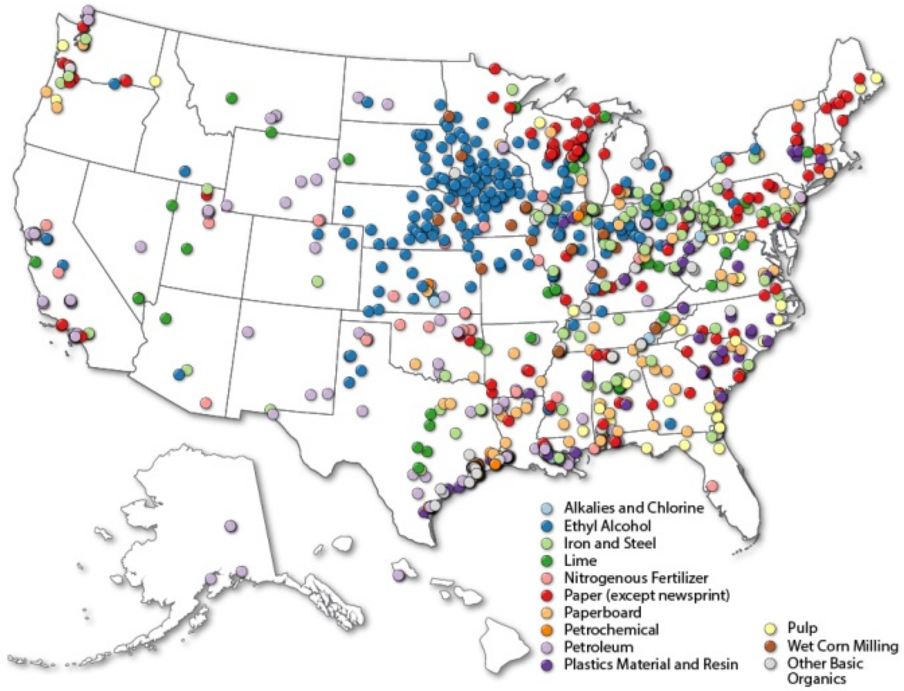

Figure ES-1. Geographical location of industries evaluated for alternative clean heat provisions

The summary of findings includes the following highlights:

1. Fourteen industries were selected for process-level thermal analysis. In 2014, 960 plants representing these industries reported emissions under the GHGRP. They constitute less than 0.5% of all U.S. manufacturing facilities but are responsible for nearly 25% of U.S. GHG inventory industrial-sector emissions, which equates to 5% of U.S. total emissions in 2014. Most of the remaining 75% of industrial GHG emissions is therefore tied to smaller facilities that fall under the EPA reporting limits for large GHG emitters.

2. Calculated combustion energy use in 2014 by the 14 target industries was 5,824 petajoules (1 PJ = 10^{15} J) or 5.520 quads—nearly 50% of 2010 manufacturing combustion energy use estimated by the EIA Manufacturing Energy Consumption Survey (MECS).
3. Within those 14 industries, CHP and conventional steam boilers account for about 70% of the heat loads. Those and other fossil-fired heating systems could be substituted by clean heat sources generating steam, hot gas, and heating other heat-transfer media. Options for clean heat sources include emerging SMRs, SIPH, and geothermal sources, as their scales are applicable to individual industry needs.
4. Most process heating within these 14 industries is accomplished with steam jackets, heating coils, and indirect heat exchangers that transfer heat from a hot gas (generally combustion gases) to the process reactor. Clean heating systems could replace the combustion gas systems by using heat circulation systems such as those described in this report.
5. Several industrial heat users, such as oil refineries, pulp/paper manufacturing, methanol, fertilizer plants, corn wet milling plants, and some inorganic mineral plants, have duties in excess of 10 TJ/day (9,500 MMBtu; 120 MWt). SMR technologies are expected to be well-matched to this scale of demand.
6. SIPH applications could potentially supply heat to the majority of the industrial applications analyzed here. Specific examples include chlorine/alkali plants, certain chemical production plants, and food processing plants. Currently, all of the major concentrating solar projects in the United States are in the Southwest, with a few in Florida and Hawaii. Technical and economic feasibility of SIPH systems for industrial heating depend on solar insolation at—or nearby, based on heat transport opportunities—the location of the facility, as well as space available for concentrating solar energy systems and heat storage systems.
7. Geothermal energy could provide thermal energy to food processing plants and to plants that use lower temperature heat to concentrate and/or dry process feedstocks and products, such as wet corn milling. Current geothermal energy production techniques for thermal applications usually provide lower temperature energy (typically ranging from 50–150°C) than is required by many manufacturing industries. Enhanced geothermal systems that could achieve higher temperature output are currently being developed.
8. The design of heat transport from SMR and SIPH sources to the industrial user may be optimized with a heat circulation system that uses a liquid heat transfer media—such as a molten salt or Dowtherm™— to deliver thermal energy over relatively long distances. Heat transfer to a hot gas or steam loop may then optimally interface with the heating coils or boiler tubes that are used in most industrial processes.
9. Heat recuperation and temperature boosting are important thermal energy management concepts that may benefit SMR, SIPH, and geothermal energy sources. For example, high temperature heat pump concepts, including adsorption/desorption chemical cycles, or renewable hydrogen could help boost the temperature of heating media.
10. Hybrid thermal/electricity generation may help balance hourly, daily, and/or seasonal electrical cycles. Seasonal heat load opportunities include food processing and/or

dehydration, conversion of biomass to intermediate products by drying, torrefaction, pyrolysis oil production and stabilization, ethanol production, hydrogen production, industry waste-water cleanup or brackish-water desalination, and pumped hydro and compressed-air storage.

11. Intermittent or batch plant operations may require thermal energy storage systems that match clean energy delivery with thermal load schedules.
12. Electrification of industry warrants further consideration. Thermal energy storage concepts such as those being developed for concentrating solar systems may help coordinate grid profiles with industry heat use profiles. Direct electrical heating is technically feasible but could add to grid response dynamics and challenges.
13. Hydrogen production for use as a substitute fuel gas by industry could reduce industry GHG emissions. Hydrogen can also replace carbon that is used as a reducing agent in steel manufacturing. Hydrogen that is produced by water splitting would provide carbon-free hydrogen for these uses.
14. SMRs were identified as an option for process heat and hydrogen production for feedstock use. The number of SMRs theoretically required to meet the heat and hydrogen requirements of applicable target industries was estimated. The potential number of SMRs that could be built may be limited to siting restrictions and licensing restrictions. A similar analysis to estimate the theoretical number of geothermal and SIPH plants was not conducted because of large variability in available heat capacity.
    a. To supply heat to industry and hydrogen as feedstock to refineries, steel production, and plastic materials and resins production, 850 SMRs, rated at 150 MW_t, would be necessary. More would be needed if industries with a heat duty under 150 MW_t are located in a cluster. This report identified opportunities to use approximately 314 SMRs to supply 1,480 PJ/yr of heat ranging up to 850°C. This heat potential does not include hydrogen combustion because SMRs were assumed to supply hydrogen for feedstock use only. The pulp and paper and petrochemical industries have suitable temperature ranges but were excluded from this total due their reliance on process byproducts as combustion fuels.

    b. Petroleum refineries use 9,130 metric tonnes/day of hydrogen. All of the refinery merchant hydrogen demand could be met by 309 light-water SMR modules.

    c. Substitution of hydrogen for coke in U.S. steel production would use an additional 6,690 metric tonnes/day of hydrogen. All of the merchant hydrogen for the steel industry could be met by 226 light-water SMR modules.

15. SIPH and geothermal energy systems are theoretically scalable to any load. Commercial systems for SIPH range from 100 kW_t for small industries to approximately 1,000 MW_t for concentrating solar power (CSP) systems. SIPH and geothermal energy may be impractical in some locations due to resource quality.
    a. SIPH could theoretically supply up to 1,480 PJ/yr to 8 of the 14 target industries identified in this report before considering practical temperature and spatial constraints. The pulp and paper and petrochemical industries have suitable

temperature ranges but were excluded from this total due their reliance on process byproducts as combustion fuels.

b. By comparison, geothermal systems that can provide a heat supply media at 150°C could provide up to 70 PJ/yr to the wet corn milling industry.

Analysis opportunities related to these observations and finding are listed in this report. Recommendations include additional nuclear-renewable hybrid energy system case studies, assessment of industry electrification options, evaluation of thermal energy storage buffers and heat-transfer systems, detailed evaluation of SIHP and geothermal energy resource potential for industrial heating, and technical/economic assessment of the benefits of hydrogen production for industrial use.

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1 Introduction

On December 15, 2015, the United States joined more than 150 other countries at the 21st session of the Conference of the Parties (COP21) in approving the Paris Agreement. The agreement includes the aim to achieve rapid reductions in greenhouse gas (GHG) emissions that will result in net zero emissions in the second half of this century (UNFCCC 2015). The United States has pledged to reduce its emissions by 26%–28% below 2005 levels by 2025 (Department of State 2015). In 2014, the United States achieved net emissions 8.6% below 2005 levels (EPA 2016a).

In 2014, the industrial sector was the third-largest source of direct[3] U.S. GHG emissions—behind electricity generation and transportation—accounting for roughly 20% of total emissions (EPA 2016a). About 52% of U.S. industrial direct GHG emissions are the result of fuel combustion (EPA 2016). Use of combustible fuels is mostly driven by the demand for indirect heat in the form of steam from boilers and heat supplied directly to process reactors by *in-situ* combustion or process reactions. As a result, mitigating industrial direct GHG emissions necessarily involves changes to the ways that heat demands are met. This report provides an understanding of the opportunities for low-GHG-emitting thermal energy sources in the current industrial landscape.

Unlike emissions from all other economic sectors in the United States, industrial GHG emissions were below 1990 levels in 2014. Several factors have resulted in this emissions decline, including structural change of the economy, fuel switching, and energy efficiency. However, the sector's overall downward emissions trend has slowly reversed since the Great Recession (2007–2009) and emissions have nearly returned to pre-recession levels.

As shown in Figure 1, industrial GHG emissions look much different through a global lens. The rapid rise in emissions that began in the early 2000s has continued into the current decade, largely unabated. Between 1990 and 2005, global direct emissions increased at an average annual rate of 0.7%; from 2005 to 2010, the average annual growth rate rose more than five-fold to 3.9% (Fischedick et al. 2014a).

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[3] Direct emissions are the result of activities that occur on-site at a facility. See https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions#industry.

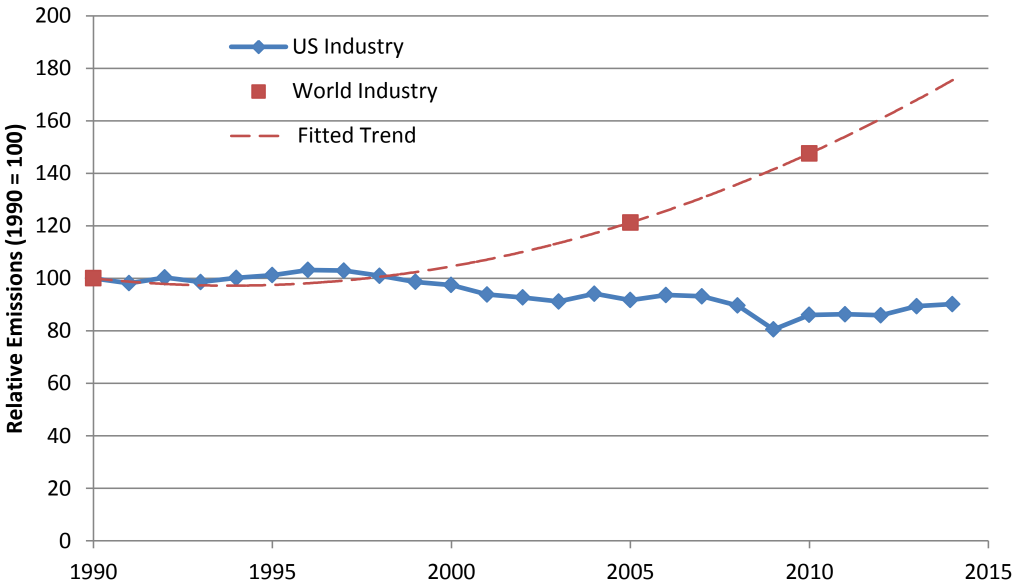

Figure 1. Trends in industrial GHG emissions for the United States and the world

Note: Data on direct, process, and low-CO_2 emissions from EPA (2016a) and Fischedick et al. (2014a).

The heterogeneity of industrial processes and the complexity of modern industrial firms' global supply are among the sector's unique challenges to mitigating its GHG emissions. As a result of these challenges, achieving absolute reductions in industrial GHG emissions requires a varied combination of strategies, such as energy efficiency, material efficiency, and switching to low-carbon fuels (Fischedick et al. 2014a). Recent analysis, however, questions whether current mitigation planning has paid sufficient attention to the sector. A 2015 review of 17 global decarbonization scenarios published from 2007 to 2012 found it "striking that relatively little planning has apparently occurred for the decarbonization of a sector responsible for one fifth of global emissions" (Loftus et al. 2015, 106). These concerns may be diminished by the more recent publication of individual industry decarbonization roadmaps for the European Union (e.g., Ecofys 2013; Wortler et al. 2016; CEMBUREAU 2013; UK Department of Energy & Climate Change and UK Department for Business, Innovation & Skills 2015). U.S. industry has not yet received such a detailed analytical treatment for decarbonization, either on a national level (Williams et al. 2015) or a state level (Wei et al. 2013; Yang et al. 2014; Wei et al. 2014; Greenblatt 2015).

The purpose of this report is to quantify the energy use and emissions for the most significant GHG-emitting U.S. industries based on targeted, process-level analysis of industrial heat requirements and to identify opportunities for those heat requirements to be replaced by low-GHG-emitting thermal energy sources. The target industries were chosen based on the magnitude of fuel-combustion GHG emissions. An analysis supporting this selection was conducted using national GHG inventory data and reported facility-level GHG emissions data from the U.S. Environmental Protection Agency (EPA). Our calculation of facility-level thermal energy demands from reported GHG emissions data by fuel type provides a level of detail that was not available from existing, publicly available industrial energy data sources such as the Energy Information Administration (EIA) Manufacturing Energy Consumption Survey (MECS) and State Energy Data System (SEDS).

A detailed analysis was then performed for the target industries to identify relevant flows of energy, water, carbon dioxide (CO_2), and finished product for a typical facility. Identified characteristics of the industrial process and their heat requirements frame the discussion of relevant alternative heat supplies. Specifically, the scale and temperature of the required heat and heat-transport distance were considered as criteria for matching in-plant heat demands with external, alternative heat supplies. These alternatives included small module reactors (SMRs), solar industrial process heat (SIPH), and electrical heating.

Although a collection of technical, regulatory, and policy challenges exists, industry adoption of alternative heat supplies may offer the potential for additional benefits beyond reductions in GHG emissions and energy use. The alternative heat supplies identified in this report could serve as a foundation for clustering facilities in energy parks, which offers opportunities to effectively share energy and other resources, such as water. Additionally, alternative heat supplies that reduce operation costs or improve productivity could benefit the competitive edge of U.S. manufacturing.

Section 2 provides an overview of industrial GHG emissions, identifies the 14 most significant GHG-emitting industries, and describes the method used to estimate thermal energy demands by end use from reported GHG emissions data. Section 3 summarizes the results of process-level analysis of heat quantity and quality of the target industries. Section 4 discusses relevant alternative heat supplies and heat transfer considerations. Section 5 identifies analysis opportunities and Section 6 concludes the report. The report appendices provide additional background and technical detail of the process-level analysis summarized in Section 3.

2 Industrial Heat Survey

The lack of publicly available energy data at the process and technology level is a challenge to mitigating industrial GHG emissions (Fischedick et al. 2014a). This section attempts to reduce the severity of this challenge by providing estimates of U.S. industrial thermal energy use at levels of detail not previously available to the public. Specifically, we calculated combustion energy use for detailed industries based on GHG emissions data reported on a facility level, identified the largest energy-using industries, and quantified combustion energy by end use. Section 2.1 describes the EPA Greenhouse Gas Reporting Program (GHGRP) and its data and identifies industries with the most significant GHG emissions from combustion. Section 2.2 describes the calculation of combustion energy use from GHG emissions data and compares the energy-use results with existing publicly available industrial energy data. Section 2.3 summarizes the conclusions of the analysis.

2.1 Selecting Industries for Detailed Energy Analysis

Fourteen industries were selected for assessing their emission characteristics based on analysis of national GHG inventory data and reported facility-level GHG emissions data obtained from the GHGRP. This selection then served as the starting point for detailed analysis that identified relevant flows of energy, water, CO_2, and finished product for a typical facility in each target industry.

2.1.1 EPA Greenhouse Gas Reporting Program

National, state, and local-level GHG inventories identify the general sources of industrial-sector GHG emissions but do not provide industrial emissions by industry type, facility, or energy end use. Development of effective strategies for emissions reduction could benefit from a more detailed view of the types of industries and their end uses that primarily drive emissions and energy use. This has recently been made possible by the U.S. EPA's GHGRP, which began in 2010. Under the Mandatory Reporting of Greenhouse Gases Rule (Part 98), facilities with annual direct emissions greater than or equal to 25,000 metric tons CO_2-equivalent ($MTCO_2e$) are required to report to the EPA ("Mandatory Greenhouse Gas Reporting" 2009). Over 8,000 facilities representing nine industry sectors[4] reported direct emissions of 3,200 million $MTCO_2e$ ($MMTCO_2e$), or nearly half of U.S. total GHG emissions, for the 2014 reporting year (EPA 2016b).[5] The majority of reported emissions come from power plants, which were responsible for 66% of total reported emissions (2,100 $MMTCO_2e$) in 2014. Power plants include units that previously reported CO_2 mass and heat input to the EPA year-round under 40 CFR part 75 (Continuous Emission Monitoring 1993). The remaining 34% of reported emissions are mostly associated with industrial facilities.

GHGRP data are available from EPA's Envirofacts database and can be accessed based on Part 98 Subpart subject (EPA 2016c). Over 30 subparts exist; these address emissions from fossil-fuel combustion and industrial processes, as well as the production of fossil fuels, such as gasoline, that are combusted by other sectors. GHG emissions associated with industrial heat occur when

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[4] The EPA identifies these nine industry sectors as power plants, petroleum and natural gas systems, refineries, chemicals, waste, metals, minerals, pulp and paper, and "other" (EPA 2016b).

[5] The GHGRP covers 85%–90% of total U.S. GHG emissions when supplier emissions are included (EPA 2016b).

fuels are combusted for direct use (e.g., process heating) or indirect use (e.g., in conventional boilers or for cogeneration). Data most relevant for analysis of industrial energy use are reported under Subpart C—General Stationary Fuel Combustion Sources and Subpart D—Electricity Generation. Including only GHGRP reporters that identify as part of the industrial sector,[6] emissions reported under Subpart C and Subpart D totaled 529 MMTCO$_2$e in 2014.[7] Put into context of the U.S. GHG emissions inventory, the industrial facilities reporting under these subparts account for 32% of all industrial-sector emissions and 7% of U.S. total emissions.[8]

2.1.2 Identifying Industrial Energy Survey Target Industries

We first aggregated GHGRP-reporter data at the industry subsector level based on their three-digit North American Industrial Classification System (NAICS)[9] code to determine which industries are the most significant direct GHG emitters. Emissions significance screening was performed in terms of largest absolute emissions (>2.5 MMTCO$_2$e) and largest facility mean emissions (>0.07 MMTCO$_2$e) by subsector. This initial screening identified eight subsectors as candidates for more detailed, process-level analysis based on subsector total emissions and facility mean emissions. The sum of reported emissions from these subsectors represents nearly 30% of the U.S. GHG inventory industrial sector total. Note again that the analysis includes only emissions reported under Subpart C—General Stationary Fuel Combustion Sources and Subpart D—Electricity Generation (excluding utility fossil-fuel electric power generators).

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[6] The industrial sector comprises agriculture (NAICS code 11), mining (NAICS code 21), construction (NAICS code 23), and manufacturing (NAICS codes 31–33) establishments.

[7] GHG emissions from biomass combustion are included in this total because the ultimate analysis goal is to characterize industrial heat demands, regardless of the energy carrier combusted. Disregarding reported CO$_2$ emissions from biomass reduces industry emissions to about 486 MMTCO$_2$e, equivalent to 33% of all industrial-sector emissions and 7% of U.S. total emissions.

[8] Although the EPA national inventory does not include CO$_2$ emissions from biomass in reported sums, these emissions have been added to industry (124.4 MMTCO$_2$e) and national (217.7 MMTCO$_2$e) totals as a more appropriate comparison with GHGRP-reported emissions.

[9] NAICS is a system of six-digit hierarchical codes used to categorize economic activity. The first two digits indicate the sector, the third digit the subsector, the fourth digit the industry group, the fifth digit the industry, and the sixth digit the U.S.-specific industry.

Table 1. EPA GHGRP-Reported Emissions Data by U.S. Industry Subsector (Three-Digit NAICS Code) for 2014

Industry Subsector	NAICS Code	Number of Reporting Facilities	Facility Mean Emissions[a] (MMTCO$_2$e)	Total Emissions[a] (MMTCO$_2$e)	Fraction of Industry Sector Emissions[a] (%)
Petroleum and Coal Products	324	176	0.731	129	8
Chemical Manufacturing	325	616	0.180	111	7
Primary Metals	331	272	0.244	66	4
Paper Manufacturing	322	230	0.302	70	4
Food Manufacturing	311	322	0.112	36	2
Nonmetallic Mineral Products	327	326	0.070	23	1
Wood Product Manufacturing	321	22	0.123	2.7	0.2
Agriculture	111, 115	5	0.139	0.694	0.04
Total		**1,969**	**0.223**	**438**	**27**

[a] Includes CO$_2$ from biomass combustion.

To more specifically target the most significant GHG emitters, we separated industry subsectors by U.S.-specific industry based on six-digit NAICS codes and selected industries with the highest total and facility mean emissions. This revealed 14 industries that were selected for process-level analysis.[10] As shown in Figure 2, the direct-combustion emissions of the 960 facilities in these industries collectively constitute nearly one-quarter of U.S. GHG inventory industrial-sector emissions, equivalent to 5% of U.S. total emissions in 2014. Table 2 summarizes reported emissions by target industry. Appendix A summarizes general descriptions of the activities of each target industry. Later in the report, we provide further discussion on production process, energy intensity of the process (energy consumption per unit of manufactured product), along with power requirement and net emissions for the target industries.

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[10] The selection threshold was industry total emissions above 10 MMTCO$_2$e, but this was amended to include lime manufacturing, nitrogenous fertilizer manufacturing, and potash, soda, and borate mining based on their facility mean emissions (>0.2 MMTCO$_2$e). Industries that were excluded from selection include primary aluminum production, industrial gas manufacturing, cement manufacturing, glass container manufacturing, and iron foundries. In sum, 2,351 facilities representing 193 specific industries and 160 MMTCO$_2$e emissions were excluded from the analysis.

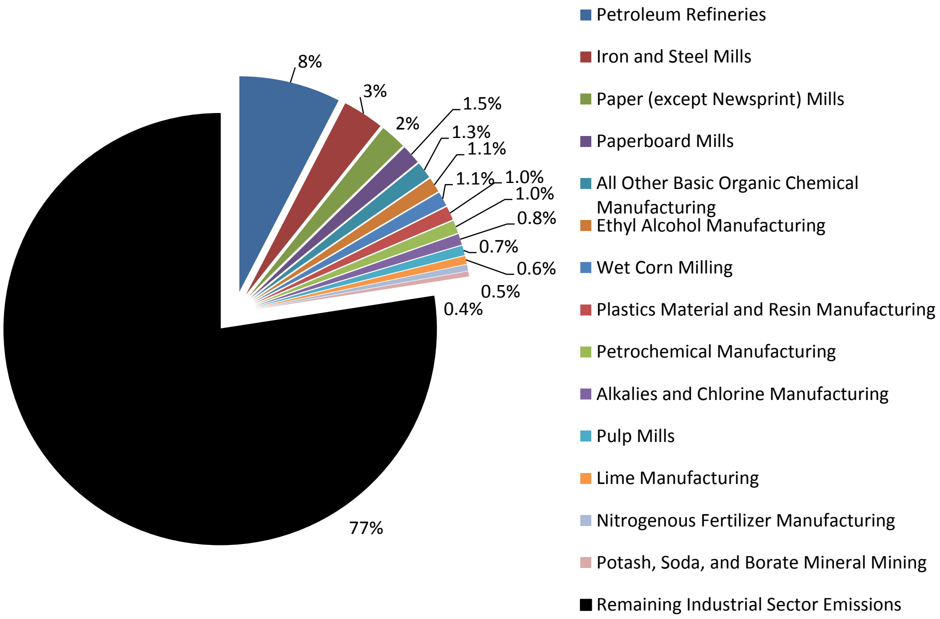

Figure 2. Target industry fraction of industrial sector total GHG emissions for 2014

Table 2. EPA GHGRP-Reported Emissions Data by Target Industry for 2014

Industry Subsector	Target Industry	NAICS Code	Number of Reporting Facilities	Facility Mean Emissions $(MMTCO_2e)$ [a]	Total Emissions $(MMTCO_2e)$ [a]	Fraction of Industrial Sector Emissions (%)[a]
Petroleum and Coal Products Manufacturing	Petroleum Refineries	324110	141	0.882	124	8
Primary Metal Manufacturing	Iron and Steel Mills	331111	115	0.440	51	3
Paper Manufacturing	Paper (Except Newsprint) Mills	322121	116	0.275	32	2
	Paperboard Mills	322130	73	0.327	24	1.5
	Pulp Mills	322110	30	0.395	12	0.7
Chemical Manufacturing	All Other Basic Organic Chemical Manufacturing	325199	85	0.245	21	1.3
	Ethyl Alcohol Manufacturing	325193	168	0.109	18	1.1
	Plastics Material and Resin Manufacturing	325211	72	0.235	17	1.0
	Petrochemical Manufacturing	325110	35	0.450	16	1.0
	Alkalies and Chlorine Manufacturing	325181	11	1.223	13	0.8
	Nitrogenous Fertilizer Manufacturing	325311	30	0.252	8	0.5
Food Manufacturing	Wet Corn Milling	311221	24	0.744	18	1.1
Nonmetallic Mineral Product Manufacturing	Lime Manufacturing	327410	49	0.201	10	0.6
Mining (Except Oil and Gas)	Potash, Soda, and Borate Mineral Mining	212391	11	0.568	6	0.4
Total			**960**	**0.385**	**369**	**23**

[a] Includes CO_2 from biomass combustion.

Figure 3 summarizes the 2014 GHG emissions of the 14 target industries in relation to GHGRP-reported emissions for all industries and industrial-sector emissions. Industrial-sector emissions have been identified as stationary combustion, industrial processes,[11] and non-energy use and fossil-fuel systems (i.e., coal mining, natural gas systems, and petroleum systems). The figure shows that industrial facilities subject to the GHGRP-reported emissions of 529 $MMTCO_2e$ from fuel combustion, which is the equivalent of 56% of U.S. GHG inventory industry stationary combustion emissions. The target industries represent nearly 40% of U.S. GHG inventory industry stationary combustion emissions.

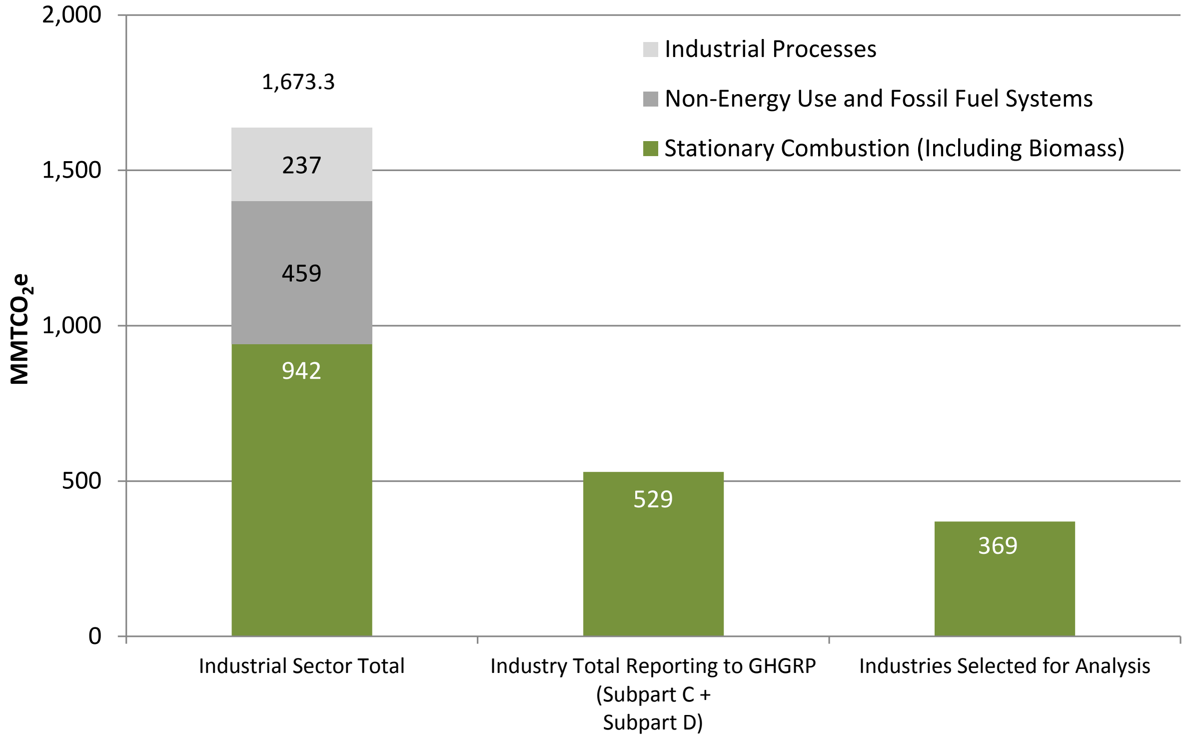

Figure 3. U.S. industrial GHG emissions in 2014

Source: Data from EPA (2016a); EPA (2016b)

2.2 Combustion Energy Use Analysis of Target Industries

We used GHGRP-reported data and GHG emissions factors to calculate facility combustion energy use for the 14 target industries. This section details the three calculation approaches that we applied to GHGRP data and provides a summary and analysis of calculation results.

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[11] Industrial process GHG emissions occur as the result of industrial activities but not as the direct result of fossil-fuel combustion. For example, the reduction of iron ore to iron and the calcination of limestone to quicklime are industrial activities whose reactions evolve CO_2. Industrial process emissions were not considered for this analysis because they are not the direct result of fossil-fuel combustion and therefore are not impacted by the use of low-carbon alternative heat supplies.

2.2.1 Calculating Thermal Energy Use from EPA Greenhouse Gas Reporting Program Data

We calculated facility thermal energy use for the target industries based on GHG emissions data reported under Subpart C—General Stationary Fuel Combustion Sources and energy data reported under Subpart D—Electricity Generation (excluding utility fossil-fuel electric power generators). Facilities reporting GHG emissions under Subpart C use one of four calculation methodologies or "tiers." These tiers provide reporters with varying levels of specificity for the type and quantity of fuel combusted and are described as follows (EPA 2016d):

- Tier 1 emissions are calculated using default EPA emission factors (kilograms CO_2 per million British thermal units [MMBtu]) and company fuel-purchase records.
- Tier 2 emissions are calculated with default and fuel-specific data such as emission factors, measured high heating values, and company fuel-purchase records.
- Tier 3 emissions are calculated with fuel-specific data on carbon contents, higher heating values, and measured fuel quantities.
- Tier 4 emissions are measured via gas concentration and gas flow rate obtained from continuous emission monitoring equipment.
- In addition to these four tiers, facilities with combustion units that are subject to the continuous emissions monitoring requirements of 40 CFR Part 75 can calculate GHG emissions using heat-input and fuel-use data already collected for Part 75.

We used the fuel types and emissions reported under Subpart C, as well as heat-input values reported under Part 75 for Subpart D, to estimate facility annual combustion energy demand in one of three approaches.[12] Approach 1 and Approach 2 are based on reported emissions and EPA default emission factors by fuel type. Approach 3 is based on reported heat input by fuel type.

Strictly speaking, these estimates serve as proxies for total thermal energy demand because they capture only the heat content of fuels combusted for a given facility and do not include the purchases of steam and electricity that may also be used to meet heat demands. Emissions from the generation of purchased steam are captured by reporters identifying as NAICS 221330 Steam and Air Conditioning Supply. Emissions in 2014 from these facilities totaled 8.1 $MMTCO_2e$. Alternative heat supplies that substitute for purchased steam generated from fossil-fuel combustion may also be a source of GHG mitigation.

We used Approach 1 to calculate energy use from facilities reporting Tier 1, Tier 2, or Tier 3 CO_2 emissions. The energy use by fuel type was calculated by dividing the reported mass of CO_2 by the default CO_2 emission factor provided by the EPA (EPA 2015).[13] We matched reported fuel types that were not included in the EPA-provided emissions factors to their closest default fuel type.

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[12] Relevant GHGRP data are obtained from the C_FUEL_LEVEL_INFORMATION and D_FUEL_LEVEL_INFORMATION tables using the EPA Envirofacts Data Service Application Programming Interface (https://www.epa.gov/enviro/envirofacts-data-service-api).

[13] Emission factors are based on the higher heating value (HHV) of combustion fuels.

Approach 1 calculates facility energy use (in GJ [gigajoules], 10^9 J) associated with combustion fuel type t, E_t, as

$$E_t = GHG_{\mathrm{CO2},t} \div EF_{\mathrm{CO2},t} \times {}^{1.055\ \mathrm{GJ}}/_{\mathrm{MMBtu}}$$

where $GHG_{\mathrm{CO_2},t}$ and $EF_{\mathrm{CO_2},t}$ are the reported emissions and EPA default emission factors of CO_2.

We used Approach 2 to calculate energy use for facilities reporting emissions with the Tier 4 methodology. CO_2 emissions reported using Tier 4 are not included in the same dataset as Tier 1 to Tier 3 emissions, so instead, Approach 2 calculated energy use by fuel type based on reported methane (CH_4) emissions and the default methane emissions factors. We matched reported fuel types that were not included in the EPA-provided emissions factors to their closest default fuel type.

Approach 2 calculates facility energy use as

$$E_t = GHG_{\mathrm{CH4},t} \div EF_{\mathrm{CH4},t} \times {}^{1.055\ \mathrm{GJ}}/_{\mathrm{MMBtu}}$$

where $GHG_{\mathrm{CH_4},t}$ and $EF_{\mathrm{CH_4},t}$ are the reported emissions and EPA default emission factors CH_4 for fuel type t, respectively.

Energy use was calculated in Approach 3 based directly on heat-input and fuel-use data reported to the GHGRP database for facilities that are required to report under Part 75. Note that a given facility may report emissions using multiple tiers, in addition to emissions calculated from Part 75 data.

Approach 3 calculates facility energy use as

$$E_t = H_t \times {}^{1.055\ \mathrm{GJ}}/_{\mathrm{MMBtu}}$$

where H_t is the heat input in MMBtu reported under Part 75.

Figure 4 summarizes how the three approaches are applied to GHGRP-reported facility emissions and heat input by fuel type.

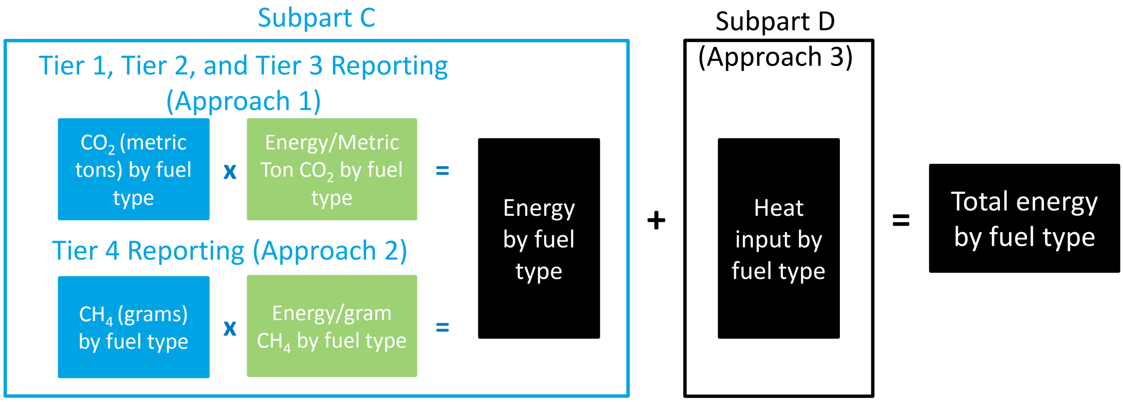

Figure 4. Generalized calculation of facility combustion energy use from GHGRP-reported emissions and heat input

Four illustrative examples of the three energy-calculation approaches are provided in Table 3. Energy use for facilities A and B was calculated using reported CO_2 emissions and the associated EPA default emission factor (Approach 1). We performed an additional calculation for facility B using CH_4 emissions and CH_4 emission factors (Approach 2) because emissions from bituminous coal combustion were reported using the Tier 4 methodology. Reported emissions are not used to estimate energy use for facility C because the facility directly reports heat-input data for distillate fuel (Approach 3).

Table 3. Illustrative Facility Annual Energy Use Estimates Calculated from Annual GHGRP Data

Facility	Reported Fuel Type	Reported Subpart C Methodology	Reported CO_2 Emissions (metric tons CO_2)	Tier 4 Reported CH_4 Combustion Emissions (metric tons CH_4)	EPA Default Emission Factor	Part 75 Annual Heat Input (MMBtu)	Estimated Energy Use in TJ (TBtu)	Estimation Approach
A	Natural Gas (Weighted U.S. Average)	Tier 1	30,000	NA	53.06 kg CO_2/MMBtu	NA	598 (0.567)	Approach 1
B	Propane	Tier 2	5,000	NA	61.46 kg CO_2/MMBtu	NA	86 (0.082)	Approach 1
B	Bituminous Coal	Tier 4	NA	75	11 g CH_4/MMBtu	NA	7,193 (6.818)	Approach 2
C	Distillate Fuel Oil No. 2	NA	NA	NA	NA	12,000	14 (0.013)	Approach 3

NA = not applicable

2.2.2 Summary of Calculated Industrial Energy[14]

The GHGRP applies only to large emitters and the increase in detail comes at the cost of overall coverage of the industrial sector. However, we note that these large emitters (and, by proxy, large fuel and energy users) are more relevant than smaller emitters (i.e., small energy users) for nuclear-generated thermal energy.

The tradeoff between detail and industry coverage is demonstrated by comparing our calculated energy data with existing, published estimates of manufacturing and state-level industrial energy use available from EIA. The latest EIA MECS represents 170,166 facilities and provides data at the six-digit NAICS code level for 47 manufacturing industries (EIA 2015). Conversely, GHGRP data in 2014 represent 2,253 facilities and 182 manufacturing industries at the six-digit NAICS code level. The 2010 MECS indicates that manufacturing industries used 12,440 PJ (11.79 quads) of fuels for combustion. In 2010, manufacturing industries reporting to the GHGRP, comprising just over 1% of the MECS sample size, are estimated to have reported the equivalent of 6,477 PJ (6.139 quads) of fuel combustion—the equivalent of 52% of the MECS fuel-combustion energy. Figure 5 makes additional comparisons between manufacturing fuel combustion as reported by the 2010 MECS and as estimated from GHGRP data for 2010 through 2014.

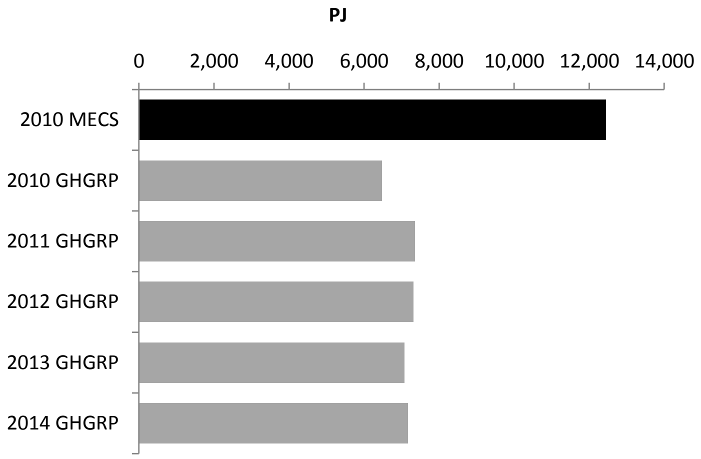

Figure 5. Manufacturing fuel-combustion energy as reported by EIA MECS and calculated from GHGRP GHG emissions data

Figure 6 depicts the number of GHGRP-reporting facilities in absolute terms and relative to facility counts from the 2010 MECS (EIA 2015) as well as the 2014 County Business Patterns (CBP) (U.S. Census Bureau 2016). As shown in Figure 6, the GHGRP represents a higher proportion of emissions-intensive industries than total manufacturing industries. GHGRP coverage is highest for Petroleum Refineries (324110), Ethyl Alcohol Manufacturing (325193), Petrochemical Manufacturing (325110), and Pulp Mills (322110). For these industries, the GHGRP represents between 61% and 91% of the CBP or MECS facility counts. The GHGRP

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[14] Calculated facility-level energy data are available from the NREL Data Catalog (https://doi.org/10.7799/1278644).

captures the fewest Plastics Material and Resin Manufacturing and Other Basic Organic Chemical Manufacturing facilities. Note that the total number of target industry facilities (960) represents 0.3% of 2014 CBP facilities and 0.6% of MECS facilities.

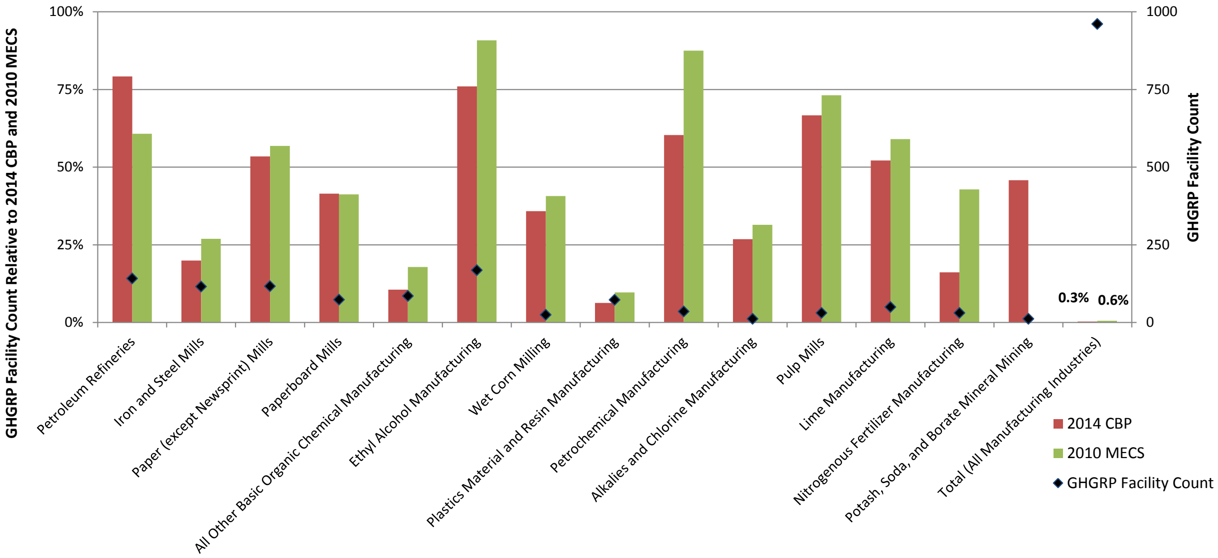

Figure 6. Absolute and relative number of GHGRP-reported target industry facilities[15]

State-level comparisons can be made between our calculated industrial-sector energy use and the EIA's SEDS. Figure 7 compares industrial-sector combustion energy (total industrial energy excluding electricity losses less electricity consumption) data with energy use calculated from GHGRP emissions and fuel-type data and aggregated by state. GHGRP estimates are shown normalized to SEDS data for a given state, with a value of 100, indicating that the values from both sources are equal. For instance, the value shown for Maine in 2013 is 72, which indicates that the industrial combustion energy use estimated from GHGRP emissions data is 72% of the energy use reported by SEDS. Figure 7 summarizes these relative values for the 10 states for which industrial energy use is most-closely and least-closely matched between available SEDS data and estimates from GHGRP data for 2013.

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[15] The 2012 NAICS revision aggregated Alkalies and Chlorine Manufacturing (325181) with Other Basic Inorganic Chemical Manufacturing (325180). The number of GHGRP-reporting facilities classified as 325181 are shown relative to the number of facilities that appear in the 2011 CBP, the final CBP to separately identify this U.S. specific industry.

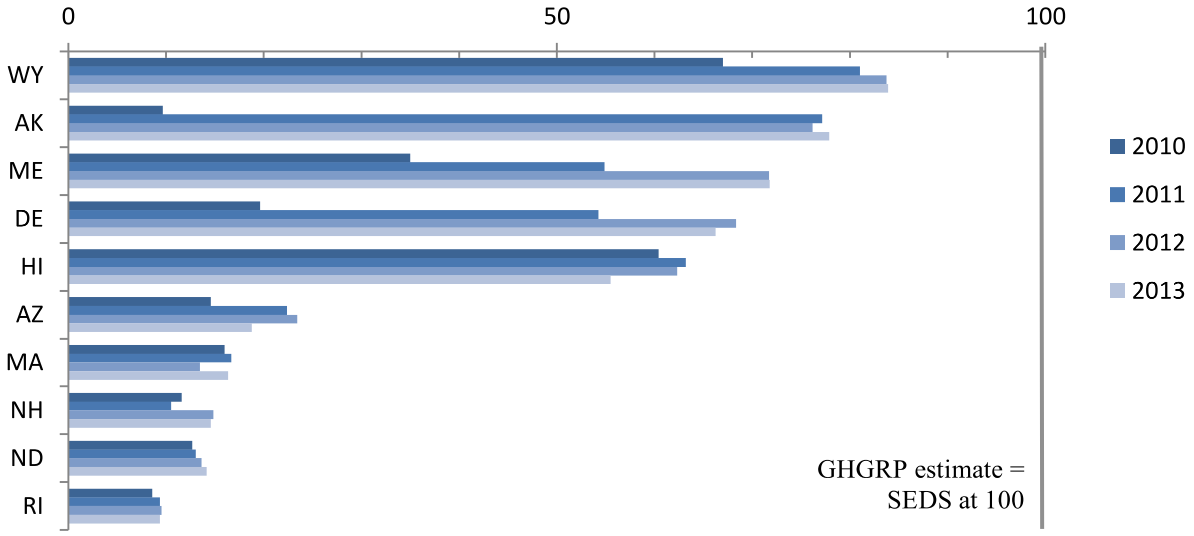

Figure 7. Relative comparison of industrial-sector combustion energy use reported by EIA SEDS and calculated from GHGRP GHG emissions data for selected states

One of the most notable differences between energy use estimated from GHGRP data and existing EIA sources is the availability of facility-level information, including facility location provided by latitude and longitude coordinates. GHGRP data allow inter-facility comparisons of GHG emissions and estimated combustion energy use. For example, Figure 8 shows the cumulative distribution of combustion energy use for iron and steel facilities. Of the 115 facilities reporting in 2014, about 90% are estimated to have used less than 10,000 TJ/year (9.48 TBtu/year) of combustion fuels.

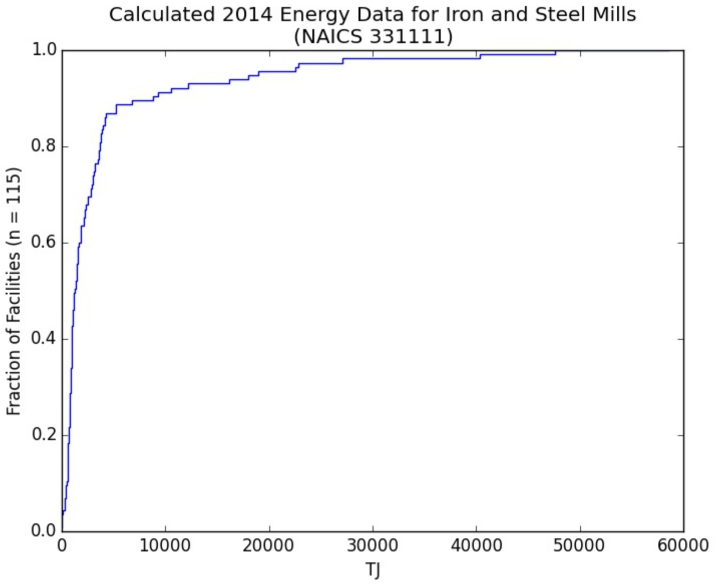

Figure 8. Cumulative distribution of calculated combustion energy use for iron and steel facilities in 2014

Estimated energy can also be broken down by fuel type. The results shown in Figure 9 indicate that natural gas is the largest source of combustion energy for the target industries.

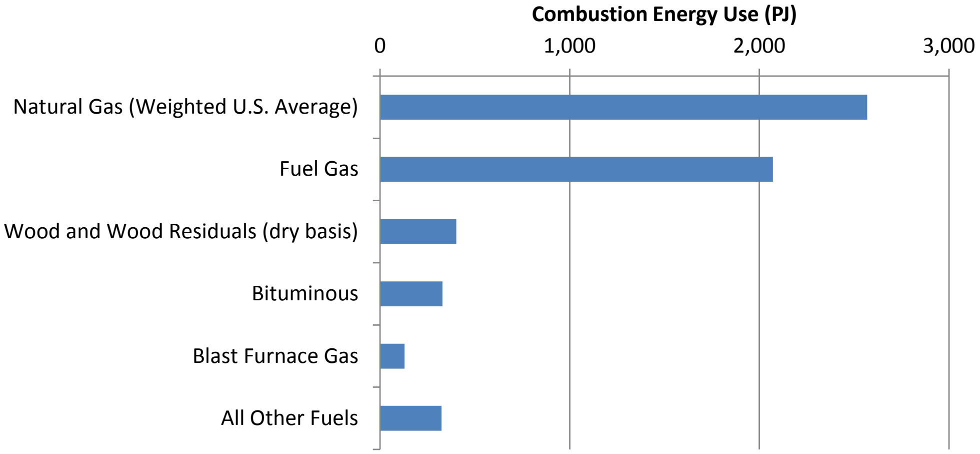

Figure 9. Calculated combustion energy use by fuel type in 2014 for target industries

2.2.3 Calculated Industrial Energy by End Use

Although the breakdown of energy use by fuel identifies one aspect of how industrial facilities meet their thermal demands, GHGRP contains additional data that provide an initial indication of what thermal demands are ultimately being met. GHGRP reporters specify the type of combustion unit that is associated with fuel use and GHG emissions. These combustion unit types include CH (comfort heater), C (calciner), MWC (municipal waste combustor), and RTO (regenerative thermal oxidizer). All told, 38 combustion unit types were reported in 2014. This data field has limited utility, however, because nearly 60% of estimated energy in 2014 is designated as OCS (other combustion source).

Table 4 summarizes the reported combustion-unit types for each of the target industries. Although 35 out of the 38 total unit types are reported by these industries, the 7 types shown represent 90% of the calculated total combustion energy for the industries. The sum of each row indicates the share of industry energy use captured by the seven combustion unit types, which ranges from as low as 47% for potash, soda, and borate mining to as high as 100% for nitrogenous fertilizer manufacturing. The final row shows the combustion-unit type share of total energy for all target industries. As expected, the OCS combustion-unit type is dominant, although it represents less than 25% of calculated energy for alkalies and chlorine manufacturing, paperboard mills, and pulp mills.

Table 4. Combustion-Unit Type Share of 2014 Calculated Combustion Energy Use by Target Industry

Subsector	Target Industry	Turbine, Combined Cycle (%)	Furnace (%)	Boiler, Other (%)	Other Combustion Source (%)	Process Heater (%)	Stoker Boiler (%)	Electricity Generator (%)	Industry Total Share (%)
Petroleum and Coal Products Manufacturing	Petroleum Refineries	1		9	65	18		5	**99**
Primary Metal Manufacturing	Iron and Steel Mills		3	14	77	6			**99**
Paper Manufacturing	Paper (Except Newsprint) Mills	2		20	29		28		**80**
	Paperboard Mills	2		29	14		37		**82**
	Pulp Mills			23	15		51		**90**
Chemical Manufacturing	All Other Basic Organic Chemical Manufacturing	17	6	10	43	3	1	18	**97**
	Ethyl Alcohol Manufacturing			4	93				**97**
	Plastics Material and Resin Manufacturing	4	14	7	53		3	2	**84**
	Petrochemical Manufacturing	4	24	11	39	14			**93**
	Alkalies and Chlorine Manufacturing	12	1	4	21			29	**67**
	Nitrogenous Fertilizer Manufacturing			10	86	3			**100**
Food Manufacturing	Wet Corn Milling			1	56		2		**59**
Nonmetallic Mineral Product Manufacturing	Lime Manufacturing				49				**49**
Mining (Except Oil and Gas)	Potash, Soda, and Borate Mineral Mining			4	32		10		**47**
	Fraction of All Target Industries (%)	**3**	**3**	**11**	**55**	**8**	**6**	**5**	

Note: Null values not shown in order to improve readability.

To overcome the limitation of the OCS designation, we applied end-use consumption data from EIA MECS to calculated energy-use data based on the reported six-digit NAICS code and fuel type. Note that MECS is conducted only for manufacturing industries (NAICS 31-33), whereas

GHGRP industrial reporters include non-manufacturing industries associated with agriculture and mining.[16] If an industry was not reported in MECS at the six-digit NAICS code level, it was matched to the next-most-detailed reporting level. For example, a facility that reports under the GHGRP and identifies as a "frozen fruit, juice, and vegetable manufacturer" (NAICS 311411) is matched to MECS end-use data for "fruit and vegetable preserving and specialty food manufacturing" (NAICS 3114). MECS data that were missing, withheld, or identified as "End Use Not Reported" were adjusted following the assumptions and methods described by Fox et al. (2011).

The summation of end-use energy for the target industries (excluding potash, soda, and borate mineral mining) calculated using MECS data is shown in Table 5.[17] The calculations indicate that the majority of energy from fuel combustion is used in boilers, either for conventional boilers or for combined heat and power (CHP)/cogeneration. The second-largest end use is direct process heating, which accounts for 24% of calculated energy use, followed by various other direct process uses and direct non-process uses.

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[16] It was not possible to calculate end-use energy for the potash, soda, and borate mineral mining industry because the industry is not included in MECS.

[17] Several facilities reported use of fuel types that are not included in MECS for the matching industry. As a result, the energy use associated with these fuels does not appear in the end-use categories. This unallocated energy amounts to about 3% of the total calculated energy use of manufacturing industries reporting to the GHGRP in 2014.

Table 5. Calculated Target Industry Energy by End Use in 2014

End Use	Calculated Energy Use in PJ (TBtu)	Share of Calculated Energy Use (%)
Indirect Uses—Boiler Fuel		
Conventional Boiler Use	1,855 (1,758)	32
CHP and/or Cogeneration Process	2,143 (2,031)	37
Total	**3,998 (3,789)**	**70**
Direct Uses—Total Process		
Process Heating	1,366 (1,295)	24
Process Cooling and Refrigeration	17 (16)	0.3
Machine Drive	174 (165)	3
Electrochemical Processes	0.3 (0.28)	0.0
Other Process Use	76 (72)	1
Total	**1,633 (1,548)**	**28**
Direct Uses—Total Non-Process		
Facility HVAC (g)	28 (27)	0.5
Facility Lighting	1 (1)	0.0
Other Facility Support	5 (5)	0.1
Onsite Transportation	2 (2)	0.0
Conventional Electricity Generation	15 (14)	0.3
Other Non-Process Use	2 (2)	0.0
Total	**54 (51)**	**1**

Note: Absolute and relative energy by end use may not sum due to rounding.

End-use calculations on an individual industry level are summarized in Figure 10, which identifies the most significant end uses for each industry. The figure also depicts the calculated energy by end use for all individual facilities that constitute the 169 remaining manufacturing industries reporting to the GHGRP in 2014, indicated by the “All Other” category. The end-use proportions for “All Other” were calculated based on the sum of calculations performed on these individual facilities. These results provide a foundation for more detailed, process-level analysis of industrial thermal demands presented in subsequent sections of the report.

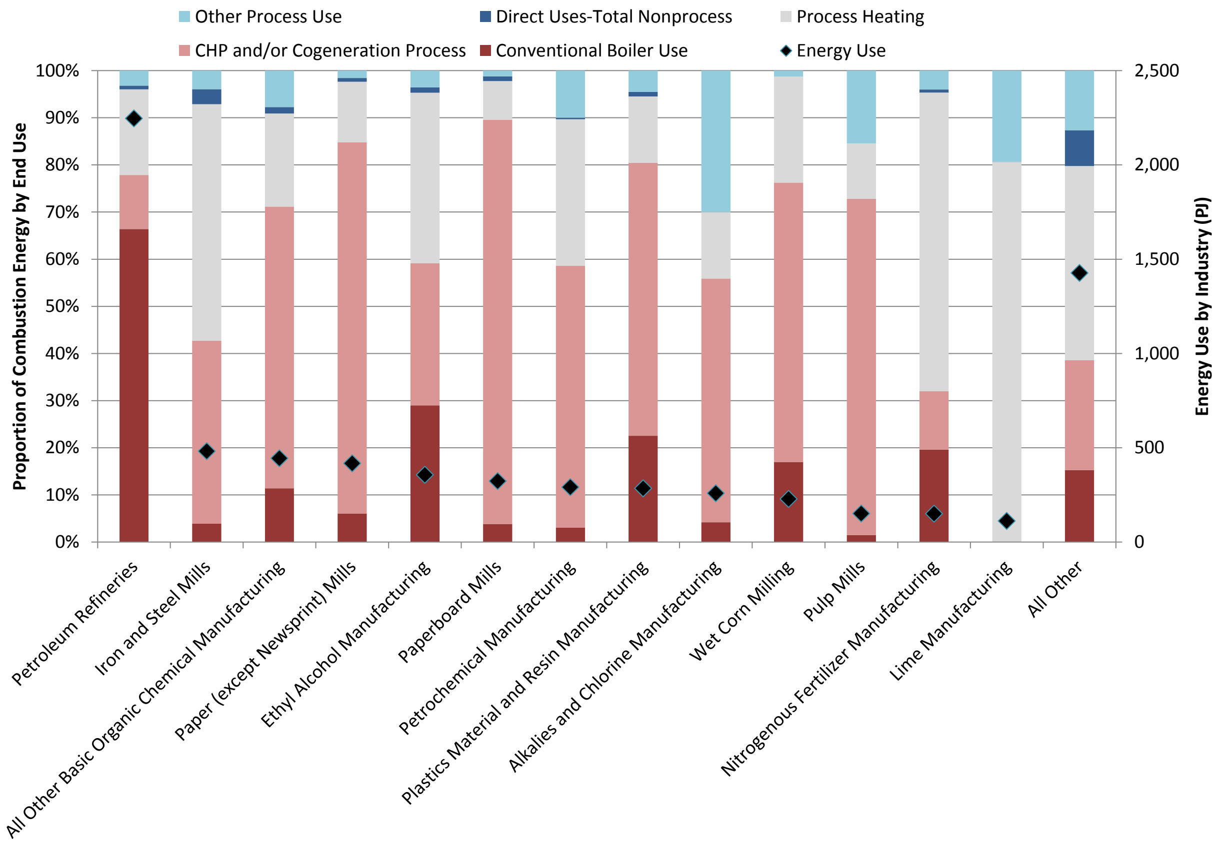

Figure 10. Calculated combustion energy by end use and target industry in 2014

Note: CHP and/or cogeneration energy use does not account for electricity generation losses. A larger version of this figure is included as Appendix B.

By combining MECS data with energy estimates based on GHGRP data, it is possible to approximate the geographic distribution of the target industries (Figure 11) and their thermal-energy end uses by industry at a much finer resolution than what was previously possible using publicly available data. Figure 12 through Figure 15 map the relative density of thermal energy by end use (i.e., total thermal, conventional boiler, direct process, and cogeneration) for the target industries. The most intensive use occurs in the Gulf Coast region of Texas and Louisiana, which is the area with the largest concentration of petroleum refining, petrochemical manufacturing, and other basic organic chemical manufacturing. Other significant areas of concentrated thermal-energy use are found in the Chicago, Philadelphia, and Los Angeles metropolitan areas. A moderate concentration of process thermal energy is spread throughout Iowa and surrounding states, which corresponds to the locations of ethyl alcohol manufacturing facilities. It is also instructive to note the areas where the target industries are not located—namely, the western interior of the country.

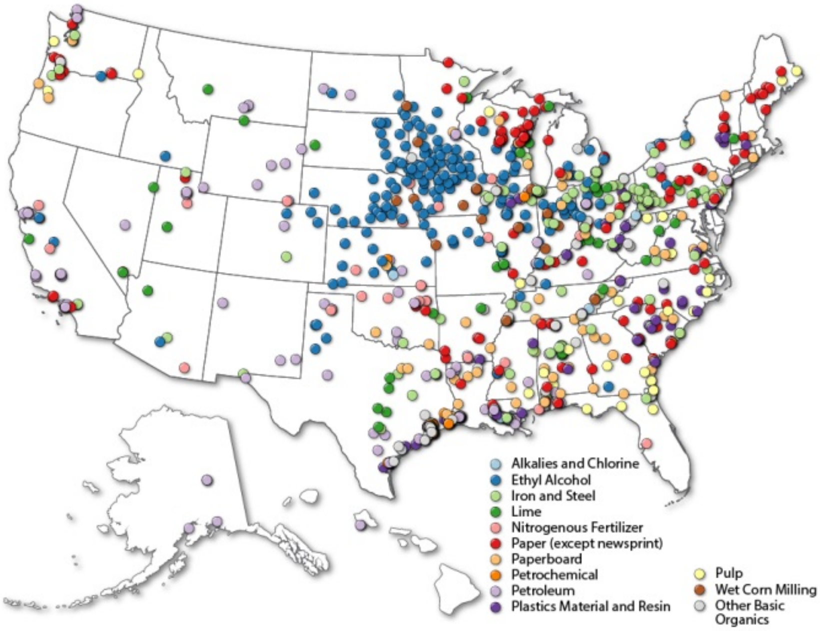

Figure 11. Facility location by target industry

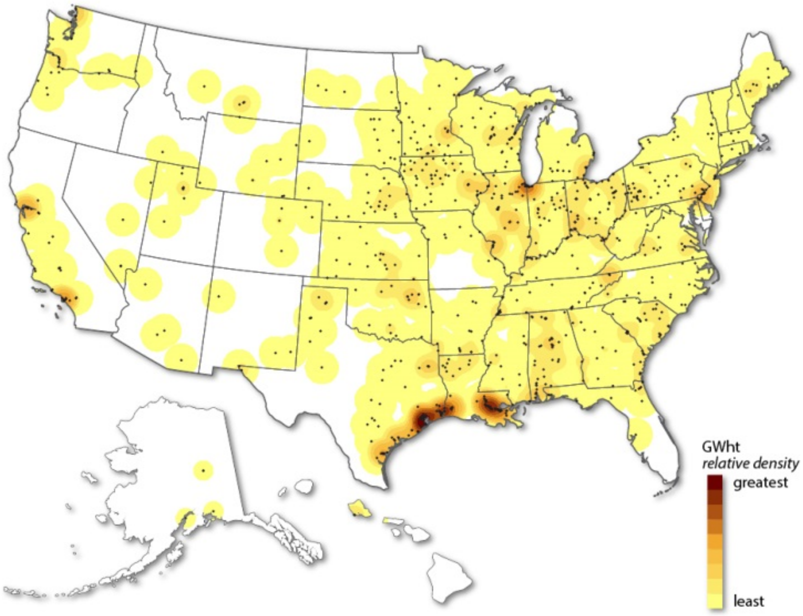

Figure 12. Distribution of target industry total thermal-energy use

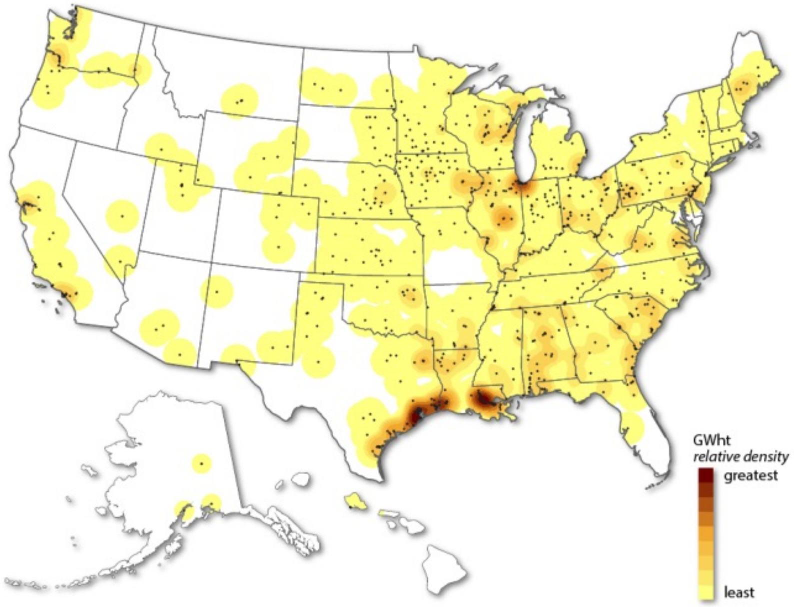

Figure 13. Distribution of target industry thermal energy for cogeneration use

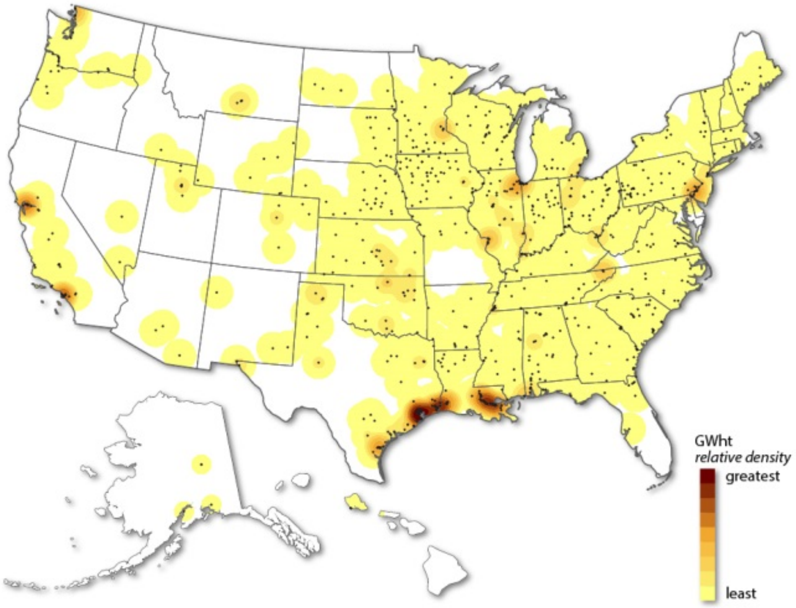

Figure 14. Distribution of target industry thermal energy for conventional boiler use

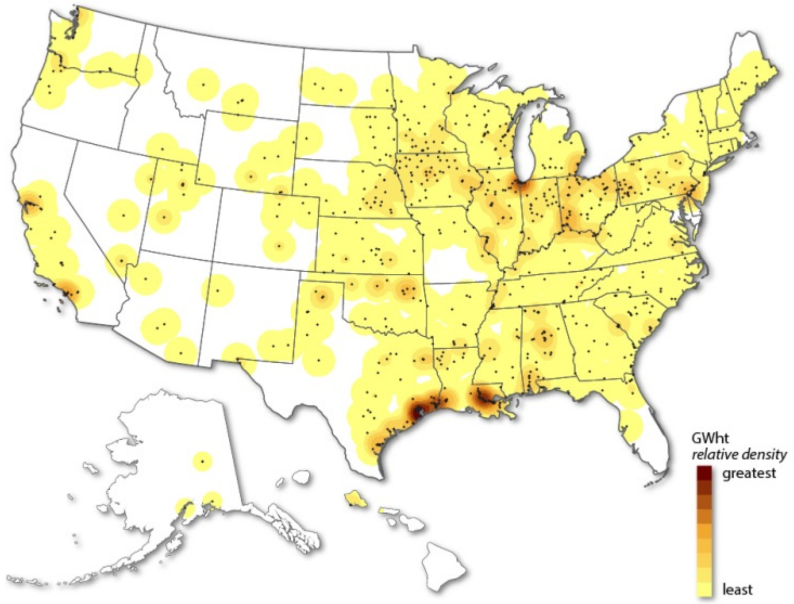

Figure 15. Distribution of target industry thermal energy for direct process use

2.2.3.1 Energy for Combined Heat and Power/Cogeneration

Table 6 indicates that 37% of calculated target industry energy use is for CHP and/or cogeneration. Given its significance as an energy end use and the multiple ways of allocating GHG emissions (WRI/WBCSD 2006), it is important to accurately account for combustion fuel energy used for CHP/cogeneration. We supplemented existing CHP/cogeneration energy estimates from EIA MECS with facility-level estimates calculated from GHGRP data.

GHGRP reporters indicate whether emissions are from CHP or cogeneration units. Using this designation, as well as information on the reported combustion-unit type, we calculated estimates of the absolute and relative amounts of combustion energy used for onsite electricity generation. Specifically, fuel use was summed for cogeneration-designated facilities that have indicated combined-cycle turbines, simple-cycle combustion turbines, or electricity generator combustion-unit types. Estimates of the fraction of total combustion energy used for CHP/cogeneration are shown by industry in Table 6. CHP/cogeneration fractions estimated from adjusted MECS end-use data are provided for reference. In all industries except alkalies and chlorine manufacturing, the fraction of CHP/cogeneration calculated from GHGRP data is substantially lower than the value provided by EIA MECS.

The estimates calculated from GHGRP data can be thought of as lower bounds of the combustion energy used for onsite electricity generation. Given the large fraction of combustion units identified as OCS (other combustion source), it is likely that some facilities reporting emissions from a cogeneration unit and indicating the combustion-unit type as OCS are actually reporting fuel use associated with CHP/cogeneration. The energy use of these facilities is not captured as energy use for CHP/cogeneration as a result. Conversely, it is less likely that reporters misidentified either their designation of emissions resulting from CHP/cogeneration or their combustion-unit type. Also note that adjusting MECS data using the assumptions and method of Fox et al. (2011) for many industries allocates energy without a reported end use and energy associated with byproducts (e.g., wood chips, blast furnace/coke oven gases, and waste gases) to CHP/cogeneration end use. The adjustments were also made based on the less-detailed three-digit NAICS code level rather than the six-digit NAICS code level used for reporting combustion-unit type.

Table 6. Estimated Fraction of Combustion Energy Used for CHP/Cogeneration

Industry Subsector	Target Industry	NAICS Code	Fraction of Combustion Energy Used for CHP/Cogeneration (GHGRP Data)	Fraction of Combustion Energy Used for CHP/Cogeneration (Adjusted MECS Data)
Petroleum and Coal Products	Petroleum Refineries	324110	0.07	0.12
Primary Metals	Iron and Steel Mills	331111	0.00	0.29
Paper Manufacturing	Paper (Except Newsprint) Mills	322121	0.03	0.85
	Paperboard Mills	322130	0.02	0.89
	Pulp Mills	322110	0.00	0.93
Chemical Manufacturing	All Other Basic Organic Chemical Manufacturing	325199	0.34	0.53
	Ethyl Alcohol Manufacturing	325193	0.00	0.32
	Plastics Material and Resin Manufacturing	325211	0.08	0.54
	Petrochemical Manufacturing	325110	0.07	0.35
	Alkalies and Chlorine Manufacturing	325181	0.73	0.54
	Nitrogenous Fertilizer Manufacturing	325311	0.00	0.13
Food Manufacturing	Wet Corn Milling	311221	0.00	0.52
Nonmetallic Mineral Product Manufacturing	Lime Manufacturing	327410	0.00	0.00
Mining (Except Oil and Gas)	Potash, Soda, and Borate Mineral Mining	212391	0.00	No Data

2.3 Conclusions

Analysis of 2014 GHGRP data revealed 14 industries that were selected for process-level analysis. The direct-combustion emissions of the 960 facilities in these industries collectively constitute nearly one-quarter of industrial-sector emissions—equivalent to 5% of U.S. total emissions in 2014. End-use calculations for the target industries indicate that the majority of energy from fuel combustion is used in boilers, either for conventional boilers or for CHP/cogeneration. The second-largest end use is direct process heating, which accounts for 24% of calculated energy use, followed by various other direct process uses and direct non-process uses. Alternate calculations of CHP/cogeneration end use were performed, but their usefulness is limited by the accuracy of facility-reported combustion-unit type.

3 Application of Thermal Energy in Industry

The aim of this section is to address applications of heat transfer in the target industries and how clean energy inputs can replace heat that is traditionally produced by burning carbon-containing fuels. The discussion of each industry provides a complement to existing U.S. Department of Energy (DOE) resources on industrial heat (e.g., DOE 2016a; DOE 2015c; DOE 2015d; DOE 2015e; Thekdi and Nimbalkar 2014).The common feature of the target industries is that they convert raw materials into energy services by means of physical and chemical changes through a series of process steps. These changes generally require thermal energy to affect solids and liquids heat-up, melting, and evaporation. Thermal energy is also needed to heat up reactants to initiate molecular bond breaking and to sustain the propagation of endothermic reactions and even slightly exothermic reaction mechanisms that are easily curtailed by chain-termination reaction steps. Thermodynamic considerations necessitate operation of many chemical processes at the highest temperature possible, even with the aid of catalysts, to attain high conversion efficiencies and to reduce reactor-vessel sizes. In the case of highly exothermic reactions, including synthesis of many organic molecules, heat must be removed to manage reaction efficiency, product volatility, or to avoid reactor-materials degradation. Electrochemical and electrocatalysis processes may reduce the thermal duty of chemical conversion processes; consequently, interest in developing process steps based on electrochemistry is on the rise with advances in materials science and nanotechnology and the advent of effective solar PV energy (Botte 2014). Heat deposition by electromagnetic heat transfer, such as infrared heating, may also enhance process intensification and deep decarbonization.

Thermal energy differs from electrical and chemical energy to the extent that high-grade heat cannot be cost-effectively delivered over long distances without significant heat loss or expensive pipe insulation and/or double-wall air-gap pipe. Very high-temperature gases (>750°C) further require a corrosion-resistant alloy or refractory lining. Fluid compressors, pumps, and control valves must be compatible with the heat-transfer fluid (or media). Pipe runs must be built to handle thermal-expansion stresses during process start-up and shut-down, intermittent operation, and unplanned disruptions in flow conditions.

In summary, in addition to cost, heat-delivery and heat-transfer system design considerations include:

- Chemical-process considerations
    - Temperature of reactor-unit operations
    - Heat-rate requirements and profile (continuous or batch)
    - Reaction regimes (gas/liquid/solid mixing and contact)
    - Reactor design (fixed-bed, fluid-bed, entrained particles; well-stirred or plug-flow)
    - Mode of heat transfer (direct or indirect contact on heat-transfer fluid, convective or radiative).
- Heat transport, delivery, and process transfer considerations
    - Distance of heat source to multiple-unit operations or multiple plants

  - Heat-transfer fluid (physical and thermodynamic properties and rheology)
  - Heat-loss control
  - Heat-exchanger design
  - Safety (chemical toxicity and radioactivity)
  - Corrosion and erosion of heat-transfer materials and flow motive and control equipment.

Chemical-process considerations are later identified in Table 8 for the major thermal demands for each target industry. Heat transport, delivery, and process transfer considerations are discussed in detail in Section 4.

3.1 Chemical Process Heat Utilization

Heat input drives at least one or more process steps for the majority of the chemical conversion processes, as demonstrated by the major chemical and biological reactor processes highlighted in this report. Many of the process steps employ indirect heating:

- Fermentation
- Pasteurization and purification
- Drying and evaporation (e.g., distillation)
- Desorption
- Solids melting
- Dehydrogenation
- Chemical purification and separation
- Thermal cracking
- Hydrothermal cracking and hydrothermal treatment of large organic molecules
- Endothermic process steps of steam-methane reforming
- Depolymerization and organic molecule scissioning.

Some process steps combine *in-situ* chemical-reactor heat generation and direct contact with chemical conversion reactions that generate heat and add reactant species to the unit operation:

- Auto-thermal steam-methane reforming
- Smelting and calcining ores
- Coke production for iron making and iron ore smelting by iron reduction
- Alloying of metals, metals purification, and annealing
- Glass production
- Refractories production and firing of ceramics and coatings.

Many processes for industries identified in this report involve heating in multi-tubular gas flow reactors, trickle-bed tubular reactors, and agitated liquid vessels. An outside jacket, external limpet coil, or internal tube coil is employed to transfer heat from steam or hot gas (from a fired heater) to these chemical reactors. Because the flow through the jacket or coils depends on the position of inlet and outlet connections, substitution of hot gas, liquid metals, or molten salt for steam can be effective if the substitution provides equivalent or better heat-transfer rates. Assessment of the heat capacity of the substitute fluids, their heat-transfer coefficients and rheological properties, heat jacket or coils material compatibility, and changes in mechanical stresses can be considered.

Solids-handling chemical reactors include fluidized beds, rotary drums and rotary/sheeted drum, and horizontal rotary-driven/mixing ribbon/spiral reactors. These reactors are usually heated with steam and hot-gas jackets or direct contact with steam and hot gas directed into the reactor vessel. In the case of lime and cement production (rotary kiln), iron making (open hearth), and glass production (floated ribbon surface), very high temperatures are realized with *in-situ*/over-fire combustion, exploiting radiation and convective heat transfer to decompose the solid material or to burn out impurities. Reactant feed streams are often preheated using a jacket heat exchanger that recuperates heat from the effluent gases and solid products.

Thermodynamic efficiency and kinetic considerations typically require plant operation at high temperatures to achieve high production rates and to reduce plant size. For any chemical reaction to occur, its change in Gibbs free energy, ΔG, in going from reactants to products must be negative, where higher conversion efficiency is achieved as ΔG becomes more negative. This quantity is defined as:

$$\Delta G = \Delta H - T\Delta S$$

where ΔH is the change in enthalpy, T is temperature, and ΔS is the change in entropy. For most reactions, a negative ΔG is obtained by having a negative ΔH. Reactions that require heat addition have a positive ΔH and by convention are referred to as being endothermic. In that situation, to obtain the negative ΔG that allows a reaction to proceed, ΔS must be positive. In most cases, a positive ΔS is a consequence of larger molecules being broken down into several smaller ones (for instance, the conversion of methane and water into a mixture of carbon monoxide and hydrogen molecules). Synthesizing more complex molecules from simple feeds generally has a negative entropy change. Even when the entropy change is positive, ΔS is usually small, so the absolute temperature T must be large in order to promote the desired reaction.

About 40% of energy delivered to conventional chemical plants is by steam loops (DOE 2016a), where steam is produced and superheated by a package/combustion-fired/tube boiler or by hot gases that are produced by combustion, including the combustor effluent itself or a heating coil if an inert gas or an intended reactant gas is required. Although the amount of steam needed varies greatly depending on the process, its magnitude can usually be estimated. For example, the heat required to boil octane, a typical organic compound of petroleum distillate, is about 300 kJ/kg (130 Btu/lb). Assuming that the process streams pass through five distillation steps, each with a reflux ratio of five,[18] a total of 2.6 MJ/kg (5,400 Btu/lb) of heat is required to fractionate petroleum feed into its respective distillate fractions. Regardless of the heat demand in the primary organic synthesis reaction(s), separation and purification of the reaction products can also consume a large amount of heat as steam.

The low cost and high volume/energy density of fossil fuels has been a major factor in the design of almost all conventional industrial processes. Replacement of combustion gases with a clean heat source or electrification of the process-unit operations, in combination with substitution of fossil fuels with hydrogen produced by nuclear and renewable energy sources, can accelerate deep reduction of CO_2 emissions.

In practice, the temperatures of reactions that absorb heat such as dehydrogenation of butylenes to butadiene (600–800°C), steam methane reforming (800–900°C), or lime production (900–1,200°C) are well above the heat level that is available from light-water reactors and are above most high-temperature nuclear-reactor operating temperatures (Pitzer 1972; Wood 2010; Eggeman 2010a). For example, future high-temperature reactors under development within the GEN IV nuclear reactor program may reach temperatures between 550ºC and 1,000ºC and could be used to provide heat to some of the higher-temperature industrial processes (Locatelli 2013). Therefore, new heat-integration schemes, including topping heat, can enable full advantage of nuclear heat sources. Understanding the selection and optimization of heat-exchange processes is important to understanding how to effectively integrate clean heat sources within existing plant designs. In practice, determining options for heat integration is supported by exergy destruction analysis, which can be understood through matching composite stream temperature-enthalpy curves and performing pinch analysis to design heat-exchanger networks for a given plant (Hewitt et al. 1994).

3.2 Assessment of Industry Thermal Energy Use

The appendices to this report provide detailed material and energy-use rates for major process plants representing each key industry among each of these sectors. Although the selected plants represent only one-fourth of the U.S. industrial energy use (5,823 PJ [5,520 TBtu] total), they are representative of the majority of Chemicals, Petroleum Refining, Forest Products, Food and Beverage, Iron & Steel, and Remaining Manufacturing industries. Table 7 identifies the total number of plants for each of these categories, the total energy usage for all plants, average plant energy-use rates, and thermal characteristics. Actual plant sizes can vary by a factor of 2–5 times the average plant size.

Table 7 and Table 8 summarize data for selected industries. Table 7 is based on the number of plants reporting combustion GHG emissions to the GHGRP and their total production and emissions. Table 8 summarizes data gathered from a variety of sources including process flow sheets, detailed process descriptions, publications, and technical references. Detailed data for each selected process can be found in the appendices. The data were normalized based on the average plant combustion GHG emissions reported for each target industry, as summarized in

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[18] Reflux ratio is the amount of condensed overhead product returned to the column to be re-vaporized to increase the distillation performance expressed as a multiple of the amount removed as product.

Section 2. As a result of this normalization, the data in Table 7 and Table 8 may not match the data presented in the appendices for a particular industry or typical average facility.

Table 7. Production and Emissions of Selected Industries Based on Sum Total of Facilities Reporting Combustion GHG Emissions[19]

Industry Subsector	Target Industry	Production (tonnes/day)	Number of Plants	Electricity Use (MW)	Heat Input in TJ/day (TBtu/day)	Emissions (tonnes CO_2e/day)
Petroleum and Coal Products	Petroleum Refineries	**Production (bpd/day)**	141	2,558	1,160 (1.099)	339,493
	Gasoline	4,769,807				
	Diesel	1,797,319				
	Kerosene	952,425				
Primary Metal Manufacturing	Iron and Steel Mills	69,345	115	14.1	278 (0.264)	139,630
Paper Manufacturing	Paper and Paper-Board Mills			4,556	1,793 (1.699)	
	Paper	199,845	116			87,611
	Paper-Board	323,200	73			65,708
	Pulp Mills	14,223	30		129 (0.122)	32,854
Chemical Manufacturing	All Other Basic Chemical Manufacturing (Methanol)	229,677	85	2,040	1,096 (1.039)	57,495
	Ethyl Alcohol Manufacturing	10,695	168	-266	297 (0.282)	49,281
	Plastics Material and Resin Manufacturing	114,557	72	2,090	764 (0.724)	46,324
	Petrochemical Manufacturing (Ethylene)	93,268	35	2,465	82.9 (0.0786)	43,806
	Alkalies and Chlorine Manufacturing		11	2,492	47.0 (0.0445)	35,592
	Chlorine	14,633			0.177 (0.000168)	
	Sodium Hydroxide	12,777			46.7 (0.0443)	

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[19] Data in table normalized to industry combustion GHG emissions reported to EPA GHGRP in 2014.

Industry Subsector	Target Industry	Production (tonnes/day)	Number of Plants	Electricity Use (MW)	Heat Input in TJ/day (TBtu/day)	Emissions (tonnes CO_2e/day)
	Nitrogenous Fertilizer Manufacturing (Ammonia)	22,723	30	812	211 (0.200)	21,903
Food Manufacturing	Wet Corn Milling		24	314	193 (0.183)	49,281
	Starch	35,063				
	Corn Gluten Feed	14,243				
	Corn Gluten Meal	3,289				
	Corn Oil	2,200				
Nonmetallic Mineral Product Manufacturing	Lime & Cement					
	Lime	24,863	49	62.6	149 (0.141)	27,379
	Cement	234,000	117	1,615	1,100 (1.04)	444,600
Mining (Except Oil and Gas)	Soda Ash	58,003	11	106	286 (0.271)	16,427

bpd = barrels per day

Table 8. Production and Emissions from Average Plant of Selected Industries[20]

Industry Subsector	Target Industry	Production (tonnes/day)	Electricity (MW)	Heat Use in TJ/day (MMBtu/day)	Emissions (tonnes CO_2e/day)	Process Heat Type/ Purpose	Chemical Process	Process Heat Temperature (ºC)
Petroleum and Coal Products	Petroleum Refineries	**Production (bpd/day)**	18.1	8.23 (7,800)	2,408	Gases from fired heater/ atmospheric crude fractionator and heavy naphtha reformer	Continuous	600
	Gasoline	33,828						
	Diesel	12,747						

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[20] Data in table normalized to industry combustion GHG emissions reported to EPA GHGRP in 2014.

Industry Subsector	Target Industry	Production (tonnes/day)	Electricity (MW)	Heat Use in TJ/day (MMBtu/day)	Emissions (tonnes CO_2e/day)	Process Heat Type/ Purpose	Chemical Process	Process Heat Temperature (ºC)
	Kerosene	6,755						
Primary Metal Manufacturing	Iron and Steel Mills	603	0.123	2.42 (2,290)	1,214	Combustion products/coke production/iron ore reduction	Batch charge	1,100
Paper Manufacturing	Paper and Paper-Board Mills		53.6	21.1 (20,000)		Steam/drying	Continuous	177
	Paper	1,723			755			
	Paper-Board	4,427			900			
	Pulp Mills	474		4.32 (4,100)	1,095	(90% CHP with in-plant black-liquor recovery furnace)		
				0.67 (640)		Combustion gases from black liquor and waste wood/lime kiln	Continuous	800
				1.15 (1,090)		Steam/heat to digester, bleaching, oxygen stage, multi-effect evaporator, chemical preparation	Batch	200
				2.56 (2,43)		Steam/pulp machine, multi-effect evaporator, chemical preparation	Continuous	150
Chemical Manufacturing	All Other Basic Chemical Manufacturing (Methanol)	2,702	24.0	12.9 (12,300)	676	Indirect heat from combustion gases/ primary reformer; steam/ methanol distillation	Continuous	900
	Ethyl Alcohol Manufacturing	63.7	-1.58	1.76 (1,670)	293	(In plant biomass residue furnace CHP) steam/ pretreatment and conditioning	Continuous or batch	266

Industry Subsector	Target Industry	Production (tonnes/day)	Electricity (MW)	Heat Use in TJ/day (MMBtu/day)	Emissions (tonnes CO_2e/day)	Process Heat Type/ Purpose	Chemical Process	Process Heat Temperature (ºC)
						Steam/distillation	Continuous or batch	233
						Steam/power production	Continuous or batch	454
	Plastics Material and Resin Manufacturing	1,591	29.0	10.6 (10,061)	643	Steam/distillation	Continuous	291
	Petrochemical Manufacturing (Ethylene)	2,665	70.4	2.37 (2,250)	1,252	Indirect heat from combustion gases/cracking furnace	Continuous	875
	Alkalies and Chlorine Manufacturing		227	4.27 (4,050)	3,236	(50%–75% CHP)		
	Chlorine	1,330		0.0161 (15.3)		Steam/drying and heating of brine	Continuous	177
	Sodium Hydroxide	1,162		4.24 (4,020)		Steam/drying	Continuous	177
	Nitrogenous Fertilizer Manufacturing (Ammonia)	757	27.1	7.03 (6,660)	730	Indirect heat from combustion products/primary steam reformer	Continuous	850
Food Manufacturing	Wet Corn Milling		13.1	8.06 (7,640)	2,053			
	Starch	1,461				Steam/steeping	Batch	50
	Corn Gluten Feed	593						
	Corn Gluten Meal	137				Steam/drying	Continuous	177
	Corn Oil	92						
Nonmetallic	Lime and							

Industry Subsector	Target Industry	Production (tonnes/day)	Electricity (MW)	Heat Use in TJ/day (MMBtu/day)	Emissions (tonnes CO_2e/day)	Process Heat Type/ Purpose	Chemical Process	Process Heat Temperature (ºC)
Mineral Product Manufacturing	Cement							
	Lime	507	1.28	3.05 (2,890)	559	Combustion gases/heating kiln	Continuous	1,500
	Cement	2,000	13.8	9.4 (8,900)	3,800	Combustion gases/heating kiln	Continuous	1,200
Mining (Except Oil and Gas)	Potash, Soda, and Borate Mining	5,273	9.62	26.0 (25,00)	1,493	Steam/calciner, crystallizer, and dryer	Continuous	300

3.3 Petroleum and Coal Products Manufacturing—Petroleum Refineries

The petroleum refining industry is the second-largest consumer of energy (Appendix C). Over the past decade, roughly 7% of the total U.S. energy demand was from oil refineries. As of January 2016, there were 111 operating refineries, with a capacity of 15.3 million barrels per stream day (bpd) crude distillation (EIA 2016). The average plant size was 138,000 bpd, ranging in size from 3,400 bpd to 584,000 bpd (Figure 16).

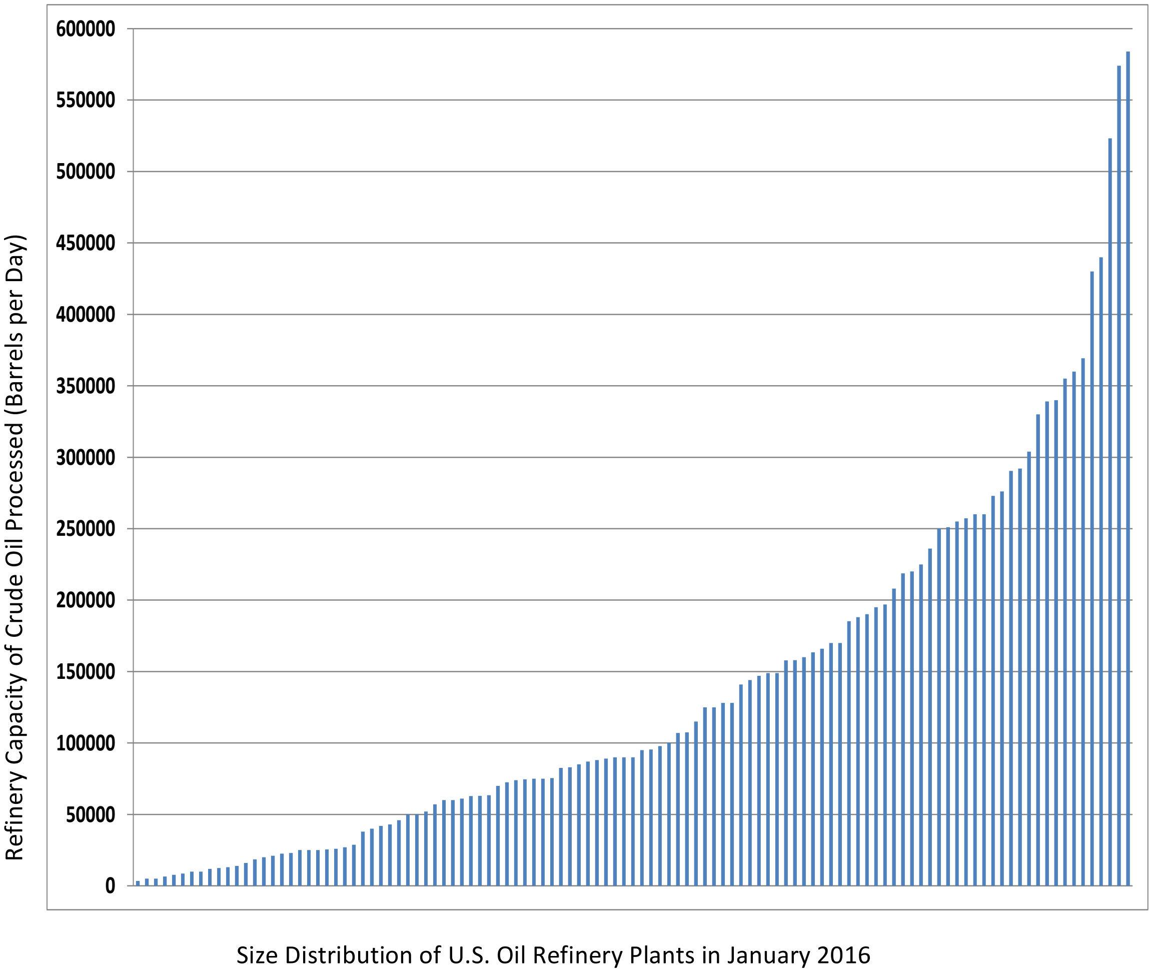

Figure 16. U.S. refinery operating capacity in barrels per stream day, as of January 2016

Data source: EIA (2016)

Older refineries can consume up to 15%–20% of the energy value of their feedstock for supplying process heat, although modern refineries average closer to 6% and use almost entirely natural gas feedstock or refinery fuel gas to produce the required heat (Ingersoll et al. 2014). Energy in the form of steam, electricity, or direct-fired heat is used in each of the refineries, where the total energy requirement for the average plant is 138,000 bpd using about 900 GJ (853 MMBtu) net thermal energy. The demand can range up to 3.6 TJ (3,400 MMBtu) net thermal energy for the largest plant.

In addition to the thermal loads, the average refinery consumes about 100 tonnes of hydrogen each day. About one-half of this hydrogen is produced internally with tail gases. The other half is provided by an external supply (Slone and Gerdes 2008; EPA 2012).

An SMR can conveniently produce the steam and energy required by a petroleum refinery. The crude can be preheated prior to its input into the crude fractionator. Nearly all of the natural gas (about 300 tonnes per day for the average plant of 138,000 bpd) that is used to generate steam in a package-tube boiler can be eliminated with an external heat source—particularly when hot gases from a high-temperature SMR are provided to produce high-pressure steam at 600°C. A recent study revealed that one NuScale Power Module, a pressurized-water reactor (PWR) rated at 160-MW net thermal energy can optimally provide the heat and electricity needed to produce 1,310 kg/h hydrogen and 10,400 kg/h oxygen using one matched-scale, high-temperature water electrolysis module (Ingersoll et al. 2014). Based on this study, about 387 MW_t energy (net) from this type of SMR technology could be used to produce the approximately 75 tonnes of hydrogen that is currently supplied by merchant sources. For the largest petroleum refineries, the duty rises to 3–4 times this amount, approaching 1,500 MW net thermal demand for hydrogen production.

Most unit operations in a petroleum refinery are set up to operate continuously; however, some units can be started up and run independently if tank storage is sufficient to provide hold-up for intermediate products. Most refineries are set up to process specific grades of crude. Product lines are separated into several streams and each stream is formulated on the basis of seasonal fuel specifications that are met by combining stream fractions that can vary.

Heat supply to refineries is usually approximately constant. However, because a large portion of heat is produced with natural gas from an outside supplier, natural-gas-fired steam boilers or fired heaters could be modulated with variable supply of clean heat.

In summary, a large reduction in emissions could be achieved if the refinery industry uses clean-source thermal/electrical energy. Economies of scale are likely to limit the proposition to refineries with a net crude stream rate of 50,000 bpd, which could use about 130 MW net thermal output for co-generation of steam, electricity, and hydrogen (see Appendix C).

3.4 Primary Metal Manufacturing—Iron and Steel Mills

The U.S. iron and steel industry is a shadow of its capacity prior to 1980. At its peak raw steel production in 1974, the United States accounted for 20% of global production but accounted for only 5% in 2013 (USGS 2015). However, U.S. steel production still accounts for at least 5% of the total energy use by industry and about 3% of the industrial-sector CO_2 emissions (Table 2). The emissions come primarily from traditional blast furnace and either a basic oxygen furnace or open hearth that use coke and natural gas, respectively, to recover and purify the iron from iron ore. In the blast furnace, combustion of partial oxidation (i.e., gasification) of the metallurgical-grade coke slowly brings the smelt up to 1,700°C. Carbon monoxide (CO) reduces the iron oxide to molten elemental iron. The molten metal is refined and purified in the basic oxygen furnace at around 1,600–1,650°C to produce castable or ductile iron metal (Elshennawy and Weheba 2015; EPA 2012; Eggeman 2010b). Metals annealing and rolling requires additional heat, which is typically supplied by *in-situ* natural gas burning.

Scrap-metal recycling plants now produce about one-half of all U.S. steel in electric-arc furnaces. The quality of this steel is inferior to steel that is produced from raw ore because the contaminant and metals mixtures that come to the plant at any given time.

A technical review of the steel manufacturing process steps reveals few, if any, opportunities for direct substitute clean heat sources to iron and steel making process unit operations (Appendix D). The up-front unit operation heat loads for the steel industry are very difficult to replace because combustion gases also participate in chemical redox reactions or radiant heat transfer. Hydrogen is an alternative reducing agent for iron ore. Reduction takes place faster (10x) than CO at temperatures above 800°C, but heat has to be supplied because the reaction is endothermic.

$2Fe_2O_3 + 3C \rightarrow 4Fe + 3CO_2$	Blast Furnace Coke Reaction
$2Fe_2O_3 + 6CO \rightarrow 4Fe + 6CO_2$	Direct Reduction by CO
$2Fe_2O_3 + 6H_2 \rightarrow 4Fe + 6H_2O$	Direct Reduction by H_2

Some advances have been made on the subject of direct reduction of iron with hydrogen,[21] and it has been estimated that hydrogen-based steel making could reduce total CO_2 emissions from steel production by 80% (Fischedick et al. 2014b). However, there are currently no commercial plants that exclusively use hydrogen to produce iron and steel.

The front end of steel mills generally operates in a batch manner, with charges of iron ore, coke, and limestone being charged at once to the blast furnace. The electric-arc furnace can be operated in a batch or semi-batch mode. The back end of the steel-making process is generally operated in a continuous mode. Provisions for intermittent clean heat can be established in case an external clean energy source is available on an intermittent basis.

3.5 Paper Manufacturing—Paper, Paperboard, and Pulp Mills

Although paper, paperboard, and pulp mills represent the third-largest consumer of energy in the United States, more than two-thirds (~70%) of the raw energy used is steam duties that are principally used for concentrating and drying materials. The "hog fuel" composed of bark, limbs, and sawdust is burned to produce superheated steam for electricity generation and process heating in pulp production. Kraft pulp mills also burn black liquor (a mixture of oily lignin and sodium hydroxide caustic) in a boiler to recover the sodium for recycling (see Appendix E and Appendix F). Consequently, the pulp and paper industry in aggregate could be considered net-zero carbon in many cases, using CHP to produce the steam and electrical loads of the plant. Stand-alone pulp mills produce excess power, whereas stand-alone paper and paperboard mills use roughly 21 TJ (20,000 MMBtu) energy and 54 MW electricity.

Until alternative markets are developed for black liquor, the pulp industry is unlikely to benefit from additional clean energy sources. Paper and paperboard mills, on the other hand, use a

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[21] As an example, the ENERGIRON process converts iron ore pellets or lumps into metallic iron with a counter-current flow of very hot (950–1,100°C) reducing gases that include hydrogen at high pressure (6–8 bar).

variety of heat levels to concentrate and dry pulp once it has been solubilized and sprayed onto drum rollers for drying. The drying process is operated on a semi-batch basis where specific products are produced on a "campaign basis." Variable supply of clean heat, on the order of 5–10 MW_t, can be mixed with the steam supply or combustion gas effluent that are used to concentrate the pulp and to dry the paper, respectively. With the addition of the externally produced steam or hot gas (i.e., heated air), plant steam generation and gas-fired burners can be rapidly modulated in correspondence with the external heat source.

3.6 Chemical Manufacturing

Within the chemicals industry, this report highlights four processes that represent the vast number and variety of organic chemical, inorganic minerals, ammonia, and synthetic polymer industries. The intent, of course, is to understand the opportunity to replace CO_2 emissions-producing sources with zero-emissions heat and electricity.

3.6.1 All Other Basic Organic Chemical Manufacturing (Methanol)

We chose methanol production as a surrogate for the All Other Basic Organic Chemicals Industry because it involves a common step of steam reformation that requires heat. Steam reformation is followed by a tubular synthesis reactor that produces methanol while removing heat generated by the reactions. The unconverted reactants are separated from the products using a condenser for recycle back to the reactor. Gentle evaporation then purifies the product (see Appendix G).

Methanol is one of the predominant commodity chemicals in the United States and around the world. It is a feedstock to produce chemicals, such as acetic acid and formaldehyde, which in turn are used in products such as adhesives, foams, plywood subfloors, solvents, and windshield washer fluid. In recent years, the use of methanol in the production of olefins, or methanol-to-olefins, has grown rapidly (Alvarado 2016). Methanol can also be used on its own as a vehicle fuel or blended directly into gasoline to produce a high-octane, efficient fuel with lower emissions than conventional gasoline. Methanol is a key reactant for making biodiesel, and it can be dehydrated to produce dimethyl ether—also a clean-burning fuel with properties similar to propane. There has been constant interest in converting synthetic gasoline derived from natural gas and coal into motor gasoline using a process pioneered by ExxonMobil referred to as methanol-to-gasoline. However, the low price of petroleum fuels may impede commercialization of this process, except in China, where a commercial demonstration is in operation (Khalil 2015).

There are at least two opportunities to replace natural gas combustion in methanol production: one is the heat needed for the primary reformer, and the second is the heat required for methanol purification. The former case is illustrated in Figure 17. It is feasible to replace the hot combustion gases with a flameless hot gas produced by an external source that is hotter than 740°C to effectively heat the primary reformer and to preheat the natural gas feed. About 12.9 TJ/day (12,300 MMBtu/day) of energy is required for the average-size methanol plant.

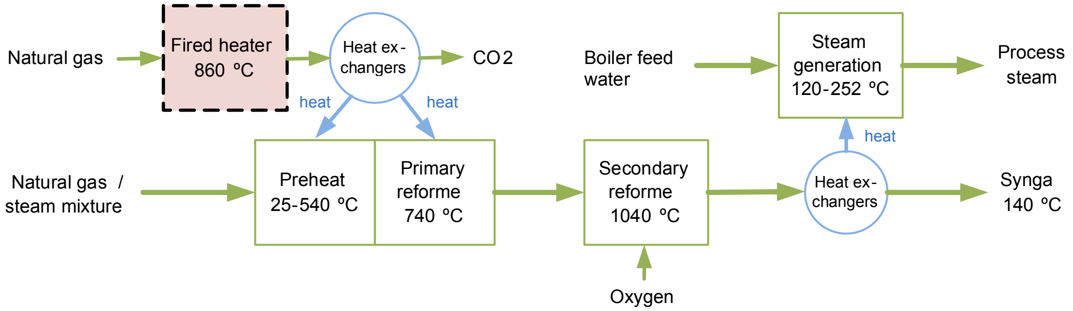

Figure 17. Energy use in synthetic gasoline production for use in methanol synthesis

High-temperature nuclear reactors (either molten salt or high-temperature gas-cooled reactors) and solar industrial process heat (SIPH) plants are capable of supplying this level of heat directly. Opportunities to use lower-temperature heat sources are discussed in the following section but have limited impact on CO_2 reduction unless the methanol production plant is redesigned to implement a new heat-integration scheme.

Methanol can also be produced by hydrogenation of CO_2. Although this reaction is less efficient than the conventional process, it does provide a route for CO_2 capture and use with hydrogen produced by clean energy sources. The economic feasibility of this process route depends on the cost of natural gas, production cost of clean energy, and clean-energy production credits in the future.

The steam reforming process at the front end of a methanol plant is designed to operate continuously to avoid thermal cycling of catalysts. Methanol plants take 1–2 days to start up and 2–3 days to shut down to avoid thermal shock. However, an intermittent hot-gas source could be blended with the combustion effluent of a natural gas burner to reduce CO_2 emissions proportional to the mass flow of the external heat source. In this case, hot helium circulation is unlikely to be practical; rather, a recycle loop of the natural gas burner exhaust could be used to transfer heat from the external heat source.

A variable external supply of heat (3–5 megawatt-electric [MWe]) can be used for methanol purification in the down-stream unit operations of the plant.

3.6.2 Ethyl Alcohol Manufacturing

The United States produced about 50 billion liters of ethanol for consumption and about 56 billion liters of gasoline additive in 2016, according to resources listed in Appendix H. Most current production is from corn grain using either a dry milling process (that converts grain to ethanol directly) or a wet milling process that is also used to produce starches and other food products. The wet milling process is discussed in Section 3.7.

Research and development is underway to convert lignocellulosic biomass to ethanol (Eggeman 2010c). In one of the typical processes under development, lignocellulosic biomass is converted through enzymatic hydrolysis and fermentation of hydrolysate produced from biomass. Byproduct lignin, unconverted cellulose, biomass sludge, and biogas from a wastewater anaerobic digester can be burned to produce the steam and power that is required by the plant processes. External combustion fuel is mainly used to help burn the biomass residue combustibles. Overall, enough steam is produced to meet the plant’s steam and electricity needs and generate excess power, which can be sold to the grid. Consequently, there would be no purpose to replace the combustion fuel, unless an alternative use of the byproducts is developed. Because the emissions are a derivative of the combustion of biomass, the process is often considered to be low-GHG emitting in the long term as long as new biomass is grown to replace the combusted biomass. Emissions from growing and harvesting biomass crops with fossil-based energy, production and application of chemicals (fertilizer and pesticides), and changes in land cover or management will still occur and increase atmospheric CO_2 concentrations (Bracmort 2016).

3.6.3 Plastics Material and Resin Manufacturing (Polyethylene and Polyethylene Terephthalate)

A cursory assessment of the plastics and resin market was completed as documented in Appendix I. World plastics annual production rose from around 200 million tonnes in 2000 to 300 million tonnes by 2013 (PlasticsEurope 2015). According to these same statistics, North America[22] and Europe's annual output of thermoplastics and polyurethanes averaged around 50 million tonnes, with about 10 million tonnes of polycarbonate, Teflon™, and other niche plastic products. However, the advent of low-cost natural gas is currently motivating a strong upswing in U.S. plastics production (EIA 2014).

Polyethylene (PE) and polyethylene terephthalate (PET) are representative chemical proxies for the plastics and resins manufacturing industry. Together, PE and PET are a significant fraction of annual U.S. market share of plastics and resins. Ethylene is the building block for PE, and it is identified in this report as a proxy for petrochemical manufacturing (Appendix J). Ethylene, para-xylene, and acetic acid are the basic building blocks for PET, where ethylene glycol and purified terephthalic acid are intermediate chemicals that can either be produced on site or purchased from the chemical commodities market.

A fully integrated PET plant with a typical average plant size of 500,000 tonnes per year (1,369 tonnes per day) requires about 25 MWe and 9.0 TJ/day (8,530 MMBtu/day) to support the plant electrical and thermal duties. Heat is mainly supplied by steam at 300°C or less.

In summary, plants that produce PE and PET plastics are not candidates for SMR reactors. Nuclear reactors can provide heat and power to PET plants, but the current market could deploy about six to eight 150-MW_t, SMR reactors. The remaining niche plastics and resins market could utilize SMR reactors, although this has not been verified by this study.

3.6.4 Petrochemical Manufacturing (Ethylene)

Ethylene production in the United States nearly matches the production rates and energy demand of methanol. About 60% of annual ethylene production is used to produce polyethylene (Figure 18), a popular thermoplastic commodity used in consumer products (especially products created

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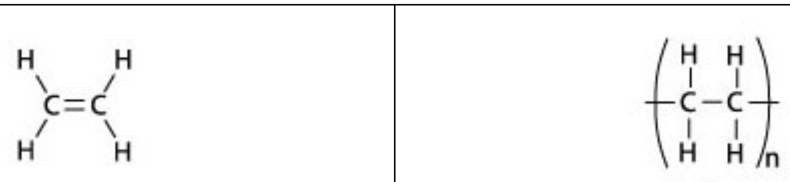
[22] North America encompasses countries subscribed to the North American Free Trade Agreement (NAFTA).

by rotational molding).[23] The remaining 40% of annual ethylene production is used to produce ethylene glycol, vinyl chloride, styrene, and detergent alcohols, among other chemicals.



Ethylene

Polyethylene Polymer

Figure 18. Molecular diagram for ethylene and polyethylene polymer

The most common process for producing ethylene is to scission naphtha or other petroleum gases in a cracking furnace that operates at temperatures ranging from 750°C to 875°C. Appendix J reveals that the main, if not only, opportunity to use a clean heat source is within this furnace. However, because the heat duty of about 50 TJ/day (47,000 MMBtu/day) is mainly achieved by combustion of pyrolysis oil byproduct, a typical plant only requires about 2.4 TJ/day (2,250 MMBtu/day) of additional fuel. An SMR is probably an impractical candidate for a stand-alone plant, unless steam and electricity (about 65 MWe) demands are met by an SMR that sends all other power generation to the grid. A concentrating solar unit that is capable of providing hot gases at about 900–1,000°C may be a reasonable match or a thermal energy storage battery that can generate a hot gas at temperatures comparable to combustion effluent.

Ethylene plants are best operated at a constant rate. However, an intermittent clean-energy steam supply can reduce the steam duties currently met with a natural-gas boiler. A steam accumulator could increase use percentage of the clean energy source.

3.6.5 Alkalies and Chlorine Manufacturing

The chlor-alkali industry represents a wide class of electrochemical processes in the United States that consume a large fraction of the electricity used by the process industry. Thermal energy is mainly required for evaporation and concentration of the two products made from decomposing salt (NaCl): sodium hydroxide and chlorine gas (Appendix K). Therefore, nearly all of the thermal energy required—about 4.27 TJ/day (4,050 MMBtu/day)—is used to produce steam. This amount could be readily tapped from an SMR that primarily produces electricity for the plant duty of about 227 MWe for the plant electrolyzer and other loads. A concentrating solar unit that is used to generate low-pressure steam is likely to be sufficient to eliminate combustion-fired steam generation at the plant. Thermal energy storage reservoirs that are designed to continuously generate steam on demand are also a candidate for a zero carbon-emissions, thermal energy source.

The electrolysis (diaphragm cell) of chlor-alkali plants is best operated at a constant rate to maintain stream concentrations in the electrolysis cell. However, all down-stream concentrating and drying unit operations can be operated in an intermittent pattern, provided that holding tanks

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[23] For more information on rotational modeling, see http://www.plasticmoulding.ca/techniques/rotational_moulding.htm.

have sufficient capacity and that the solutions are held at temperatures sufficient to avoid crystallization in the holding tanks and/or reactors. A steam accumulator could increase the use percentage of a clean energy source by helping maintain continuous flow/operations of all unit operations.

3.6.6 Nitrogenous Fertilizer Manufacturing (Ammonia and Derivatives)

During 2015, 30 plants produced 9.4 million tonnes of ammonia (NH_3) (Appendix L), principally based on the Haber-Bosch reaction processes. The principal feedstock to these plants is natural gas, which is reformed with steam to produce a target stoichiometric gas mixture of CO_2, N_2, and H_2. Sorbents are used to remove CO_2 and other contaminants prior to synthesizing NH_3. Ammonia is used to produce a wide variety of fertilizers, nitric acid, and amine-based chemicals.

Clean heat at temperatures of at least 800°C can be used to reduce the combustion of natural gas in the first stage of a conventional steam-methane reforming-based ammonia plant (Wood 2010). Alternatively, hydrogen can be produced with low-temperature proton-exchange membrane (PEM) electrolysis or high-temperature steam electrolysis, with nitrogen optimally obtained by cryogenic air-separation units and refrigeration units powered by electricity. In this case, the clean energy source is mainly electricity. Technical and economic assessments of ammonia or ammonia derivatives production with high-temperature SMRs were recently completed by the Next Generation Nuclear Plant Industry Alliance (Wood 2010). The assessments conclude that the ammonia industry is suitable for re-invention with transformative hydrogen-generation technologies. Incentives to reduce CO_2 emissions could stimulate this change in the very near future.

The steam-reforming process at the front end of a conventional ammonia plant is designed to operate continuously to avoid thermal cycling of catalysts. Each of the 30 plants consumes about 7.03 TJ/day (6,600 MMBtu/day). A constant external heat source is needed to effectively displace the heating in the primary reformer. However, an intermittent hot-gas source could be blended with the combustion effluent of a natural gas burner to reduce CO_2 emissions proportional to the mass flow of the external heat source. In this case, hot helium circulation would not be practical; rather, a recycle loop of the natural gas burner exhaust could be used to transfer heat from the external heat source.

3.7 Food Manufacturing—Wet Corn Milling

The wet corn milling industry as a whole consumes more energy than any other class of food manufacturing. The detailed plant discussion in Appendix M reveals that an average plant (processing 100,000 bushels per day) consumes about 8 TJ/day of heat for steeping corn grain and processing in order to obtain corn oil, fiber, and starch products and 13.1 MWe of electricity is consumed for grinding and milling operation, respectively.

A small solar boiler fed from a SIPH solar field could readily replace fossil-fired boilers in many food processes industries. Energy storage could provide constant steam supply, unless a back-up fossil-fired boiler is on standby. Seasonal operation and demand profiles for some food processing are additional considerations to take into account depending on the type of food that is processed. For example, tomatoes and other vegetables that can spoil in a matter of days or weeks must be processed during the season they are produced. Potatoes, on the other hand, as well as grains, can be stored and processed on a near steady rate.

A steam accumulator can be used to provide steam duties as they are needed for the various unit operations. Some of the unit operations can also be operated in batch-mode provided that holder tanks are added to the process sequences.

3.8 Nonmetallic Mineral Product Manufacturing—Lime and Cement Manufacturing

Lime and cement production is one of the major industry CO_2 emitters because of the energy intensity and high heating levels required to reduce limestone, silicates, and clays into calcium oxide and pozzolan admixtures, which are used to produce bricks, mortar, and Portland cement. Over-fire combustion with direct contact of the mineral solids is needed to achieve the thermal heat rates and peak temperatures of 1,200°C and 1,500°C necessary for lime and cement production, respectively (see Appendix N). Only an electric arc or plasma torch can achieve these same thermal levels, but they may not be able to affect the same chemistry and also avoid melting and vitrification of the mineral feeds.

Hydrogen enrichment of the natural-gas-fired burners and the use of biomass char and/or biogas may be the best method of reducing the life-cycle emissions of lime and cement production. Even CO_2 capture is a difficult proposition for these processes because of the mass and relatively dilute concentration of the flue gas. However, oxy-firing could improve the technical feasibility of carbon capture for kiln operations.

3.9 Mining (Except Oil and Gas)—Soda Ash, Potash, and Borate Mineral Mining

Although the soda ash, potash, and borate mineral mining industry has few plants (11 total reporting to the EPA GHGRP), an individual plant consumes on average 150 MWt of heat and a total of 299 MWt CHP. In the case of soda ash, four plants are located in close proximity in southwest Wyoming, where trona mineral is abundant.

Trona is a naturally occurring mineral sodium sesquicarbonate [$Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$]. Trona processing to make soda ash (or sodium carbonate [Na_2CO_3]) entails converting the sodium bicarbonate ($NaHCO_3$) into carbonate, then removing the clay and iron contaminants by recrystallizing the sodium carbonate. After mining and crushing, the trona ore is calcined at about 250ºC to drive off the water that hydrates the sesquicarbonate crystal and to drive the reaction:

$$2\ NaHCO_3 \rightarrow Na_2CO_3 + H_2O + CO_2$$

The sodium carbonate is dissolved in water, leaving behind insoluble clays and iron compounds to be physically separated from the sodium carbonate solution. Residual organic contaminants in the trona are adsorbed onto activated carbon to improve crystal formation as water evaporates to concentrate the solution, causing crystals to form. A facility producing 2,740 tonnes/day of soda ash—the scale of each one of the four plants near Green River, Wyoming—uses an estimated total of 13.5 TJ/day (12,800 TBtu/day) and 5 MWe for a total CHP thermal energy load of about

161 MW_t of heat (see Appendix O). Four plants combined require about 625 MW_t. This represents a unique case where a cluster of plants already exists.

The total demand, heat quality (mostly steam), and proximity of the four plants in Wyoming could provide a favorable opportunity to replace fossil-fired steam boilers with a nuclear-based heat source. Other stand-alone plants of this variety may be candidates if economies of scale are favorable—that is, when the cost of building and operating an SMR or a SIPH facility is comparable to the costs of fossil-fuel package-tube boilers. In either case, assessment of specifics such as solar radiation and availability of the land needed for an SMR would improve understanding.

Minerals processing is carried out in a semi-batch mode. Steam supply from an external source could use a steam accumulator to accommodate intermittent generation of heat. Any amount of steam supplied from the external heat source could proportionally reduce steam that is generated by a fossil-fuel-fired steam boiler.

4 Alternative Heat Supplies and Heat Transport

Replacement of in-plant heat generation with a flameless heat source provided by a nuclear reactor or SIPH system begins with:

1. Assessing the size and dependability of the external heat source
2. Assessing the heat-transport distance and distribution of the thermal working fluid (and return in a closed system)
3. Selecting an appropriate heat-transfer medium
4. Evaluating existing or new heat exchangers and heat transfer into reaction processes
5. Preventing fugitive radiological contamination.

The previous section shows that individual oil refineries, iron- and steel-making plants, cement/lime plants, and some large chemical plants (e.g., methanol, ammonia, and soda ash) have comparably large heat duties and electricity demands, which potentially could be met with an SMR (10–300 MWe) (Todreas 2015). Many processes require low-quality steam under the critical point, up to temperatures of 350°C and at moderate pressure up to about 2 megapascals (MPa). Steam temperatures up to 600°C are used for petroleum refining. Higher-temperature steam up to 600–650°C and 15–20 MPa is most often used as a flow motive in steam turbines that generate electrical power. Stainless-steel piping is required at these pressures and temperatures. Even higher-temperature/high-pressure steam, often referred to as ultra-supercritical steam (up to about 760°C and 35 MPa), could be produced by advanced power systems. Nickel-metal alloys are necessary for steam generation and transport under these conditions. A review of power generation options for electricity is a useful guide for matching thermal duties that could theoretically be supplied by harvesting the steam normally supplied to the power generators (ORNL 2012).

Steam-methane reforming, the basic unit operation to produce methanol, or in combination with the water-gas-shift reaction to produce hydrogen, requires heat (as hot combustion gas) exceeding 750°C (for methanol syngas feed) and 800°C for hydrogen. This may be supplied by a high-temperature salt or a high-temperature helium gas, which can only be attained with a high-temperature nuclear reactor or CSP.

High-temperature helium systems operating at temperatures up to 750°C have been qualified by the Nuclear Regulatory Commission for nuclear plants. Operations above this temperature require American Society of Mechanical Engineers code qualification. The Next Generation Nuclear Plant (NGNP) Program has made progress in alloys for helium systems to operate at temperatures approaching 950°C (Next Generation Nuclear Plant Project 2011). If this work is completed, direct heat delivery for the chemical industry may be valuable.

In the case of very high-temperature unit operations such as lime and cement making, it is possible to burn biomass or hydrogen that is generated by nuclear and renewable energy processes to attain the temperature necessary to calcine or smelt minerals and ores.

Electrical heating can be used to replace combustion systems. But in most cases, this will require new chemical-process reactor designs, whereas steam and hot-gas substitution can more readily replace the chemical-process reactor heater.

In the case of smaller plants, economies of scale may require a cooperating cluster of plants—an energy park (EP)—to take advantage of a single, large heat supplier.

Finally, most of the pulp and paper mills and ethyl alcohol plants may be considered net-zero carbon according to the view that they mainly combust biomass or biomass residues. However, the concept of an EP may also be relevant for GHG mitigation in other sectors if the biomass residues can be converted into a chemical feedstock or fuels for processes that require high temperatures. For example, gasification of the biomass residues can provide synthetic gasoline for chemical synthesis, or the residues may be burned as fuel for cement and steel making. Therefore, use of multi-energy (ME) sources can also be considered when replacing fossil fuels.

4.1 Heat Matching with Very Low Carbon Heat Generators

SIPH, advanced nuclear reactors, and geothermal energy can be scaled to provide heat to most of the chemical industrial manufacturing plants in the United States. Examples of SIPH demonstration and operating commercial facilities can be adapted to industrial-process heating needs from small to large scales. The choice for a SIPH technology will be based on the area for deployment and the heat-transfer media that is used.

Nuclear heat energy will likely favor larger commercial operations simply to take advantage of economies of scale. Nuclear operations will require round-the-clock operators and security. Hence, for purposes of this study, it is assumed that the minimum energy service for a nuclear plant is 150 MW_t.

Geothermal energy systems have a high availability factor with inherent storage capability. This attribute makes geothermal energy amenable for several heating applications. However, geothermal energy would be difficult to economically transport from generation sites to an industry user.

4.1.1 SIPH System Examples

Currently, there are over 1,800 MW of installed concentrating solar power (CSP) in the United States (SEIA 2016). Installed capacity of parabolic trough collector SIPH is 4.028 MW_t (AEE INTEC 2016). A recent overview of CSP and SIPH around the world shows many systems are relatively small (ranging from 100 kW–100 MW_t), generating heat in the range of 150–300°C (Rawlins and Ashcroft 2013). These examples demonstrate the opportunity to apply SIPH to a wide range of industries, including the examples highlighted in this report. The list of CSP system demonstrations in the United States also could be readily applied to industrial heating loads—replacing or complementing fossil-fuel heat sources to reduce net emissions and the effect of price volatility that accompany fossil sources. Net capacity corresponds to the difference between gross generation and usage within the plant. Note that solar fields capture more energy first as heat than is transformed into electricity.

Table 9. CSP Projects for Electricity Generation in the United States (NREL 2016)

Project Name	Location	Owner	Turbine Capacity (MW)	Status
Maricopa Solar Project	Peoria, Arizona	Tessera Solar	Net: 1.5; Gross: 1.5	Non-Operational
Saguaro Power Plant	Red Rock, Arizona	Arizona Public Service	Net: 1.0; Gross: 1.16	Operational
Solana Generating Station (Solana)	Phoenix, Arizona	Abengoa Solar Liberty Interactive Corporation	Net: 250.0; Gross: 280.0	Operational
Genesis Solar Energy Project	Blythe, California	Genesis Solar, LLC	Net: 250.0; Gross: 250.0	Operational
Ivanpah Solar Electric Generating System (ISEGS)	Primm, California	NRG Energy; BrightSource Energy; Google	Net: 377.0; Gross: 392.0	Operational
Kimberlina Solar Thermal Power Plant (Kimberlina)	Bakersfield, California	Ausra	Net: 5.0; Gross: 5.0	Operational
Mojave Solar Project	Harper Dry Lake, California	Mojave Solar, LLC	Net: 250.0; Gross: 280.0	Operational
Sierra SunTower (Sierra)	Lancaster, California	eSolar	Net: 5.0; Gross: 5.0	Operational
Solar Electric Generating Station I (SEGS I)	Daggett, California (Mojave Desert)	Cogentrix	Net: 13.8; Gross: 13.8	Operational
Solar Electric Generating Station II (SEGS II)	Daggett, California (Mojave Desert)	Cogentrix	Net: 30.0; Gross: 33.0	Operational
Solar Electric Generating Station III	Kramer Junction,	NextEra (50%)	Net: 30.0; Gross: 33.0	Operational

Project Name	Location	Owner	Turbine Capacity (MW)	Status
(SEGS III)	California (Mojave Desert)			
Solar Electric Generating Station IV (SEGS IV)	Kramer Junction, California (Mojave Desert)	NextEra (38%)	Net: 30.0; Gross: 33.0	Operational
Solar Electric Generating Station V (SEGS V)	Kramer Junction, California (Mojave Desert)	NextEra (46%)	Net: 30.0; Gross: 33.0	Operational
Solar Electric Generating Station VI (SEGS VI)	Kramer Junction, California (Mojave Desert)	NextEra (41%)	Net: 30.0; Gross: 35.0	Operational
Solar Electric Generating Station VII (SEGS VII)	Kramer Junction, California (Mojave Desert)	NextEra (50%)	Net: 30.0 Gross: 35.0	Operational
Solar Electric Generating Station VIII (SEGS VIII)	Harper Dry Lake, California (Mojave Desert)	NextEra (50%)	Net: 80.0; Gross: 89.0	Operational
Solar Electric Generating Station IX (SEGS IX)	Harper Dry Lake, California (Mojave Desert)	NextEra (50%)	Net: 80.0; Gross: 89.0	Operational
Colorado Integrated Solar Project (Cameo)	Palisade, Colorado	Xcel Energy	Net: 2.0; Gross: 2.0	Non-Operational
Martin Next Generation Solar Energy Center (MNGSEC)	Indiantown, Florida	Florida Power & Light Co.	Net: 75.0; Gross: 75.0	Operational
Holaniku at Keahole Point	Keahole Point, Hawaii	Keahole Solar Power, LLC	Net: 2.0; Gross: 2.0	Operational
Crescent Dunes Solar Energy Project (Tonopah)	Tonopah, Nevada	SolarReserve's Tonopah Solar Energy, LLC	Net: 110.0; Gross: 110.0	Operational
Nevada Solar One (NSO)	Boulder City, Nevada	Acciona Energía	Net: 72.0; Gross: 75.0	Operational
Stillwater GeoSolar	Fallon, Nevada	Enel Green Power	Net: 2.0; Gross: 2.0	Operational

Project Name	Location	Owner	Turbine Capacity (MW)	Status
Hybrid Plant				
Tooele Army Depot	Tooele, Utah	Tooele Army Depot	Net: 1.5; Gross: 1.5	Operational

4.1.2 Small Modular Reactors

Commercial nuclear reactors to date have been used primarily for power production, but interest has increased in applying SMR and other advanced reactor technologies for process heat. Some possible configurations for transferring heat from a nuclear reactor(s) to the industrial user facility were previously studied under the NGNP program. An overview of this work and present research and development needs is summarized in a program plan for N-R HES (Bragg-Sitton et al. 2016).

The concept of an SMR originated in the 1970s for developing merchant ship propulsion and industrial process heat applications. Current commercial development of SMRs hopes to have operating reactors within 10 to 15 years. SMRs have the following potential advantages over conventional nuclear reactors (Bolden et al. 2014; Carelli 2015):

- Safety: SMRs have inherent passive safety features, higher safety margin from natural disasters and man-made impacts, and better seismic isolation.
- Cost: The modularity, reduced finance costs, and faster revenue potential capabilities expect to reduce the capital, manufacturing, and operating costs of SMRs. Other factors such as shared infrastructure, production and fabrication cost, construction schedule, and cost of debt favor lower costs with respect to SMRs.
- Enhanced availability: SMRs are likely to have enhanced availability in that multiple units on a site would allow fewer units to be refueled at one time while the other units continue to operate.
- Enhanced utility: Small units allow for more diverse operations such as distributed power or power generation in remote or isolated areas.
- Proliferation resistance and safety: Many of the SMR designs place the reactor underground, lessening security risks.

Table 10 lists many of the SMR concepts that are being developed in the United States and abroad. SMR development spans all types of reactors; for example, light-water reactors (LWRs), high-temperature gas reactors (HTGRs), liquid-metal reactors, and molten-salt reactors. The thermal capacities of these examples range from 30 to 1,000 MW_t. The temperature of the potential process heat varies from 300°C for LWRs up to 850°C for HTGRs.

Table 10. Summary of International SMR Development

Developer	Reactor Size (MW_t)	Primary Coolant	Reactor Outlet Temperature (ºC)
National Atomic Energy Commission: Central Argentina de Elementos Modulares (CAREM)	100	Light Water	326
China National Nuclear Cooperation: ACP-100	310	Light Water	303
China National Nuclear Cooperation: CNP-300	1,000	Light Water	302
Flexblue (France)	600	Light Water	310
Korea Atomic Energy Research Institute: System Integrated Modular Advanced Reactor (SMART)	300	Light Water	323
Russian Federation: ABV-6M	38	Light Water	330
Russian Federation: KLT-40S	150	Light Water	316
Russian Federation: RITM-200	175	Light Water	295
Russian Federation: VBER-300	900	Light Water	328
Generation mPower (US): mPower	530	Light Water	320
NuScale (US)	160	Light Water	300
HOLTEC: SMR-160	525	Light Water	316
Westinghouse Electric Company: W-SMR	800	Light Water	310
BhaBha Atomic Research Center: AHWR-300-LEU	920	Light Water	288
Nuclear Power Corporation of India Ltd.: PHWR-220	755	Heavy Water	293
Institute of Nuclear and New Energy Technology: HTR-PM (India)	250	Helium	750
Pebble Bed Modular Reactor: PBMR-CG (South Africa)	250	Helium	750
General Atomics: GT-MHR (US)	350	Helium	750
General Atomics: EM^2 (US)	500	Helium	850
Toshiba/Westinghouse: 4S (Japan)	30	Sodium	510
Russian Federation: SVBR-100	280	Lead-Bismuth	500
General Electric: Power Reactor Inherently Safe Module (PRISM) (US)	500	Sodium	500

Source: Ingersoll 2015

The SMART reactor from Korea will be used for power production and water desalination using a multi-effect distillation plant. The plant will use process heat to operate the distillation process to provide potable water. The AHWR-300 plant under development in India is also planned to provide the energy necessary to produce demineralized make-up water for AHWR using a low-temperature multi-effect desalination plant of 500 m^3 capacity per day (BARC 2016). The NGNP program considered numerous process-heat applications in which the HTGR can provide heat to produce products such as ammonia, methanol, liquid fuels, olefins, and hydrogen.

Heat from SMRs can be extracted from three primary locations: the reactor outlet, the turbines within the power-conversion unit, and heat rejected at condensers or ambient coolers. The location of heat extraction depends on industry-specific needs and whether the plant will provide CHP or electricity to the grid in a hybrid fashion. In either case, heat-transfer loops parallel to the power-conversion unit can transfer thermal energy to the industrial user.

Some industrial plant applications, such as steam-methane reforming and methanol production, require high-temperature heat of ~800°C. This requires heat-transfer systems that are designed to handle hot gases. It is assumed such applications will occur in close proximity to the plant. Figure 19 shows a simple block flow diagram indicating heat delivery to the primary reformer in a natural gas reforming plant. In the example, the primary coolant for the fluoride-salt cooled high-temperature reactor (FHR) is used to heat helium. The hot helium replaces the hot gas produced by natural gas combustion, which in some reforming plants consumes as much as 30% of the natural gas input to the plant. The helium loop also provides separation of the primary reactor coolant from the chemical plant.

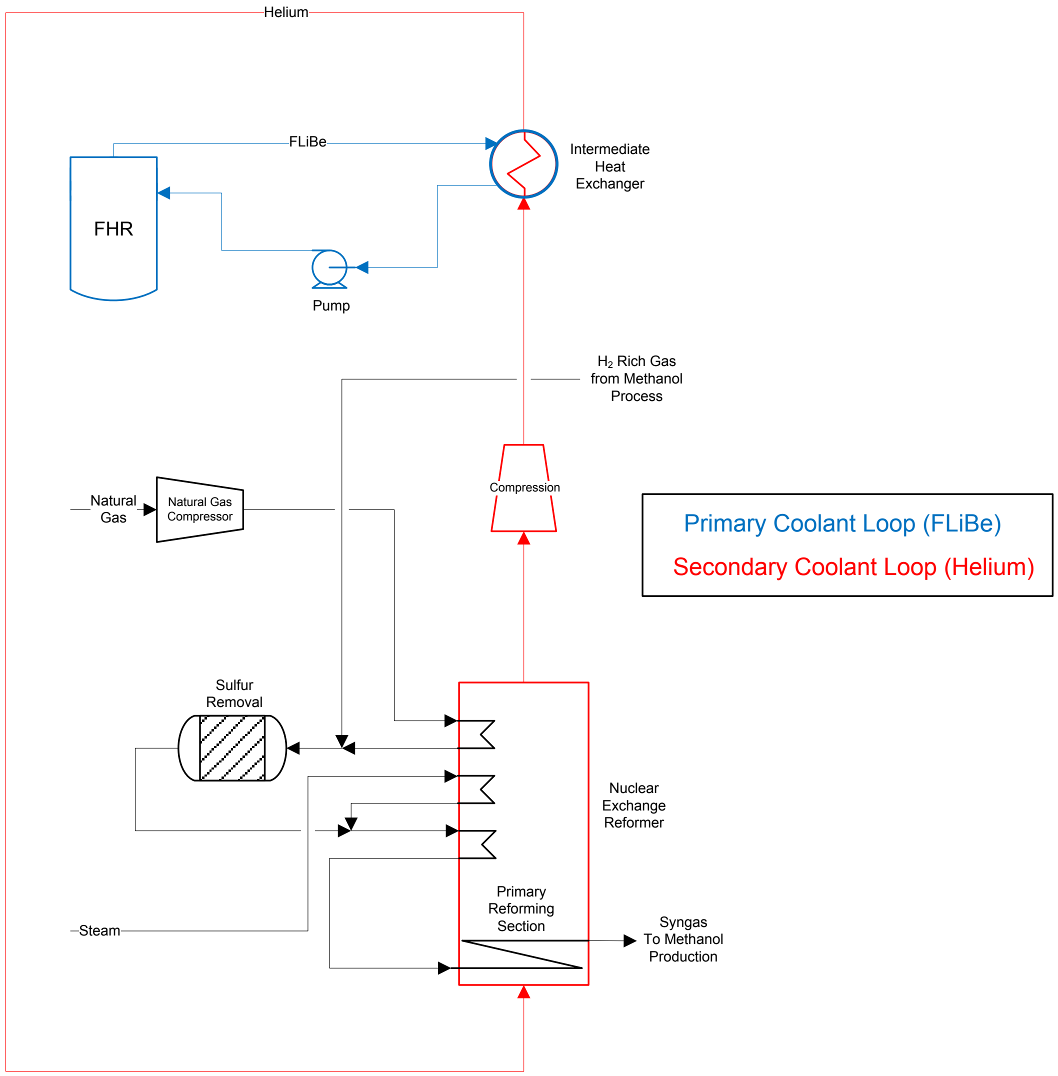


Figure 19. Integrated FHR and steam-methane reforming reactor

Source: Wood and McKellar (2013a)

Many process-heat applications require temperatures <300°C; for example, minerals drying and multi-effect evaporation. This temperature level is well suited for all SMRs. In the case of high-temperature reactors, the process heat extracted from turbines within the power-conversion unit may be used to provide such quality of heat. Extracting steam from turbines is a common practice for industrial processes.

Heat rejected by the power-conversion unit, either within a condenser or an ambient cooler, may be used for applications such as district heating. Although the amount of heat is large (up to two-thirds of the reactor heat), the availability of useful heat is limited due to its low temperature, <100°C.

Hydrogen production via high-temperature steam electrolysis has been modeled for a variety of reactor types. High-temperature steam electrolysis requires 800°C steam to pass through the solid-oxide electrolysis cells to produce oxygen and hydrogen. The high-temperature steam reduces the work into the cells (electricity) and thereby makes the process more efficient than low-temperature electrolysis. A sweep gas such as air or steam is used to remove the oxygen generated in the cells. Through the use of low-temperature and high-temperature recuperation, the reactor heat, ranging from temperatures of 300°C to 850°C, may be used to heat the process and sweep streams. The reactor heat is applied between the low-temperature and high-temperature heat recuperation. The heat from the reactor is used primarily to heat the process and sweep streams from a liquid state to a vapor state. Through the use of recuperation, only a small amount of topping heat is required to meet the conditions of the hydrogen cells. This heat can be supplied as electric heat without significantly affecting the efficiency of the hydrogen production (Wood and McKellar 2013b; McKellar 2010). Analyses indicate that the reactor outlet temperature primarily affected the power-production efficiency and, therefore, the hydrogen-production efficiency.

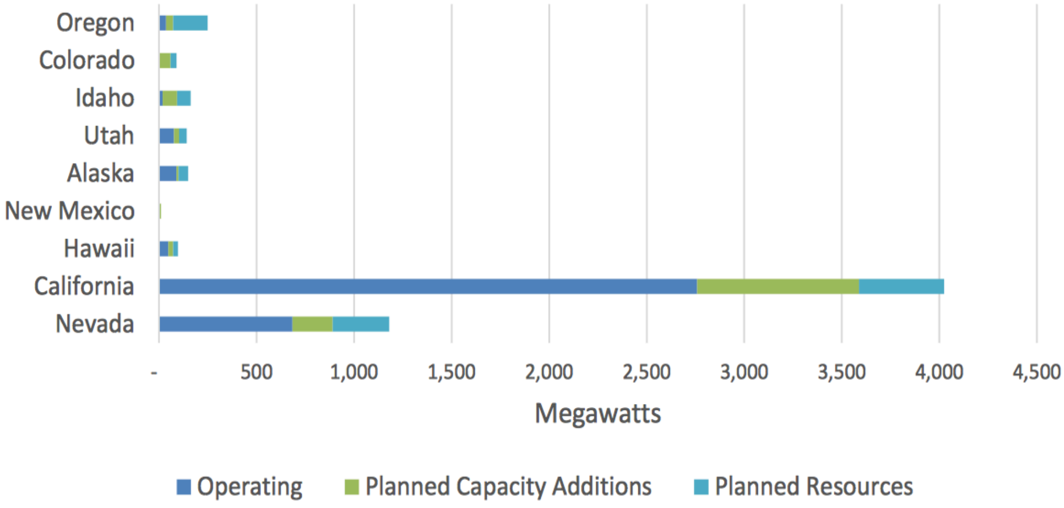
Preliminary plant-design simulation studies illustrate the potential use of nuclear heat in methanol production (Wood and McKellar 2013a). The reactor heat needed for such substitution will need to be derived from higher-temperature reactors such as FHRs and HTGRs.

4.1.3 Geothermal

Traditionally, geothermal energy has been used as a baseload power source among renewables. It is also being looked at as a potential flexible power source, balancing intermittent wind and solar power production and reducing variability in energy price and as a heat source for non-electrical applications (DOE 2016b). Currently, geothermal energy constitutes less than 1% of the total U.S. electricity generation, and it is mainly located in the Western states in the mountainous regions associated with active tectonic plate movement and near volcanic hot spots. Since 2005, the United States has built over 38 geothermal power projects, adding nearly 700 MWe to the U.S. electricity capacity. Table 11 details the installed geothermal capacity, in MWe, by state as of February 2013. Figure 20 shows the current developing planned capacity additions and nameplate capacity by state.

Table 11. Installed U.S. Geothermal Capacity as of 2013[2]

State	Capacity (MWe)	Share of U.S. Total (%)
California	2,732.20	80.70
Nevada	517.50	15.30
Utah	48.10	1.40
Hawaii	38.00	1.10
Oregon	33.30	1.00
Idaho	15.80	0.50
New Mexico	4.00	0.10
Alaska	0.70	<0.10
Wyoming	0.30	<0.10
Total	3,389.9	100



Note: Planned Capacity Additions (PCA) is the power plants estimated installed capacity.

Figure 20. Planned capacity additions and nameplate capacity by state

Source: Geothermal Energy Association (2016)

Geothermal energy systems have a high availability factor with inherent storage capability. This attribute makes geothermal energy amenable for several heating applications. For example, agricultural and aquacultural applications require temperatures from 25–90°C; space heating requires temperatures in the range of 50–100°C; cooling and industrial processing require temperatures over 100°C (Lund 1996); drying and dehydration are other possible uses of geothermal energy, with application in manufacturing chemical industry such as the pulp/paper and petroleum industries, which could utilize a heating media with a temperature in the range of 150–200°C (Tester et al. 2005). For example, the largest direct geothermal energy resource user in the world is Norske Skog Tasman pulp and paper mill in Kawerau, New Zealand, which uses geothermal fluids to generate steam (0.7 MPa, 171°C) for paper drying, a heat source for evaporators, and for electricity generation (White 2006).

Geothermal resource can be categorized in dimensions of temperature, depth, and permeability/porosity (Tester et al. 2005), as well as fluid. Conventional production of electricity is generally limited to fluid temperatures above 150°C, but considerably lower temperatures down to about 70°C can also be used with the application of binary fluids (Fridleifsson 1996). Geothermal production wells are commonly up to 2 km deep. The temperature rise with increasing depth in the crust averages about 25–30°C/km. This is referred to as the geothermal gradient (Tester et al. 2005).

An assessment carried out by United States Geological Survey (USGS) estimated that the electric power generation potential from identified geothermal systems is about 9 GW_e distributed over 13 states (Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming). Resources were categorized as moderate-temperature (90–150°C) and high-temperature (greater than 150°C) geothermal systems located on both private and accessible public lands (Williams et al. 2008). Low-temperature (below 150°C) and co-produced resources represent a small but growing sector of geothermal development (DOE 2016b).

Figure 21 shows the locations of existing and potential hydrothermal sites and locations favorable to deep enhanced geothermal systems (EGS), these systems are created where hot rock is present but has insufficient or little natural permeability or fluid saturation (DOE 2016b; Augustine 2011). A summary of the results of the DOE geothermal resource potential capacity estimate for the United States is shown in Table 12. However, geophysical tools still lack the ability to accurately identify and remotely predict temperatures at target depths; thus, a geothermal resource is not confirmed until a well is drilled into a target reservoir, which could be a substantial upfront investment cost.

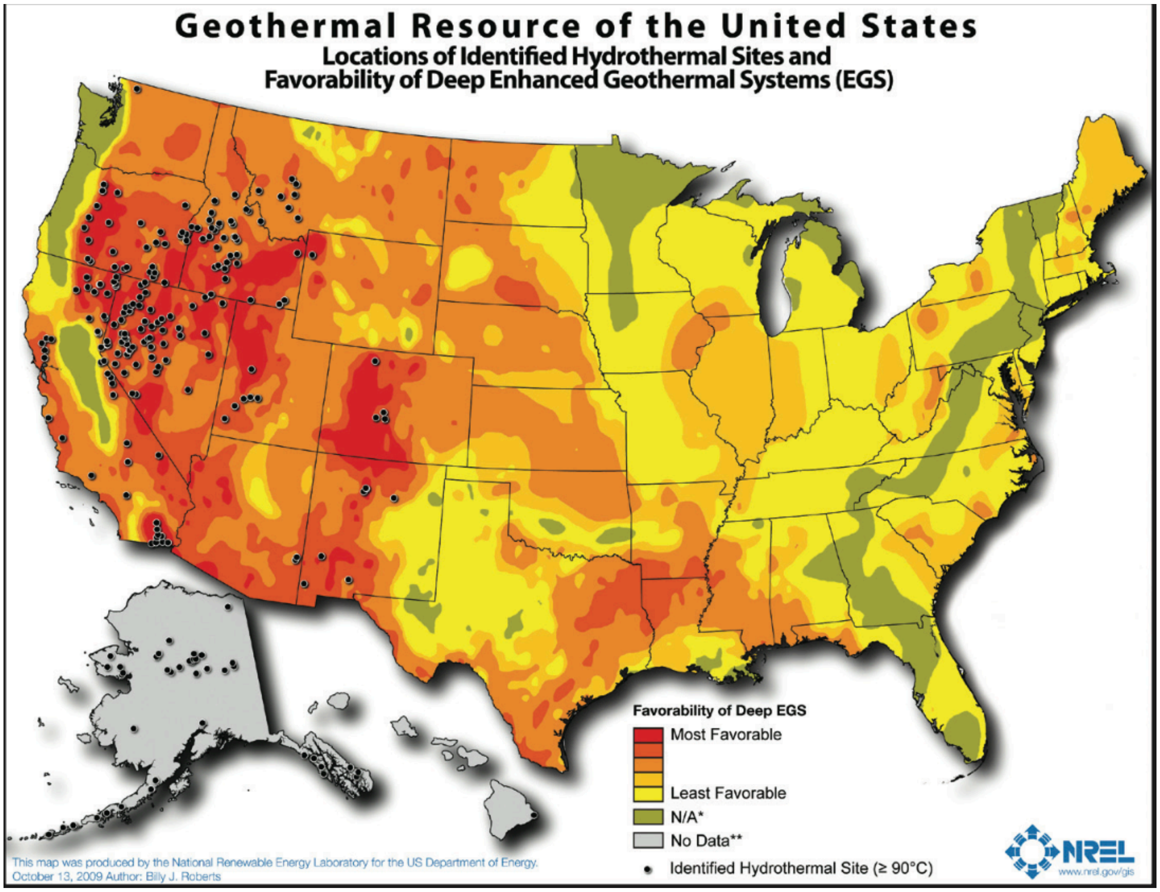


Figure 21. Geothermal resources of the United States

Source: DOE (2016b)

Table 12. Summary of U.S. Geothermal Resource Potential

Resource		Resource Potential	
		Capacity (GW_e)	Source(s) and Description
Hydrothermal	Identified Hydrothermal Sites	6.39	USGS 2008 Geothermal Resource Assessment[a] • Identified hydrothermal sites • Sites ≥110°C included • Currently installed capacity excluded
	Undiscovered Hydrothermal	30.03	USGS 2008 Geothermal Resource Assessment[a]
Enhanced Geothermal Systems (EGS)	Near-Hydrothermal Field EGS	7.03	Based on data from USGS 2008 Geothermal Resource Assessment[a] and methodology developed at NREL • Regions near identified hydrothermal sites • Sites ≥110°C included • Difference between mean and 95th percentile hydrothermal resource estimate
	Deep EGS	15,908	NREL 2006 Update,[b] MIT Report,[c] SMU Data[d] • Based on volume method of thermal energy in rock 3–10 km depth and ≥150°C • Does not consider economic or technical feasibility

Source: Augustine (2011)
[a] Williams et al. (2008)
[b] Petty and Porro (2007)
[c] Tester et al. (2006)
[d] Richards (2009)

U.S. distribution of potential geothermal energy use versus heat-application temperature has also been projected by Tester (2005), who indicates the total amount of energy use below 250°C is equal to 31.7 EJ (30 quads, or 8,800 TWh).

Unlike wind and solar resources, which are more dependent on weather fluctuations and climate changes, geothermal resources tend to have a much higher capacity factor, while the common medium for geothermal energy source is water, which in some parts of the country is sparse and is a much-valued commodity. A different heat-transport medium, such as CO_2, is being studied that has been indicated to potentially be superior to water in achieving larger heat-extraction rates when the same injection pressure is applied; however, the challenge lies in the need for the reservoir to be completely dry before CO_2 is injected to avoid formation of carbonic acid (DOE 2016b). One of the inherent challenges with geothermal energy is that it cannot be moved or transported to generation sites or near an industry compared to the alternative sources; it must be located in regions with advantageous subsurface conditions, which do not always coincide with the locations of the industries.

To advance the geothermal technology such that cost and risks associated could be reduced, ways to derive more value from the resource need to be identified and developed. Key areas identified in the DOE Quadrennial Technology Review that have the potential to impact geothermal deployment are: resource characterization and exploration technologies, control of subsurface fracturing and flow, improved subsurface access technologies, and additional value added to operations through mineral recovery and hybrid systems (DOE 2016b). Frontier Observatory for Research in Geothermal Energy (FORGE), a DOE initiative, is designed to address some of these areas and potentially become a dedicated test site. Going forward, geothermal plants with high availability and reliability could also ramp up and ramp down electricity generation output, providing flexibility and ancillary services; provide heat/thermal energy to drive lower-temperature applications; and provide a source of elements for industries, thus expanding its market value beyond just power production and making them more commercially viable.

4.1.4 Heat Use Comparison

This section projects the potential opportunity to use SMR, SIPH, and geothermal heat in the 14 target industries. The pulp and paper and petrochemical industries have suitable temperature ranges for SMRs and SIPH but were excluded from this total due to their reliance on process byproducts as combustion fuels. The use of hydrogen as a combustion fuel was also excluded from the analysis.

Currently SMR technology is being developed to provide thermal heat ranging from 300–850°C. Assuming that the smallest practical SMR module is 150 MW$_t$ and based on process heat inputs listed in

Table 14, 463 SMR units could provide 1,480 PJ/yr heat demand to the applicable target industries. The potential temperature limit for SIPH has not been established, but we assumed that the practical upper limit is 1,000°C. Assuming the scale of SIPH is limited to an upper size of 250 MW_t and based on the average daily heat use identified in Table 8, SIPH could supply as much as 1,480 PJ/yr to the applicable target industries. Geothermal heat conditions are set by the environmental conditions but currently operate at temperatures up to 150°C for thermal applications. At this temperature limit geothermal energy could support 70 PJ/yr of industrial heat based on the average daily heat use identified in Table 8 for wet corn milling.

Table 13. Summary of Heat Generators and Potential Industrial Users

Heat Generators	Assumed Avg. Heat Output (MW_t)	Available Expected Temperature (°C)	Industries
SIPH (CSP) Units	1–100	Not determined in this study, assumed limit is 1,000	Petroleum refineries, chemical industries, ethyl alcohol, plastic materials and resins, alkali and chlorine, potash, and soda and borate mining
Geothermal Units	1–50	150	Wet corn milling
SMR[a]	100–600	300–850	Petroleum refineries, chemical industries, ethyl alcohol, plastic materials and resins, alkali and chlorine, potash, and soda and borate mining

[a] Advanced materials development will support high-temperature gas-cooled SMR temperatures up to 950°C.

Based on the assumed average heat capacity for SMRs and temperature requirement within different industries, the number of required units to meet total industrial thermal (heat) needs is shown in

Table 14. The number of SMRs for petroleum and the iron and steel mills include those dedicated to hydrogen production using high-temperature steam electrolysis; note that SMRs are assumed to not provide heat for iron and steel mills. For a LWR SMR, 439 MW_t/(kg/s of hydrogen produced) is used to estimate the SMR number. For the iron and steel mills, 83 kg of hydrogen per ton of steel produced can be used to replace the coke used within the refineries.

Table 14. Number of SMR Units (150 MW_t scale) Required to Meet Selected Industrial Needs

Industry Subsector	Target Industry	Heat Input (MW_t)	Number of Plants	Number of SMRs	Hydrogen (tonnes/day)
Petroleum and Coal Products	Petroleum Refineries	13,456	141	399	9,130
Primary Metal Manufacturing	Iron and Steel Mills	3,225	115	226[a]	6,690
Paper Manufacturing	Paper and Paper-Board Mills	20,799	189	NA	
	Pulp Mills	1,496	30	NA	
Chemical Manufacturing	All other Basic Chemical Manufacturing (Methanol)	12,714	85	85	
	Ethyl Alcohol Manufacturing	3,445	168	23	
	Plastics Material and Resin Manufacturing	8,780	72	60	31.2
	Petrochemical Manufacturing (Ethylene)	962	35	NA	
	Alkalies and Chlorine Manufacturing	545	11	4	
	Nitrogenous Fertilizer Manufacturing (Ammonia)	2,448	30	16	
Food Manufacturing	Wet Corn Milling	2,239	24	15	
Nonmetallic Mineral Product Manufacturing	Lime	1,728	49	NA	
	Cement	12,760	117	NA	
Mining (Except Oil and Gas)	Potash, Soda, and Borate Mining (Soda Ash)	3,318	11	22	

Note: NA refers to not applicable, as the required temperature of the respective industry is higher than the available temperature range between 300 and 850°C from SMR or the industry relies on its own process byproducts as combustion fuels. For number of units, an SMR of 150 $MW_{t.}$ has been used. The reason for not including number of required units for geothermal and SIPH plants is because of large variability in available heat capacity.

[a] Feedstock hydrogen only.

4.2 Heat Transport

This section focuses on heat-transport systems that can potentially link nuclear and concentrating solar systems to industrial processes.

4.2.1 Heat-Transfer Fluids

Table 15 lists some of the properties and characteristics of common heat-transfer working fluids that are used by the petrochemical and chemical industries. The selected industrial application and its corresponding temperature requirement dictate which fluid may be used to transfer thermal energy. The key fluid decision discriminators include: heat-transfer capacity, rheological properties, availability of the fluid, material compatibility, and cost. The selection of the best heat-transfer fluid considers:

- Temperature of process-unit operation
- Heat-exchange method: direct versus indirect contact with the process reactor, heat-exchanger design (e.g., gas or liquid circulation compatibility)
- Economics: cost and availability of the heat-transfer fluid, pumping costs, thermal stability, and retrofit or new process reactor design cost-benefit feasibility
- Heat-transfer properties: heat capacity and thermal conductivity, freezing/melting point, and heat-transfer coefficient
- Rheological properties: density, kinematic viscosity, and compressibility
- Technical compatibility: corrosivity of heat-delivery system, reactivity with process reactants, and volatility
- Safety: toxicity and reactivity with air or water.

The previous section indicates that industry heating is largely based on pressurized hot water and superheated steam-circulation systems. However, two-phase, thermally stable, synthetic organic heat-transfer fluids (e.g., Dowtherm) are also popular because they may avoid corrosion issues associated with steam systems. Some synthetic fluids may have better heat-transfer coefficients, considering fluid viscosity, specific heat, density, and thermal conductivity. Non-aqueous heat-transfer fluids are also preferred for winter conditions and they can avoid pipe corrosion. Inorganic salts and liquid metals also provide a practical heat-transfer media. They can be heated electrically or with a fired heater.

For process temperatures below 600–650ºC, steam has many advantages:

- Steam is an inexpensive and common heat-transport fluid and has a long history as a heat-transfer fluid.
- After the heat is transferred to the process, the steam condenses to water, which greatly reduces power required to recirculate the heat-transfer fluid. Pumping water requires less power than recirculating a gas.
- Steam has one of the highest heat capacities at higher pressures (comparable to molten salts), as shown in Table 15.

- Steam has a low freezing point compared to molten salts and metals.

Gases that are heated by an external heat-generation source or an electrical heater can readily replace steam and hot combustion gases that are passed through reactor-vessel coils or jackets. Helium has a relatively high heat capacity and thermal conductivity compared to other gases. It is generally not prone to metals oxidation and interaction, although studies have shown that helium strips carbon from high-temperature alloys unless trace amounts of CO are added to the gas. The downside to helium may be its cost and operating pressure requirements. Helium is only produced by nuclear processes. Naturally occurring helium has accumulated over previous geological periods and is now mainly found in natural gas reservoirs. Therefore, it must be separated and supplied for heat applications in amounts that could exceed future production capacity. Unlike steam, which can be generated from pressurized water and can be circulated with a pump, helium must be compressed to force circulation. Additionally, helium is pressurized and circulated at high velocities to increase the heat-transfer rate when used for process-heating applications.

Liquid metals and molten salts have very high heat capacities and can efficiently transport heat over long distances because liquid pumps require significantly less energy than gas compressors. Table 15 lists only a few of the metals and salts that have been investigated for nuclear and SIPH systems. The main advantages of liquid metals are the very high heat capacities, comparatively low viscosities, and low corrosion performance characteristics. Sodium, in particular, is practically noncorrosive to stainless steel. Sodium exhibits a relatively high vapor pressure at temperatures approaching its boiling temperature of 883°C. Liquid lead and lead-bismuth have much high boiling temperatures (1,737°C and ~1,670°C, respectively); however, they exhibit aggressive corrosion by direct dissolution by surface reactions, and therefore, they can only be operated at fluid velocities less than 3 m/s. The chief concern of liquid metals, however, is reaction with air and water and is a known concern.

Molten salts are gaining popularity for both nuclear reactors and CSP systems. A recent review of the characteristics of molten salts lists the benefits of salts relative to liquid metals and gases (Yoon et al. 2014; McKellar et al. 2011). The most common salts that are being proposed for heat transfer in these systems are alkali-based nitrates and carbonated, zirconia-based fluorides and chlorides. Only a few of these salts are listed in Table 15 for illustrative purposes.

Molten salts also exhibit the highest volumetric-specific heat capacities. Some can operate at very high temperatures without decomposing, although nitrate and carbonate salts are an exception. Solar salt ($NaNO_3$ KNO_3), for example, becomes thermally unstable around 600°C. In comparison, mixtures of alkalis-fluorides-zirconium carbonates are thermally stable at temperatures exceeding 900°C. The downside of molten salts includes the propensity for corrosion, particularly with the fluoride and chloride salts. Consequently, corrosion will continue as an important topic for emerging nuclear reactors and CSP technology.

Table 15. Properties and Characteristics of Common Heat-Transfer Working Fluids

Name	Specific Heat Capacity (kJ/kg-K)	Thermal Conductivity (W/m-K)	Dynamic Viscosity (kg/m-s)	Density (kg/m^3)	Heat Capacity Density (kJ/m^3-K)	Kinematic Viscosity (m^2/s)	Temp. Melting/ Boiling (ºC)
Two-Phase Fluids							
Saturated Steam							
@ 500 K (122 atm)	3.27	4.23E-02	1.66E-05	13.05	42.69	1.27E-06	0/227
@ 625 K (167 atm)	18.3	1.21E-01	2.70E-05	117.6	2153	2.30E-07	0/352
Saturated Dowtherm Vapor							
@ 530 K (1 atm)	1.835	2.40E-02	1.00E-05	4.003	7.346	2.50E-06	12.0/257.1
@ 668K (9.86 atm)	2.286	3.58E-02	1.34E-02	39.25	89.73	3.41E-04	12.0/395
Gases							
Air							
@ 500 K & 1 atm	1.03	4.07E-02	2.70E-05	0.6964	0.7173	3.88E-05	NA
@ 1,000 K & 1 atm	1.141	6.67E-02	4.24E-05	0.3482	0.3973	1.22E-04	NA
@ 500 K & 98.7 atm	1.03	4.07E-02	2.70E-05	67.02	69.03	4.03E-07	NA
@ 1,000 K & 98.7 atm	1.141	6.67E-02	4.24E-05	33.74	38.50	1.26E-06	NA
Carbon Dioxide							
@ 500 K & 1 atm	1.02	3.25E-02	2.31E-05	1.059	1.081	2.18E-05	NA
@1,000 K & 1 atm	1.22	6.79E-02	4.55E-05	0.5362	0.6564	8.48E-05	NA
@ 500 K & 98.7 atm	1.17	3.86E-02	2.86E-05	113.0	132.1	2.53E-07	NA
@1,000 K & 98.7 atm	1.25	7.04E-02	4.64E-05	51.71	64.61	8.97E-07	NA
Helium							
@ 500 K & 1 atm	5.193	2.20E-01	2.83E-05	0.09754	0.5065	2.90E-04	NA
@ 1,000 K & 1 atm	5.193	3.54E-01	4.46E-05	0.04879	0.2534	9.14E-04	NA
@ 500 K & 98.7 atm	5.193	2.20E-01	2.83E-05	9.381	48.715	3.02E-06	NA
@ 1,000 K & 98.7 atm	5.193	3.54E-01	9.14E-04	4.762	24.73	1.92E-04	NA

Name	Specific Heat Capacity (kJ/kg-K)	Thermal Conductivity (W/m-K)	Dynamic Viscosity (kg/m-s)	Density (kg/m^3)	Heat Capacity Density (kJ/m^3-K)	Kinematic Viscosity (m^2/s)	Temp. Melting/ Boiling (ºC)
Liquids and Salts							
Sodium							
@ 366 K	1.39	8.62E+01	6.98E-04	929.1	1291	7.52E-07	97.8/883
@ 977 K	1.26	5.97E+01	1.78E-04	778.5	980.9	2.29E-07	97.8/883
Lead-Bismuth							
@ 561K	0.147	10.7	1.76E-03	1.03E+04	1514	1.71E-07	125/1,670
@ 922 K	0.147	2.7	1.15E-03	9.84E+03	1446	1.17E-07	125/1,670
Hitec XL ($NaNO_3$ KNO_3 $Ca(NO_3)_2$)							
@ 575 K	1.45	0.52	6.37E-03	1870	2712	3.41E-06	120/500
LiF-NaF-KF							
@ 750 K	1.77433	0.78	9.75E-03	2111	3746	4.62E-06	450/1,570
@ 1,000 K	2.04018	0.92	2.19E-03	1955	3989	1.12E-06	450/1,570
KF-ZrF_4							
@ 750 K	1.051	0.32	1.10E-03	2751	2891	4.01E-07	390/1,450
@ 1,000 K	1.051	0.32	3.82E-04	2529	2658	1.51E-07	390/1,450
KCl-$MgCl_2$							
@ 750 K	1.15	0.0931	2.88E-03	2008.34	2310	1.43E-06	426/1,418
@ 1,000 K	1.15	0.1241	1.35E-03	1889.84	2173	7.16E-07	426/1,418

In summary, steam and hot gases are currently compatible with the chemical process industries. Liquid metals and molten salts likely are not compatible with cast iron, ductile iron, and stainless-steel heat exchangers and reactor vessels/piping. Consequently, it is likely that a secondary or tertiary heat exchanger with a non-reactive heat-transfer media will be required for liquid-metal- and salt-cooled reactors.

4.2.2 Heat-Transfer Distance

Several factors govern the distance of the heat source to process unit operations:

1. Safety considerations
2. Heat-source scale versus heat user demand (or the capacity-matching criterion)
3. Quality of heat required by the user (or temperature of the working fluid).

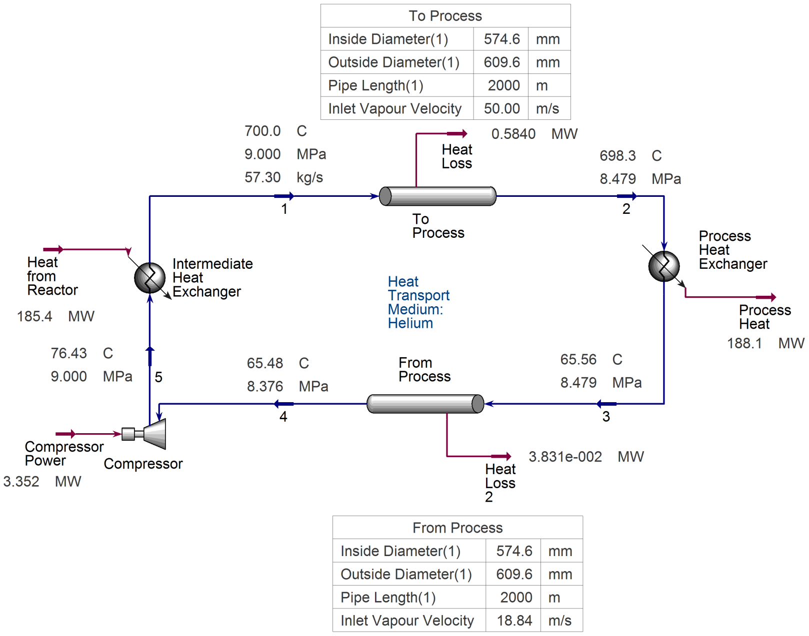
Given that safety is the highest priority, some important factors to consider for nuclear reactors include regulatory constraints and exclusion-zone considerations. A probabilistic risk assessment (PRA) is a guiding criterion. Compared to conventional LWR technology, modern SMR designs tend to have reduced risk by two or three orders of magnitude, due to passive safety inherent characteristics and can be shown using PRA methods (NRC 2016). When collocated with a chemical plant, the PRA may need to call out the hazards of the chemical plant. An ammonia plant, for example, may have a specific stand-off distance required to protect the nuclear reactor operations and vice versa.

Security of the nuclear plant and fuel storage operations is another issue to consider. Currently, a central storage location for commercial nuclear fuel does not exist. This issue is, however, being taken up by the DOE Office of Nuclear Energy with impetus from a recent LINE Commission on fuel handling and dispositioning in the United States (LINE 2016).

Technical considerations for heat-transfer distance, such as capacity matching and working fluid temperature, are straightforward but not necessarily easy. The considerations could benefit from more research and development. Previous work concluded that steam/water and molten salts perform better than gases for relatively long heat-transfer distances (up to 20 km), primarily because low-pressure gases such as helium require extremely high pumping power (McKellar 2011). The high pumping power makes long-distance hot-gas transport inefficient and economically nonviable for both low- and high-temperature applications (Yoon et al. 2014; McKellar et al. 2011).

An illustrative example here demonstrates the technical analysis that is part of a technical/economic assessment of any industrial plan retrofit or new plant. A thermal hydraulic model was developed to compare the energy costs and heat-delivery capacity of a heat-transfer circulation loop for a nuclear reactor that is located about two kilometers from a process plant. In this case, it is assumed that a hot gas, namely helium, will circulate through a heating jacket at the chemical plant. The question that arises is whether it is most cost effective to position a secondary heat exchanger (molten salt/helium) in close proximity to the nuclear reactor, or adjacent to the chemical process vessel that will be heated by helium gas circulation.

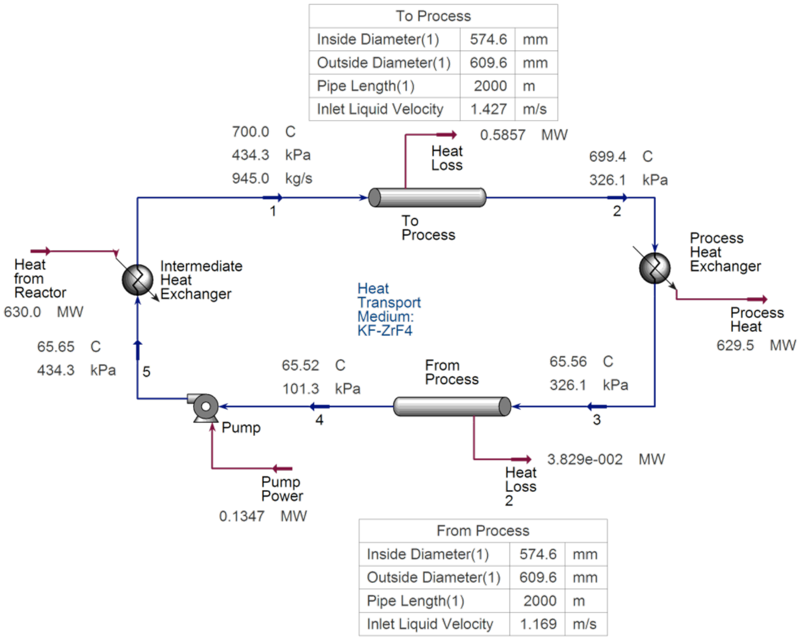
Figure 22 and Figure 23 compare the transport of molten $KFZrF_4$ to helium using a circulation loop of a comparable size. For this comparison, the pipe is considered to be buried, although this may not be practical when considering thermal-expansion design requirements. The molten salt, having the highest volumetric heat capacity and lowest pumping energy, is capable of transporting 54.4 TJ/day or 629 MW_t (at a coefficient of performance of 4,670 TJ/day-MWe) versus 16.3 TJ/day or 188 MW_t (at a coefficient of performance of 4.85 TJ/day-MWe) using helium in the same sized piping system. The coefficient of performance is the heat divided by the pumping or compression power used to transport the heat. In a practical engineering design, pipe material and corrosion, as well as pump versus compressor costs, are important considerations.



To Process		
Inside Diameter(1)	574.6	mm
Outside Diameter(1)	609.6	mm
Pipe Length(1)	2000	m
Inlet Vapour Velocity	50.00	m/s

From Process		
Inside Diameter(1)	574.6	mm
Outside Diameter(1)	609.6	mm
Pipe Length(1)	2000	m
Inlet Vapour Velocity	18.84	m/s

Figure 22. Operating conditions and performance of a 2-km helium circulation loop



To Process		
Inside Diameter(1)	574.6	mm
Outside Diameter(1)	609.6	mm
Pipe Length(1)	2000	m
Inlet Liquid Velocity	1.427	m/s

From Process		
Inside Diameter(1)	574.6	mm
Outside Diameter(1)	609.6	mm
Pipe Length(1)	2000	m
Inlet Liquid Velocity	1.169	m/s

Figure 23. Operating conditions and performance of a 2-km molten-salt circulation loop

4.2.3 Clustering Opportunities (Industrial Parks)

The preponderance of the scale and location of the industrial manufacturing market suggests that one heat source—either an SMR or SIPH—may be practical for a cluster of industries or an EP where a set of industries is serviced by a large central multi-energy (ME) heat source (e.g., Kurup and Turchi 2015). The Electrical Power Research Institute (EPRI) studied EP and ME concepts over a decade ago to understand how specific electrical, mechanical, and thermal energy currency—both individually and in combination—can be derived from a menu of distributed generation resources options (EPRI 2003). The basic example of a ME system is a CHP application with an integrated energy-management control scheme to optimally balance heat production with electricity demands.

The EPRI reports point out that "A key step in identifying the requirements for a ME-based system is to evaluate the energy needs of the loads to be served" (EPRI 2003). The larger diversity of loads present in an EP can possibly help to simplify the application of suitable generation systems by allowing improved load factors for both thermal and electrical loads.

An ME concept that is gaining some interest is N-R HES. A report on the economic potential of N-R HES concludes that the systems would be economically feasible if capacity payments are adequate and the systems mainly provide thermal energy to industry or an EP while also dispatching electricity to the grid to support power-generation resources adequacy (Ruth et al. 2016a).

4.3 Heat Recuperation

Modern chemical plants optimize heat integration to achieve the highest thermodynamic efficiency possible on a cost-benefit basis. Such principles make it possible to use a lower-grade heat source to preheat the reactants entering a process, followed by heat exchange with hot products leaving the reactor. Then the final heat-up to reacting conditions can be achieved and maintained by a topping-heat cycle. An example of this concept is high-temperature steam electrolysis.

High-temperature steam electrolysis achieves the optimal thermodynamic efficiency around 850°C. Intermediate-temperature/pressure steam entering the process can be generated by an LWR or SIPH that delivers saturated steam to the process. Figure 24 plots the enthalpy of states of steam that was first heated by low-temperature heat recuperation, followed by heating and vapor superheating accomplished with a secondary heat loop associated with an LWR or SIPH. High-temperature heat recuperation is restricted only by the minimum approach temperature of the heat exchanger, which is generally limited to 10–15°C to optimize heat-exchanger costs versus heat-transfer efficiency (Sabharwall 2011). The minimum approach temperature is the minimum temperature difference between the hot and cold side of a heat exchanger. The final heat-up is completed with a topping heater. In the illustration, electrical heating is used because it is cost effective for the relatively small amount of heating that is needed for this case.

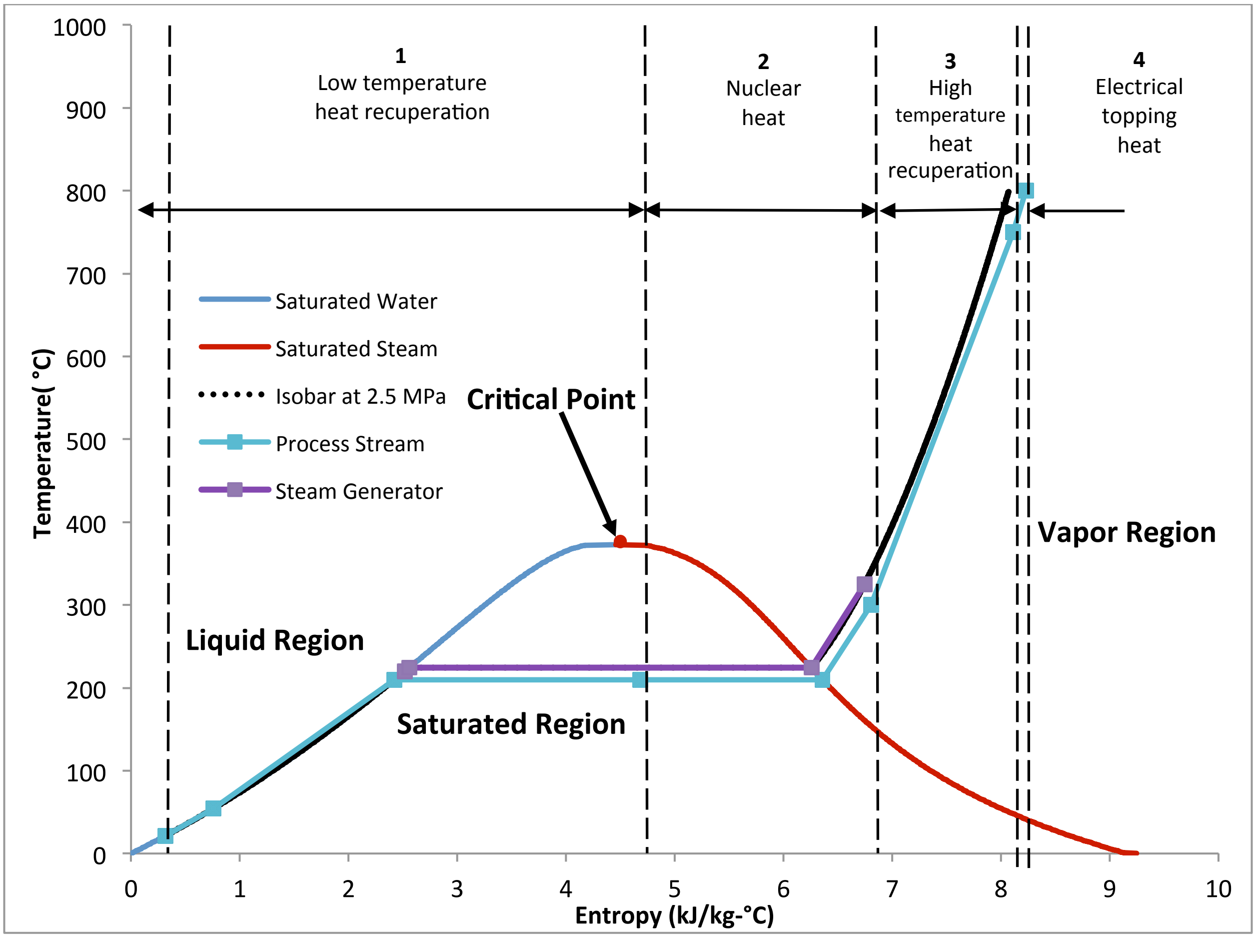


Figure 24. Steam heat-up for high-temperature steam electrolysis

Steam generation through heat recovery is commonly performed with a heat recovery steam generator, where tail gases are often burned to reduce pollutant emissions, while generating steam for CHP purposes. This concept is also an option for raising the temperature of 300°C steam provided by an SMR or SIPH, which then can be used in processes that require higher-quality steam. Oil refineries and chemical synthesis plants are examples where this concept may reduce fossil-fired heaters that currently operate on natural gas.

McKellar (2011) compared a variety of heat-transfer fluids for the transport of heat from an HTGR to generate steam for oil sand production sites. The study compared steam, carbon dioxide, helium, FLiNaK, and Dowtherm with the distance of 25 km between the well pads and the reactor. In this case, the heat-transport pipeline was constructed from 24-inch, Schedule 160 pipe, with a 6-inch casing of Aerogel insulation. The temperature of the steam was limited to 550ºC to prevent pipeline damage. The temperature of Dowtherm was limited to 405ºC (which is likely the high end of operation for this organic fluid). The quality of steam generated at the well head was 310ºC/10 MPa. In this case, FLiNaK and steam exhibited the best comparative technical performance within the analysis. Although FLiNaK performed well, the mass required to be used by the delivery and return lines is more than twice the other heat-transfer fluids. The main conclusion of the analysis was that steam was the best heat transfer fluid for this application because of low pumping costs, low cost and readily accessible fluid, and ability to transport heat duty on the order of liquids and salts.

4.4 Chemical Heat Pumps and Heat Transport

Chemical heat pumps can serve two technical purposes: first, to amplify the temperature of a thermal hydraulic fluid, and second, to transport energy that is converted into heat at the point of heat use. In the latter case, heat transport over longer distances is accomplished simply through the transport of chemically bound energy. In both cases, the heat source involves an endothermic reaction that absorbs heat to create a transportable product that releases its heat through a reversible reaction. The most attractive transport systems could be defined with the following conditions (Kugeler et al. 1975):

- The chemical reaction needs to be reversible.
- The reaction enthalpies should be as high as possible so that the transported product has a high energy density.
- The forward and backward reactions need to have favorable temperatures.
- The catalysts needed for the reactions should be readily available and low cost.
- Toxic or corrosive substances should be avoided.
- The reactants and products utilized should be readily available.

The advantage of chemical heat pumps is that no heat is lost along the pipeline because the fluid is not heated but transported at ambient temperatures. Reactions under consideration include the reforming of methane with steam or carbon dioxide, the dissociation of ammonia, and other chemical catalytic reversible reactions.

An example of a chemical heat pump is methane reforming and re-methanation. Methane reforming with steam is an overall endothermic reaction:

$$CH_4 + H_2O(l) \leftrightarrow CO + 3H_2,\ \Delta H_{298K} = 250\ \text{kJ/mol}\ (CH_4)$$

$$CO + H_2O(l) \leftrightarrow CO_2 + H_2,\ \Delta H_{298K} = -41.2\ \text{kJ/mol}\ (CO)$$

The methanation reaction is exothermic:

$$CO + 3H_2 \leftrightarrow CH_4 + H_2O(l),\ \Delta H_{298K} = -250\ \text{kJ/mol}\ (CH_4)$$

In this chemical loop, the source heat (nuclear reactor or SIPH) is used to produce synthetic gasoline, which is transported to the industrial process where the synthetic gasoline goes through a methanation process to release the heat. The methane returns to the heat source. A 950ºC HTGR can provide ultra-high-pressure steam qualities at the user site (Kugeler et al. 1975; Ma et al. 2009; Fedder and Hoehlein 1982).

Sorption processes may also be used to transport low-grade heat over long distances. For example, ammonia-water absorption cycles have been shown to provide both heat and cooling at user sites using waste heat at the source. The coefficient of performance (heating or cooling divided by power input) has been shown to be 0.43 to produce chilled water at 8ºC with an ambient temperature of 35.5ºC; a coefficient of performance of 0.45 can produce heat at 59.2ºC with an ambient temperature of 9ºC (Mazet et al. 2010; Lin et al. 2011). Lithium bromide-water systems could also function similarly; however, at least one study has shown that this system may cost more than the ammonia system (Ma et al. 2009).

4.5 Electrical Heating

Several forms of electrical heating are employed in the process industries. Electro-heating has several advantages, including clean operations (no emission and effluent problems), constant quality and availability, rapid application, and relative ease of temperature control. Common techniques for electrical heating include resistive heating, induction heating, dielectric heating, and infrared heating. Plasma-torch heating has some niche market applications. Other electrical heating options generally fall under the category of electrochemical processes: electrochemical batteries, electroplating, electro-refining, electrically driven lasers for focused heating and welding applications, and electro-barrier discharge reactors (or cool plasma). Together, these electrical heating options can help electrify the industrial sector.

Resistive heating is generally used to heat a small chemical reactor or a batch process. It requires only some form of resistance to electrical flow to generate heat that is dissipated to the chemical reactor vessel or reaction material in contact with the resistive material. Direct (Ohmic) heating involves passing current through a material to generate *in-situ* heat. Glass melting is one industrial process that takes advantage of the Ohmic heating of molten glass. Indirect heating simply passes current through an external resistance material and the heat generated is transferred to the reactor by conduction when heating a solid, the external surface of a chemical reactor, or the reactants in chemical reactors when a heating element or coil is used. Hot gases can easily be produced by convection when circulated in a resistively heated heat exchanger. Radiation heat transfer is invoked when a solid needs to be heated in an inert environment using a furnace.

Induction heating is currently used primarily in the metal industry for billet heating prior to forming or for surface-hardening techniques. The main advantages with this technique are rapid heating rates and a uniform heat flux that can be attained by inducing alternative currents in the body or industrial reactor process. The penetration, or depth and rate of heating, depends on the frequency and duration of the applied current. Larger units incorporate flux guides to provide an easy return path for magnetic flux, reducing the stray heating effects within the metal structure and also reducing the required power input. A number of chemical processes can be retrofit to apply induction heating by simply comingling the feed with a separable metal body or several metal bodies or by installing a fixed electrical conductor in the reactor that functions similar to a steam or hot-gas heating coil.

Dielectric heating can be effective when process reactants are molecules that respond to an electric-field alternating radio frequencies (10–30 megahertz [MHz]) or microwave frequencies (300–3,000 MHz). This technique applies strictly to non-conducting materials. The effectiveness of dielectric heating depends on the structure of the molecules subject to the effects of the applied electric field. Microwave heating is widely used in the food industry. The Federal Communications Commission (FCC) and the Food and Drug Administration (FDA) have approved two frequencies of microwaves for application to foods: 896 MHz and 2,450 MHz. For industrial-scale use, this microwave heating is mainly for drying applications. Radio-frequency heating is also common in the food industry, at FCC- and FDA-approved frequencies of 13.56, 27.12, 84.0, and 168 MHz. Both microwave and radio-frequency heating have been developed for coal and biomass drying (FDA 2015).

Energy penetration is more effective at microwave frequencies. Two types of microwave frequencies are authorized for industrial use in heating applications: serpentine applications (heating sheet materials with zig-zag path to introduce multiplicity of passes leading to high efficiency of energy usage and uniform heating) and multimode applicator (as used in domestic microwave ovens). Three types of radio-frequency applicators are commonly used: heating platen, stray-field electrode technique, and staggered-through-field system. Radio-frequency applicators contain an electrode system that, together with the material or product, forms a tuned circuit coupled indirectly to the generator output. The application selection determines the suitable process of radio and microwave frequency heating technique.

Infrared heating is common throughout industry. Hot resistance heaters emit radiation using emitters that operate above 2,000°C (Hewitt et. al. 1994). The main advantages of infrared heating are high rates of heat transfer, low heat losses (reduced capital on insulation required), and the elimination of potential contamination from fuel combustion. Infrared heating is best applied for flat surfaces or regular shapes, in general. The work piece or solid material must be in direct line of sight with the emitter, and large heating requirements or high process-throughput rates may be difficult to achieve.

Electric-arc process heating is accomplished when an arc is struck either between two electrodes or between one electrode and the chemical-reactor charge, which is generally a metal solid. When an air gap is subjected to very high voltage, electrostatic forces ionize the air in the gap. Ionized air behaves like a conductor, so the current starts flowing through the ionized gap, in the form of a continuous arc. The temperature of the arc may reach very high temperatures, between 3,000°C and 3,500°C, sufficient to melt any known metal. Appendix D shows that graphite electrodes are used to achieve high heat rates at temperatures around 2,200°C.

4.6 Thermal and Electro-Thermal Energy Storage

Thermal and electrical energy storage technologies can be used to balance the mismatch between energy production and use by industry. The type and scale of thermal energy storage depends on the quality of heat required by the process, the demand profile of the process-unit operations (i.e., batch or continuous), and the economics of heat production and storage. Thermal energy storage systems include traditional steam accumulators, solid- or liquid-state materials with high heat capacities, and phase-change materials that exploit the relatively high energy involved in melting or freezing a material. The goal is to store thermal energy whenever there is excess energy-generation capacity in the supply system—including excess electrical power generation potential on the grid. The stored energy is subsequently recovered when demand exceeds the capacity of energy-generation resources.

The basic principle behind steam accumulators is to inject steam into an insulated, pressurized accumulator tank when the demand for process steam is low. When the demand increases again, the steam is flashed and released for process heating, power generation, or CHP.

Brick, metals, and salt mixtures can theoretically be heated to any temperature that can be contained by the storage system, including beyond the melting temperature of the material if the system is designed to handle cyclic phase-changing. Heating can be accomplished by resistive, inductive, or convective methods. The cost of heat deposition, reservoir insulation, and operating and maintenance costs need be factored into the value proposition of the heat-storage system.

One concept referred to as Firebrick Resistance-Heated Energy Storage (FIRES) consists of an electrically heated firebrick stack (Forsberg 2015). Thermal energy is recovered from the brick stack by means of flowing air over the bricks or flashing water and superheating the saturated steam using channels or tubes running through the bricks in some fashion to extract the heat from the thermal mass.

Heat-circulation systems that are being developed for SMRs and SIPH are especially viable. Heat-storage reservoirs based on the CSP salts featured in Table 15 have already been developed and applied commercially in the United States and worldwide. The advantage of these heat reservoirs is the ability to circulate the molten salt to the process on demand. Liquid reservoirs can incorporate a closed-circuit heating coil linked to the heat source and a separate coil—closed or open circuit—linked to the process. In practice, one to several heat-circulation coils can be used to service plant thermal-heating needs or even to service a cluster of energy consumers.

4.7 Hybridization

Hybrid energy systems (HES) have been proposed as a solution to using the excess power generation capacity that exists on the electrical grid when the generation capacity exceeds demand periods. In the context of the national energy systems, the definition of a hybrid system is one that dynamically uses heat or electricity to optimize the financial efficiency of the systems by producing the highest value set of energy services and products throughout the year. These products include electricity, manufactured goods, and intermediate energy carriers that may be stored or directly used to produce the set of products. The value proposition of a "greenfield"[24] HES concept is currently being addressed by DOE, with an emphasis on regional scenarios that include a relatively high, hypothetical penetration of renewable energy (Bragg-Sitton 2016; Ruth et al. 2016a). A "brownfield" HES at an industrial site would involve the addition of a thermal energy generation source that is dynamically connected to the grid. Three scenarios presented by Ruth et al. (2016b) provide a general view of the basic system integration possibilities for clean thermal energy and power generation.

An HES differs from a co-generation system to the extent that the system maneuvers energy to optimize energy services based on the time-dependent value of these services. By comparison, co-generation systems are typically optimized to produce services at a constant rate or according to a schedule of service demands. CHP systems are designed to produce heat (usually steam) and electrical power to cover plant demands. Excess electricity produced by CHP systems is typically dispatched to the grid on a fixed schedule, although the amount of electricity sent to the grid may

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[24] A greenfield plant entails a capital investment for a new project, and all related permitting, new site preparation, construction, and start-up costs. A brownfield plant generally involves either a retrofit or an additional capital investment at an existing site and may involve a revision in plant operating permits.

also be increased when the value can justify throttling or even idling the manufacturing plant (i.e., hybrid operation).

The analysis by Ruth et al. (2016b) reveals that clean energy sources may economically displace with industry fossil-fired heat generation under the assumptions considered; however, the value position of hybrid operations will depend on the value of electricity. The role and cost of energy storage will also drive hybrid system deployment and operation considerations.

HES may connect to industry through energy storage and energy carriers that are produced using the excess power generation sources that are not tightly coupled to industry. Geographical separation, differences in SMR scales, and industrial operation cycles may be addressed with the production of an intermediate product. Potable water, hydrogen, and other intermediate chemicals such as methanol and ammonia are examples of intermediate products.

Seasonal energy use patterns are an important consideration for HES. For example, agriculture residues may be processed into energy products during or following the summer-to-fall harvest season. This conveniently corresponds to the fall period when electricity demand is at the lowest level for the year. Similarly, ammonia production during the spring could take advantage of the excess electricity generation capacity while producing fertilizers needed for spring and summer agriculture demands. The tradeoff of ammonia and fertilizer plant capacity factors and product storage associated with constant generation throughout the year should be taken into consideration in such cases.

4.8 Hydrogen

Hydrogen production was not identified from our analysis of GHGRP data as a major industrial emitter, but it is directly tied to oil refineries, ammonia production, and chemicals synthesis. As a clean energy fuel, hydrogen production and utilization could be increased. For example, hydrogen could be produced and stored for power generation in stationary fuel cells or for motive fuel in fuel-cell vehicles. Hydrogen production could be used to take advantage of the excess electricity generation capacity that often exists on an hourly, daily, and weekly basis. Hydrogen could be produced on a scale equivalent to the generation capacity of the grid when demand for electricity drops in the spring and fall. This could increase the utilization efficiency of the capital investment associated with both nuclear and renewable energy.

According to recent estimates, about 10 million tonnes of feedstock hydrogen are produced and consumed in the United States each year (EIA 2008). The analysis for this report indicates refineries consume about 50% or 5 million tonnes of this inventory for heavy oil hydrocracking and hydrotreating and for desulfurization of sour crude. The remaining share is produced and used for ammonia, methanol and other alcohol production, the food industry, metals refining, glass production, and electronics fabrication. A relatively small amount of hydrogen is currently used for fuel cells, either for material-handling forklifts or light-duty vehicles. This may change with greater penetration of fuel-cell vehicles and availability of hydrogen refueling stations. Additionally, increased production of hydrogen may provide the impetus for utility-scale power production using solid-oxide fuel cells (DOE 2015f) and hydrogen gas-combustion turbines (GE 2010).

Potential new industrial usage of hydrogen (and oxygen) could include:

- Small ammonia plants that are coupled to distributed hydrogen generation
- On-site production in petroleum refineries and for comparatively small biofuel plants
- Hydrogenation of CO_2 in chemicals and fuels synthesis
- Direct reduction of iron ore for clean iron and steel manufacturing
- Hydrogen combustion for heat and reducing atmospheres in glass and steel production
- Hydrogen-enriched flames for process heating and for combustion turbines.

Both domestic and worldwide need for ammonia (and the hydrogen necessary to produce it) could rise if nascent markets are realized for energy crops to produce biofuels and biopower. Additionally, new ammonia uses are on the rise, including use for nitrogen oxide selective catalytic reduction in coal and natural gas power plants and for diesel exhaust fluids that are now required for heavy-duty trucks and mining vehicles.

This report especially notes the high quantity of hydrogen used by the refinery industry (Appendix C). Refineries use hydrogen to hydrocrack heavy-vacuum residuals and oils, to hydrotreat heavy-gasoline distillates, to isomerize light-hydrocarbon fractions, and for crude desulfurization and denitrogenation when necessary to meet fuel specifications. About one-fourth of the requisite hydrogen is generated within the refinery in the reformer; the remainder is supplied from an external supplier, usually a natural gas reforming plant. In some areas, such as along the Gulf Coast, a hydrogen pipeline supplies merchant hydrogen to the refineries.

The advent of clean zero-carbon hydrogen would reduce the carbon emissions from refineries. Additionally, refinery plant emissions could be reduced by burning hydrogen in the numerous fired heaters and gas-vent flares throughout refineries, the majority of which are not equipped with pollutant controls given their size and intermittent operation.

Hydrogen production could also be used directly in the steel-making process to (1) reduce iron ore to “sponge” or “pig” iron, (2) purify the iron metal or cast-iron products, and (3) temper or anneal iron and steel products. Direct reduction of iron with hydrogen is a concept that has been proven to be technically feasible (Sohn 2007; Pinegar et al. 2011).

Biofuels production could also become a major consumer of hydrogen. Instead of generating ethanol, as discussed in Section 3.6.2, biomass resources could be converted into more carbon-rich synthetic liquid fuels such as refinery-compatible bio-oil. That process may utilize distributed processing of the biomass feedstock (Jones 2009).

Finally, hydrogen and oxygen that is co-produced when electrolyzing water can be used to enhance combustion throughout the industrial sector. Hydrogen-enriched natural gas is already going forward in Europe (Shahryar et al. 2014), and interest in the United States is growing with the understanding that hydrogen can be mixed and burned with natural gas by industry. This could reduce industry pollutant emissions without making significant changes to fired heaters and steam boilers.

Based on the data presented in Table 14, petroleum refineries use 9,130 tonnes/day of hydrogen. If hydrogen were used for the iron and steel mills instead of coke, 6,690 tonnes/day of hydrogen would be needed. Assuming a 150-MW_t LWR unit dedicated to producing hydrogen using high-temperature steam electrolysis, 309 SMR units would be required for the refineries and 226 SMR units would be used within the iron and steel mills.

5 Analysis Opportunities

This study highlights the GHG emissions associated with heat demands from the most significant industrial emitters and discusses in detail possible substitute clean heat sources such as nuclear reactors and SIPH. Geothermal heat sources—especially EGSs—also show large potential for heat application but face barriers of technology maturity and geographical separation of current and prospective geothermal sources from current industrial centers. In many cases, the clean energy sources could replace CHP systems. Some of these systems could operate in a hybrid manner as explained in this report and previous related reports.

Replacement of dedicated power-generation plants, fossil-fired steam boilers, and fired heaters with new steam and hot-gas production systems is possible throughout each of the target industries. The study also finds that direct electrical heating of heat-transfer fluids may be an effective mode of transferring isolated or remote clean-power generation sources and/or over-generation capacity to industry for process heating.

Thermal energy storage may be essential for application of SIPH or to manage variations and differences in grid electricity, industrial thermal energy profiles and scales of production, and industry heat-use needs. Thermal energy storage can be matched to the thermal energy requirements of the industrial user, through temperature boosting and using salt mixtures tailored to liquid-solid fusion temperatures sufficiently above the process operating temperature to deliver a constant heat flux.

Finally, hydrogen use by industry provides another route for imparting clean energy generation sources to industry. Hydrogen can be produced from clean energy sources and then stored on a small or large scale. It can directly replace a large fraction of natural gas and combustion of other carbon-bearing fuels. Hydrogen production from clean energy sources can take up excess energy on a large scale, thus supplanting traditional steam-methane reforming plants that generate GHG emissions. Large-scale storage is likely a key to providing a consistent source of hydrogen throughout the year.

The above findings and other observations found in this report give rise to the following list of analysis opportunities and technology development and testing:

1. ***Complete a detailed cost comparison and technical assessment of the potential for heat delivery from SMR, SIPH, and geothermal resources, respectively, with fossil-fuel combustion.*** This analysis could include an analysis of resource availability and siting issues. It could also include an assessment of the annual cost benefit and potential GHG emissions reductions of SMR, SIPH, and geothermal heat applications versus grid electricity to thermal energy conversion and storage, considering projected grid profiles and the industrial heat-use patterns highlighted in this report. This analysis may provide guidance on matching SMRs, SIPH, and geothermal plants to the various scales of industrial heat users—for example, heat classification of total thermal energy demand less than 1–10 MW_t, 10–100 MW_t, and greater than 100 MW_t. The practical temperature limits for SIPH and EGSs will govern the penetration of these heat sources.

2. ***Complete case-specific heat application design studies to evaluate heat integration using engineered designs that provide a basis for capital and operating cost expenses to***

be evaluated. This activity will help establish the business case for some realistic cases and possibly will provide greater impetus for commercial pull. The effort would likely be most effective with industry collaboration to help identify the leading deployment opportunities.

3. ***Conduct heat-transfer tests for representative industry reactor vessels with hot gases, organic heat-transfer fluids, and other heat-transfer media, including energy deposition in existing process reaction vessels and heat exchangers.*** This effort may include evaluation of new reactor technologies, such as compact heat-exchanger reactors, that could help improve process intensification and efficiency.

4. ***Given the temperature limitations of SMRs, SIPH, geothermal resources, and heat-transfer systems, complete a technical evaluation and the cost benefits of heat-boosting concepts.*** This activity may consider heat-topping options—for example, electrical heating, hydrogen combustion, and chemical heat pumps. It may consider heat boosting through electrical heating of solid media, eutectic salts, molten salts, or liquid metals.

5. ***Evaluate the feasibility of retrofitting existing CHP power turbines with SMR, SIPH, and geothermal heat-supply sources.*** This activity may also encompass the costs and benefits of maintaining existing reciprocating energy CHP plants on emergency standby or for intermittent operation.

6. ***Determine the scale and cost of thermal energy storage buffers—for example, steam accumulators, molten-salt heat reservoirs, process-specific/custom-designed eutectic salt or adsorption/desorption energy storage media, and solid heat-storage media.*** This effort may lead to new or advanced technology concepts for heat storage by electrical heating. Thermal energy storage concepts developed for concentrating solar systems may be applicable to industry thermal energy reservoirs. Other thermal energy concepts have also been recently proposed. In addition to cost considerations, the thermal dynamic properties of the storage systems and the industrial heat-duty requirements and heat-transfer physics need to be considered.

7. ***Complete a study of current versus future opportunities to develop energy parks.*** This analysis effort may evaluate heat-distribution costs as a function of distance to plant. It may also evaluate the costs and benefits of economies of scale for SMRs, SIPH, and geothermal options. A variety of manufacturing centers (or energy clusters) may already be suitable for a notional energy park. Future industry replacements or new growth may embrace energy parks surrounding renewable and nuclear energy that may have relatively low operating costs.

8. ***Evaluate the techno-economic feasibility of potential industry operations that may be best served in hybrid energy systems.*** Unit operations that may optimize year-round, online operating capacity of SMRs, SIPH, and geothermal systems may include the following industrial plants:

    a. Food processing and/or dehydration and packaging

   b. Conversion of seasonal biomass to intermediate or final products, including biomass drying and stabilization, pyrolysis oil production and stabilization, and increased ethanol production

   c. Industry waste-water cleanup or brackish-water desalination and storage

   d. Hydrogen generation and storage

   e. Intermediate chemical commodities, including synthetic natural gas, methanol, ethylene, and ammonia

   f. Pumped hydro and compressed-air storage.

   Including seasonal energy-use patterns would improve this analysis. In addition, energy-delivery reliability, capital-use optimization, and overall system costs and benefits may be evaluated.

9. ***Evaluate relative cost-benefit tradeoffs of electrification of industry.*** This study could illustrate the spatial availability and energy concentration of renewable energy sources (wind, solar, geothermal, and marine hydrokinetic energy) and compare it to the nation's manufacturing centers. It is motivated by the location of U.S. manufacturing plants (distributed mainly throughout the Eastern states region to the Upper Midwest, and stretching down to the Gulf Shores) as compared to the best-class wind, solar concentrating, and geothermal resources, which are located at the edge of the Midwest, the Southwest, and the Intermountain and coastal mountain areas, respectively. Electrification/electrical heating can ameliorate the geographic separation of renewable and industry. Interest in electrochemical and electrocatalysis processes is also on the rise, as referenced in this report, to produce not just inorganic chemicals such as chlorine and alkalies but also basic organic compounds. An additional aspect of the analysis is heat deposition by electromagnetic heat transfer because it is pertinent to process intensification.

   Moreover, this report reveals that 75% of industry GHG emissions originate outside of the identified target industries' 960 large-emitting plants. Most of these emissions come from small manufacturing plants whose annual emissions are less than 25,000 tonnes CO_2e. While small-scale thermal energy systems provided by SIPH or geothermal systems may apply to these plants, electrification could be more cost effective.

10. ***Perform a techno-economic assessment of hydrogen production for supply to industry and the transportation sector and compare hydrogen production and storage on a large scale considering seasonal power-demand profiles.*** The potential merits of hydrogen as an energy storage and substitute for fossil-fired heating operations, petroleum and biofuels production, and use as a reductant in metals manufacturing infer that a national-scale hydrogen production system can help optimize the capital operating efficiency of nuclear and renewable power generation. The value of hydrogen and other chemicals (e.g., CH_4) production relative to power production may be included in this assessment.

11. ***Evaluate the cost and benefits of repurposing biomass waste residuals for transportation fuels production or high-temperature reaction processes such as cement, lime, and steel making.*** For example, alternative process operations to convert black liquor into transportation fuels or commodity chemicals—with provisions to recover soda ash—could be considered.

12. ***Evaluate the impact on U.S. economic competitiveness in terms of supply-chain industry and workforce needs to implement the mass use of clean energy sources.*** The demonstrated strength of U.S. manufacturers in the post-recession years in terms of output growth, competitiveness relative to other U.S. economic sectors, productivity growth, and expansion of U.S. multi-national corporations (Moran and Oldenski 2014) could lead to reshoring manufacturing production and an overall expansion of domestic manufacturing. Recent federal efforts, such as the NNMI Program (AMNPO 2015) and DOE's CEMI (DOE 2015g), have aimed at further increasing the strength of domestic manufacturing. For perspective, replacement of 10 EJ (9.5 quads) of industry energy (or just one-third of the current annual energy demand by industry, and one-fourth of projected industry energy demand of 39.5 EJ [37.4 quads] in 2025) requires over two hundred 150-MW (thermal) class SMRs (viz., 235 reactors with 0.9 online operating capacity). Reshoring manufacturing could require a supply chain of high-purity metals and metal alloys, metal materials production, pressure vessel and pipe manufacturing, instruments and controls supply, and all manner of related plant construction and permanent operator positions. It could also require an expanded nuclear fuels market and solar-reflector commercial manufacturing and installation.

6 Conclusions

This report provides a complement to analysis of process-efficiency improvement by considering how clean energy delivery and use by industry could reduce GHG emissions. It specifically considers the possibility of replacing fossil-fuel combustion in industry with nuclear, SIPH, and geothermal energy sources. The possibility of applying electrical heating and greater use of hydrogen is also considered. This work is unique and points to the need for further analysis.

The EIA projects that total U.S. energy consumption will grow to about 108 EJ (102 quads) in 2025, with nearly all of the growth coming from the industrial sector (DOE 2015b). Annual energy consumption in the industrial sector is forecast to increase to 39.5 EJ (37.4 quads)—a 22% increase, exceeding 36% of total energy consumption in the United States.

The industrial sector was the third-largest source of direct U.S. GHG emissions in 2014, behind electricity generation and transportation, accounting for roughly 20% of total emissions (EPA 2016). Fuel combustion results in about 52% of U.S. industrial direct GHG emissions and is largely driven by the demand for process heating, process reactions, and process evaporation; concentration; and drying. As a result, mitigating industrial direct GHG emissions will involve changes to how heat demands are met.

This report assimilates EPA GHGRP-reported emissions data and GHG emissions factors to calculate thermal energy demands at a resolution not previously available to the public. Fourteen key industries, comprising 960 facilities (0.33% of all U.S. manufacturing facilities), with the relatively highest annual GHG emissions were selected for assessment of their emission characteristics and thermal heat duties. The calculated combustion energy use in 2014 by these industries was 5,824 PJ (5.5 quads)—equivalent to nearly 50% of combustion energy in 2010 reported by EIA MECS and 5% of U.S. total GHG emissions in 2014.

The thermodynamic nature, scale, and heat-use patterns of representative facilities were evaluated for each target industry. The common feature of these industries is they convert raw materials into energy services by means of physical and chemical changes. These changes generally require thermal energy to affect solids and liquids heat-up, melting, and evaporation and to heat up reactants to initiate molecular bond breaking and to sustain the propagation of chemical reactions. Heat demands range from low-temperature steam (50°C, 0.7 MPa) used for steeping in corn wet milling up to high-temperature-unit operations (up to 1,500°C) used for heating cement kilns. The scale of heat demand for the average facility ranges from a heat input of 1.76 TJ/day (1,700 MMBtu; or 21 MW) for production of 11,000 bpd ethyl alcohol to 26 TJ/day (25,000 MMBtu; or 300 MW) for roughly 5,000 tonnes per day of potash, soda, or borate mining and processing. Discussion of additional technical characteristics and considerations is provided in the main body of the report and the appendices.

The practical limit of clean heat sources depends on the temperature output of the source. Current high temperature gas-cooled SMRs can provide upwards of 850°C, and with materials development, 950°C may be attainable with demonstration of metal alloys performance at these temperatures. For industrial heat duties above these temperature thresholds—such as required for cement mineral calcination—it may be necessary to substitute fuels derived from biomass, including biomass char or synthetic natural gas produced from biomass, to supplant the fossil fuels that are currently combusted to achieve temperatures approaching 1,500°C.

Substitution of one-third of the projected 2025 industrial energy demand could be met by about 235 SMRs with a capacity rating of 150 MW_t forecast. This study indicates the scale of the largest industrial energy users is amenable to the scale of SMR applications. SIPH and geothermal energy could readily supply future industrial heat demand; however, the best solar insolation and identified geothermal sites are distant from most of the current industrial centers.

Further analysis is warranted to identify and quantify opportunities for conversion of industrial thermal energy requirements to clean energy. Some of those analyses are listed in Section 5.

Several technical challenges and opportunities to application of clean energy sources for industrial heat users were identified and are discussed in this report, including:

- Quality of heat required by the user (or temperature of the working fluid)
- Industry process heat-transfer modes
- Scale of heat source versus heat user demand, which may be mitigated by selecting the appropriate source or by industrial clustering (also referred to as an energy park)
- Transport requirements between the heat source and industrial process-unit operations, which involves distance and the materials needed for that transport
- Thermal energy storage needs and options
- Hybrid heat/electricity production.

The following list is an abbreviated summation of the report observations and finding:

1. Fourteen industries were selected for process-level thermal analysis. In 2014, 960 plants representing these industries reported emissions under the GHGRP. They constitute less than 0.5% of all U.S. manufacturing facilities but are responsible for nearly 25% of U.S. GHG inventory industrial-sector emissions, which equates to 5% of U.S. total emissions in 2014. Most of the remaining 75% of industrial GHG emissions is therefore tied to smaller facilities that fall under the EPA reporting limits for large GHG emitters.
2. Calculated combustion energy use in 2014 by the 14 target industries was 5,824 PJ or 5.520 quads—nearly 50% of 2010 manufacturing combustion energy use estimated by the MECS.
3. Within those 14 industries, CHP and conventional steam boilers account for about 70% of the heat loads. Those and other fossil-fired heating systems could be substituted by clean heat sources generating steam, hot gas, and heating other heat-transfer media. Options for clean heat sources include emerging SMRs, SIPH, and geothermal sources, as their scales are applicable to individual industry needs.

4. Most process heating within these 14 industries is accomplished with steam jackets, heating coils, and indirect heat exchangers that transfer heat from a hot gas (generally combustion gases) to the process reactor. Clean heating systems could replace the combustion gas systems by using heat circulation systems such as those described in this report.
5. Several industrial heat users, such as oil refineries, pulp/paper manufacturing, methanol, fertilizer plants, corn wet milling plants, and some inorganic mineral plants, have duties in excess of 10 TJ/day (9,500 MMBtu; 120 MWt). SMR technologies are expected to be well-matched to this scale of demand.
6. SIPH applications could potentially supply heat to the majority of the industrial applications analyzed here. Specific examples include chlorine/alkali plants, certain chemical production plants, and food processing plants. Currently, all of the major concentrating solar projects in the United States are in the Southwest, with a few in Florida and Hawaii. Technical and economic feasibility of SIPH systems for industrial heating depend on solar insolation at—or nearby, based on heat transport opportunities—the location of the facility, as well as space available for concentrating solar energy systems and heat storage systems.
7. Geothermal energy could provide thermal energy to food processing plants and to plants that use lower-temperature heat to concentrate and/or dry process feedstocks and products, such as wet corn milling. Current geothermal energy production techniques for thermal applications usually provide lower-temperature energy (typically ranging from 50–150°C) than is required by many manufacturing industries. EGSs that could achieve higher-temperature output are currently being developed.
8. The design of heat transport from SMR and SIPH sources to the industrial user may be optimized with a heat circulation system that uses a liquid heat transfer media—such as a molten salt or Dowtherm™—to deliver thermal energy over relatively long distances. Heat transfer to a hot gas or steam loop may then optimally interface with the heating coils or boiler tubes that are used in most industrial processes.
9. Heat recuperation and temperature boosting are important thermal energy management concepts that may benefit SMR, SIPH, and geothermal energy sources. For example, high-temperature heat pump concepts, including adsorption/desorption chemical cycles or renewable hydrogen could help boost the temperature of heating media.
10. Hybrid thermal/electricity generation may help balance hourly, daily, and/or seasonal electrical cycles. Seasonal heat load opportunities include food processing and/or dehydration, conversion of biomass to intermediate products by drying, torrefaction, pyrolysis oil production and stabilization, ethanol production, hydrogen production, industry waste-water cleanup or brackish-water desalination, and pumped hydro and compressed-air storage.
11. Intermittent or batch plant operations may require thermal energy storage systems that match clean energy delivery with thermal load schedules.

12. Electrification of industry warrants further consideration. Thermal energy storage concepts such as those being developed for concentrating solar systems may help coordinate grid profiles with industry heat use profiles. Direct electrical heating is technically feasible but could add to grid-response dynamics and challenges.

13. Hydrogen production for use as a substitute fuel gas by industry could reduce industry GHG emissions. Hydrogen could also replace carbon that is used as a reducing agent in steel manufacturing. Hydrogen that is produced by water splitting would provide carbon-free hydrogen for these uses.

14. SMRs were identified as an option for process heat and hydrogen production for feedstock use. The number of SMRs theoretically required to meet the heat and hydrogen requirements of applicable target industries was estimated. The potential number of SMRs that could be built may be limited to siting restrictions and licensing restrictions. A similar analysis to estimate the theoretical number of geothermal and SIPH plants was not conducted because of large variability in available heat capacity.

    a. To supply heat to industry and hydrogen as feedstock to refineries, steel production, and plastic materials and resins production, 850 SMRs, rated at 150 MW_t, would be necessary. More would be needed if industries with a heat duty under 150 MW_t are located in a cluster. This report identified opportunities to use approximately 314 SMRs to supply 1,480 PJ/yr of heat ranging up to 850°C. This heat potential does not include hydrogen combustion because SMRs were assumed to supply hydrogen for feedstock use only. The pulp and paper and petrochemical industries have suitable temperature ranges but were excluded from this total due their reliance on process byproducts as combustion fuels.

    b. Petroleum refineries use 9,130 metric tonnes/day of hydrogen. All of the refinery merchant hydrogen demand could be met by 309 light-water SMR modules.

    c. Substitution of hydrogen for coke in U.S. steel production would use an additional 6,690 metric tonnes/day of hydrogen. All of the merchant hydrogen for the steel industry could be met by 226 light-water SMR modules.

15. SIPH and geothermal energy systems are theoretically scalable to any load. Commercial systems for SIPH range from 100 kW_t for small industries to approximately 1,000 MW_t for CSP systems. SIPH and geothermal energy may be impractical in some locations due to resource quality.

    a. SIPH could theoretically supply up to 1,480 PJ/yr to 8 of the 14 target industries identified in this report before considering practical temperature and spatial constraints. The pulp and paper and petrochemical industries have suitable temperature ranges but were excluded from this total due their reliance on process byproducts as combustion fuels.

    b. By comparison, geothermal systems that can provide a heat supply media at 150°C could provide up to 70 PJ/yr to the wet corn milling industry.

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Appendix A. Description of Target Industries

Table A-1. Description of Target Industries

Target Industry	NAICS Code	Description
Petroleum Refineries	324110	Establishments primarily engaged in refining crude petroleum into refined petroleum. Petroleum refining involves one or more of the following activities: (1) fractionation; (2) straight distillation of crude oil; and (3) cracking.
Iron and Steel Mills	331111	Establishments primarily engaged in one or more of the following: (1) direct reduction of iron ore; (2) manufacturing pig iron in molten or solid form; (3) converting pig iron into steel; (4) making steel; (5) making steel and manufacturing shapes (e.g., bar, plate, rod, sheet, strip, wire); and (6) making steel and forming tube and pipe.
Paper (Except Newsprint) Mills	322121	Establishments primarily engaged in manufacturing paper (except newsprint and uncoated groundwood paper) from pulp. These establishments may manufacture or purchase pulp. In addition, the establishments may also convert the paper they make.
Paperboard Mills	322130	Establishments primarily engaged in manufacturing paperboard from pulp. These establishments may manufacture or purchase pulp. In addition, the establishments may also convert the paperboard they make.
All Other Basic Organic Chemical Manufacturing	325199	Establishments primarily engaged in manufacturing basic organic chemical products (except aromatic petrochemicals, industrial gases, synthetic organic dyes and pigments, gum and wood chemicals, cyclic crudes and intermediates, and ethyl alcohol).
Ethyl Alcohol Manufacturing	325193	Establishments primarily engaged in manufacturing nonpotable ethyl alcohol.
Wet Corn Milling	311221	Establishments primarily engaged in wet milling corn and other vegetables (except to make ethyl alcohol). Examples of products made in these establishments are corn sweeteners, such as glucose, dextrose, and fructose; corn oil; and starches (except laundry).
Plastics Material and Resin Manufacturing	325211	Establishments primarily engaged in (1) manufacturing resins, plastic materials, and nonvulcanizable thermoplastic elastomers and mixing and blending resins on a custom basis, and/or (2) manufacturing noncustomized synthetic resins.
Petrochemical Manufacturing	325110	Establishments primarily engaged in (1) manufacturing acyclic (i.e., aliphatic) hydrocarbons such as ethylene, propylene, and butylene made from refined petroleum or liquid hydrocarbons, and/or (2) manufacturing cyclic aromatic hydrocarbons such as benzene, toluene, styrene, xylene, ethyl benzene, and cumene made from refined petroleum or liquid hydrocarbons.
Alkalies and Chlorine Manufacturing	325181	Establishments primarily engaged in manufacturing chlorine, sodium hydroxide (i.e., caustic soda), and other alkalies often using an electrolysis process.
Pulp Mills	322110	Establishments primarily engaged in manufacturing pulp without manufacturing paper or paperboard. The pulp is made by

Target Industry	NAICS Code	Description
		separating the cellulose fibers from the other impurities in wood or other materials, such as used or recycled rags, linters, scrap paper, and straw.
Lime Manufacturing	327410	Establishments primarily engaged in manufacturing lime from calcitic limestone, dolomitic limestone, or other calcareous materials, such as coral, chalk, and shells. Lime manufacturing establishments may mine, quarry, collect, or purchase the sources of calcium carbonate.
Nitrogenous Fertilizer Manufacturing	325311	Establishments primarily engaged in one or more of the following: (1) manufacturing nitrogenous fertilizer materials and mixing ingredients into fertilizers; (2) manufacturing fertilizers from sewage or animal waste; and (3) manufacturing nitrogenous materials and mixing them into fertilizers.
Potash, Soda, and Borate Mineral Mining	212391	Establishments primarily engaged in developing the mine site, mining and/or milling, or otherwise beneficiating (i.e., preparing) natural potassium, sodium, or boron compounds. Drylake brine operations are included in this industry, as well as establishments engaged in producing the specified minerals from underground and open pit mines.

Source: U.S. Census Bureau, n.d.

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Appendix B. Calculated Energy by End Use and Target Industry in 2014

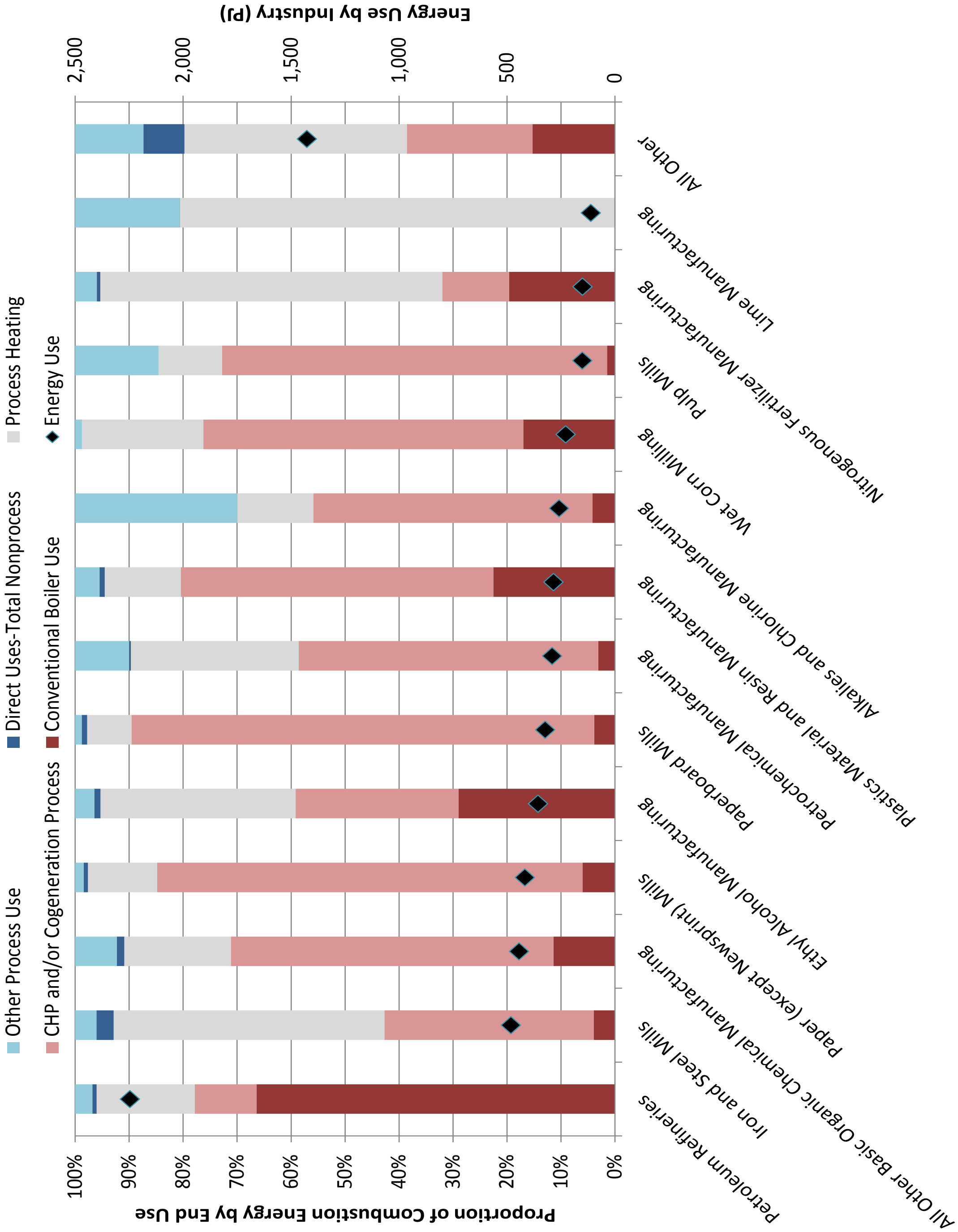

Figure B-1. Calculated energy by end use and target industry in 2014

Appendix C. Petroleum Refinery

Currently, there are 139 operating refineries in the United States. Most are located along the Gulf Coast with California taking the next largest cluster. Each day, 18 million barrels of crude oil are processed (EIA 2016). A summary of a typical refinery is shown in Figure C-1. The data for the following figures and tables primarily come from a report by the National Energy Technology Laboratory (Skone and Gerdes 2009). Additional data are taken from Olson (2014) and a report on a Chevron refinery (Chevron 2014).

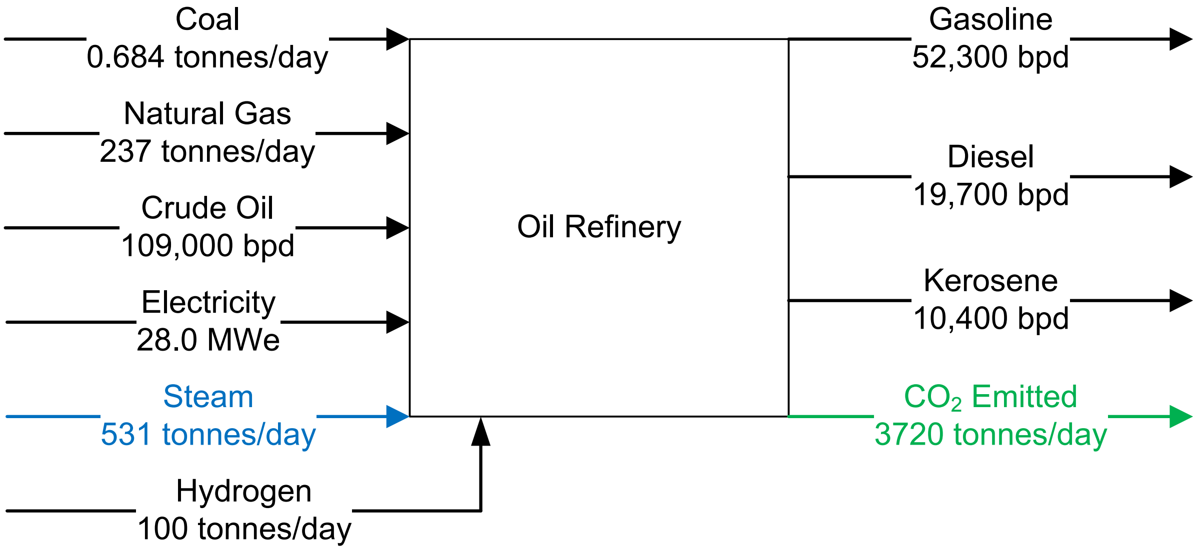

Figure C-1. Overall material and energy flows for a nominal crude oil refinery

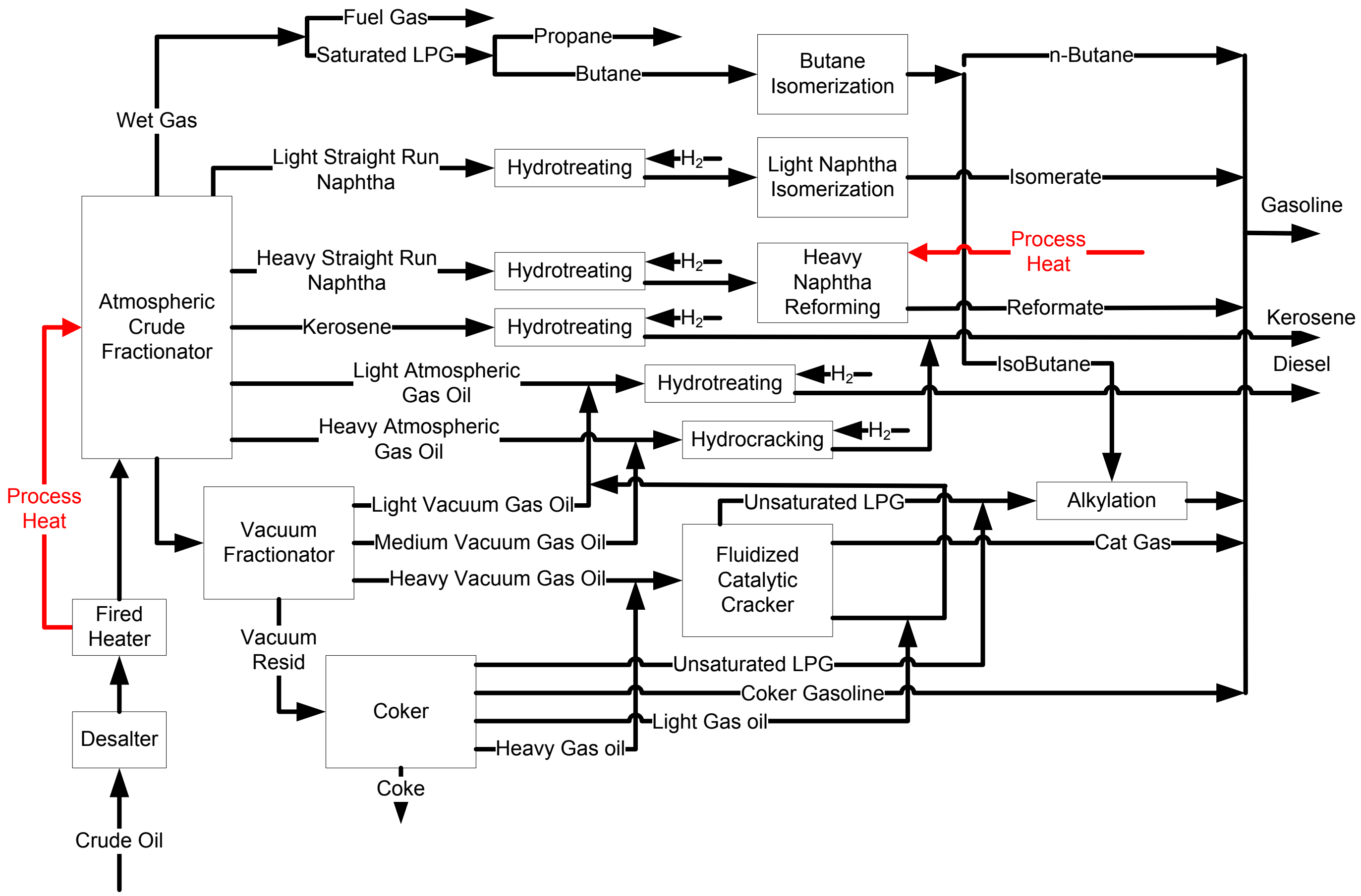

Figure C-2. Schematic of oil refinery process

Description

- **Desalter:** Water is added to the crude oil to dissolve the salts within. The brine is separated from the oil using electric grids. Salts are removed to mitigate vessel and piping fouling and corrosion.
- **Fired Heater:** The desalted oil is preheated by several heat exchangers and a fired heater. Up to 50% of the heat comes from products and side-cuts of the refinery process through recuperative heat exchange, the remaining heat comes from the fired heater. The oil is heated between 340 and 370°C.
- **Atmospheric Crude Fractionator:** The fractionator separates the crude oil into fractions or cuts based upon the boiling point ranges of the components. Lighter fractions come off the top with increasingly heavier components pulled further down the tower. Table C-1 shows typical cut points for components exiting the fractionator. Typically, the cut point temperatures do not change; however, the mass flows for each component are dependent on the feedstock. Each side draw feeds a stripping column that uses steam to control the initial boiling point. The process fluid partially vaporizes to establish vapor-liquid equilibrium. The side draws are used to preheat the crude oil.

- **Vacuum Fractionator:** Downstream of the atmospheric fractionator, the vacuum fractionator operates under a vacuum to separate the heavy, higher boiling point components. The vacuum decreases the boiling temperatures of the components. The temperature reduction will prevent the initiation of thermal cracking.
- **Gas Concentration Unit:** The light gases coming from the atmospheric fractionator are concentrated and separated within the gas concentration unit. Typically, they are separated as wet streams called liquefied petroleum gas (LPG), comprised of propane and butane and dry gases such as ethane and methane. The separation process is accomplished through distillation columns. The dry gases are typically used as fuel throughout the refinery for fired heaters and boilers. Purchased natural gas supplements this fuel as needed.
- **Fluidized Catalytic Cracker:** The fluidized catalytic cracker (FCC) breaks long chain hydrocarbons such as heavy gas oil into shorter chains such as naphtha. The endothermic cracking reactions occur at temperatures from 480 to 540°C and are fueled by the heat produced during catalyst-regeneration. About 5% of the feed ends up as coke; therefore, air is used in the regenerator to burn the coke off. The exit temperatures of the regenerator are between 925 to 815°C. A fractionator column is used downstream of FCC to separate and recover the hydrocarbon vapors.
- **Alkylation Unit:** The alkylation unit mixes olefins produced in the FCC unit with isobutene to form alkylate. Alkylate is blended with gasoline to raise its octane rating.
- **Butane Isomerization:** Isobutane gives a better octane level to alkylate than n-butane. For this reason, the isomerization process converts isobutene using excess hydrogen and a catalyst. A distillation column separates n-butane from isobutane.
- **Light Naphtha Isomerization Unit:** The light naphtha isomerization unit converts n-pentane and n-hexane into isopentane and isohexane in the presence of excess hydrogen and a catalyst. A distillation column removes butane and lighter gases.
- **Heavy Naphtha Reformer and Hydrotreater:** The heavy naphtha reformer increases the gasoline octane rating by converting naphthenes into aromatics and generating a reformate gasoline product. The reforming process is endothermic using three to four reactors and a fired heater. The reforming process produces hydrogen, which is used by the refinery's hydrocracking and hydrotreating processes. Hydrotreaters throughout the refinery process are used to remove impurities such as sulfur, nitrogen, oxygen, metallic salts, olefins, and some aromatics. Hydrotreaters do not affect the boiling range of the feed.
- **Hydrocracking:** Hydrocrackers use hydrogen to maximize ultra-low-sulfur diesel and jet fuel. Hydrocrackers operate at pressures of about 20 MPa, which requires expensive equipment. The hydrogen usage requires a hydrogen generation unit or hydrogen purchase. The cracking reactions are endothermic but concurrent hydrotreating reactions make the overall process exothermic. Reactor temperatures range from 290 to 450°C. The addition of hydrogen increases the production of isoparaffins and limits the production of olefins. A fractionator is used to separate the light gases, gasoline, and diesel.

- **Delayed Coking and Asphalt Production:** The delayed coker cracks heavy feedstocks to produce solid coke and light hydrocarbons that are blended in gasoline. The bottoms from the vacuum fractionator are combined with steam to a fired heater and then to an online coke drum.

Table C-1. Typical Cut Points for Atmospheric and Vacuum Fractionators

Component	Cut Temperatures (°C)
Atmospheric Crude Fractionator	
Light straight-run (LSR) naphtha	32–88
Heavy straight-run (HSR) naphtha	88–166
Kerosene	166–249
Light atmospheric gas oil (LAGO)	249–321
Heavy atmospheric gas oil (HAGO)	321–427
Vacuum Fractionator	
Vacuum gas oil (VGO)	427–566
Vacuum-reduced crude (VRC)	>566

Table C-2. Refinery Results

Crude Oil Refinery Results	
Inputs	
Crude oil (barrels per day)	190,000
Natural gas (tonnes/day)	237
Coal (tonnes/day)	0.684
Hydrogen (tonnes/day)	100
Electricity (MWe)	28.0
Steam (tonnes/day)	531
Products	
Gasoline (barrels per day)	52,300
Diesel (barrels per day)	19,700
Kerosene (barrels per day)	10,400
Fuels Produced and Used by Refinery Process	**(barrels per day)**
Liquefied petroleum gases	76.8
Distillate fuel oil	13.9
Residual fuel oil	40.6
Still gas	4,380
Petroleum coke	1,650
Other petroleum products	98.0
CO_2 Emissions	
Emitted (tonnes/day CO_2)	3,720
Heat Produced from External Sources	**(terajoules/day)**
Natural gas	11.3
Coal	0.0209
Steam	1.37

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Appendix D. Iron and Steel Mills

Iron and steel manufacturing are some of the most energy-intensive industries worldwide. In 2008, the U.S. iron and steel industry consumed a total of 1,466.52 PJ[1] of energy for producing 93.7 million tonnes of steel (Worrell et al. 2010). Two processes are mostly used for production of steel: traditional reduction of iron ore and recycling of scrap metal. Iron ore is used to produce plate and ductile iron products that require "cold working" and high tensile strength. It is also used for iron steel alloy. Scrap metal recycling is used to produce lower-quality steel, including structural beams, reinforcing bars, and other products that require a minimal amount of cold working.

In the iron ore reduction process, sintered or pelletized iron ore (mainly iron oxides found in magnetite, hematite, and limonite) is reduced in a blast furnace using coke, combined with injected coal or oil, and with limestone, which is used as a fluxing agent to produce pig iron in a blast furnace. The purpose of the blast furnace is to chemically reduce and physically convert iron oxides (raw ore, pellets, or sinter) into molten iron, also referred as hot metal. Reducing gases (hydrogen and CO) are produced by partial combustion of the coke. For steel production, the carbon content in iron is reduced and other elements such as manganese and nickel are added to give specific/desired properties to steel. Direct reduction of iron ore is also becoming popular given the volatility of coke and to address concern for CO_2 emissions from coking ovens. Natural gas and hydrogen gas mixtures are effective at reducing iron ore.

Recycled scrap metal steel production requires adding scrap metal to an electric arc furnace. The emissions from the electric-arc process are much lower compared to the traditional reduction of iron ore, but the emissions depend on the source of electricity and graphite electrode burn-off. Even though the United States has built numerous small steel recycling plants, there is no additional projected growth. High demand for scrap metal has created a shortage in supply that will likely continue to suppress the recycled scrap metal market in the future.

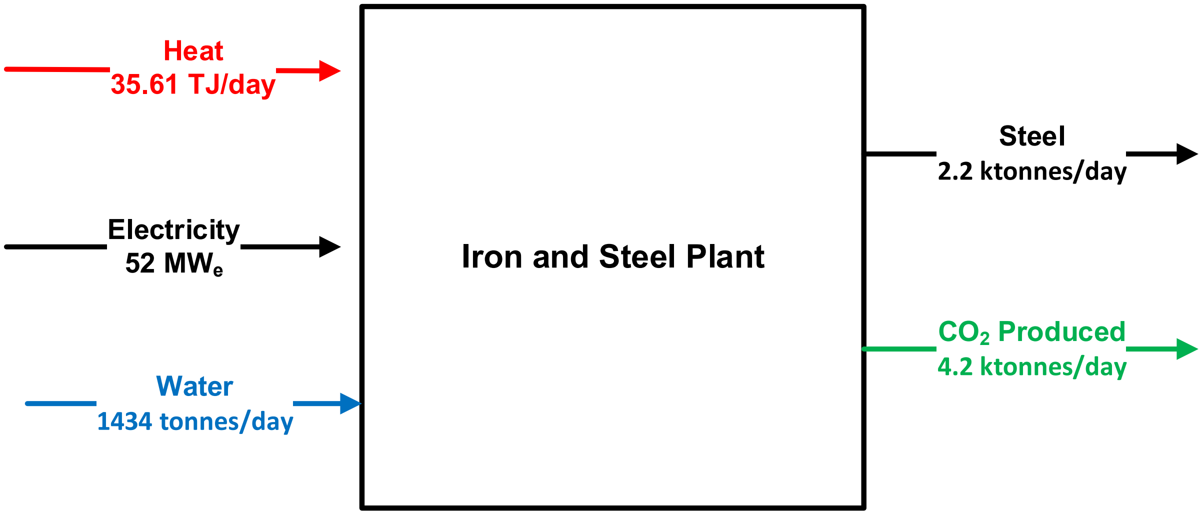

Figure D-1. Material and energy flows for a nominal iron and steel production plant

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[1] 1 PJ = 1,000 TJ

Process

Iron and steel production is a very energy intensive process. As shown in the process flow diagram (Figure D-2), the main input feeds for making 1 tonne of pig iron are approximately 2 tonnes of ore, 1 tonne of coke, 0.5 tonne of limestone, and 3.5 tonne of air. Iron oxides enter the blast furnace in the form of ore, pellets, or sinter. Sintering is essential to improve the permeability of the oxides in the blast furnace and to make it easier to reduce. The product obtained from the blast furnace is a hot metal (pig iron), which contains 3–4% carbon and some other impurities. The crude steel produced reduction of iron ore and recycled scrap is cast into ingots and subsequently reheated and rolled to produce billets and slabs. Essential steps in iron and steel production are broken down as follows:

Coke Production: This process carbonizes coal with high temperatures (around 1,100°C) in an oxygen-deficient atmosphere. The purpose of processing is to provide heat, necessary for attainment of desirable chemical equilibriums and adequate rates of reaction, and to provide gas-reduced CO for reduction of iron oxide.

Blast Furnace: The blast furnace is lined with refractory firebrick, which allows the furnace to maintain a high temperature. In the furnace, limestone is added as a flux to react with principle impurities (such as alumina and silica), to form a slag that is lighter than the molten iron, that floats on the latter in the furnace bottom. The main feed (input) goes through various chemical and physical reactions while descending to the bottom of the furnace (American Iron and Steel Institute 2015):

$$3\ Fe_2O_3 + CO \rightarrow CO_2 + 2\ Fe_3O_4 \qquad \text{(begins at 455°C)}$$

$$Fe_3O_4 + CO \rightarrow CO_2 + 3\ FeO \qquad \text{(begins at 594°C)}$$

$$FeO + CO \rightarrow CO_2 + Fe \qquad \text{(begins at 705°C)}$$

or

$$FeO + C \rightarrow CO + Fe$$

The coke introduced at the top of the furnace descends to the bottom where hot blast air enters the blast furnace, igniting the coke and producing CO_2 and heat. Because this reaction takes place in the presence of excess carbon, the CO_2 reduces to CO, which is necessary to reduce the iron ore (as shown in the equations above) to produce hot metal.

Basis Oxygen Process/Furnace: In this process, the hot metal and steel scrap are oxidized to remove impurities, and air is replaced by pure oxygen at a pressure of 0.965–1.241 MPa. The oxygen then produces iron oxide in the melt, oxidizes carbon, and evolves the CO and CO_2. Fluxing agents (lime and fluorspar) are added, which help form the slag that is removed with liquid steel. Gases and slag particles reaching the outlet gas stream are scrubbed before being exhausted to the atmosphere.

Electric Arc Furnace Process: This process is a batch-melting process producing batches of molten steel known as “heats.” The process was originally solely used to make high-quality steel, such as that used for machine tools, as this process gave more precise control over the composition. In this process, rough electrodes are heated to 2,204°C, which converts the coke to graphite (American Iron and Steel Institute 2015). Rough electrodes (also known as *graphite electrodes*) provide high levels of electrical conductivity to help sustain high-heat rates. As melting of hot metal occurs, the electrodes burn, creating a molten metal. A slag is formed from the oxidized impurities and reaction with the lime. After this, the slag and liquid steel are collected separately.

Table D-1 provides a detailed breakdown of steel production energy requirements and emissions.

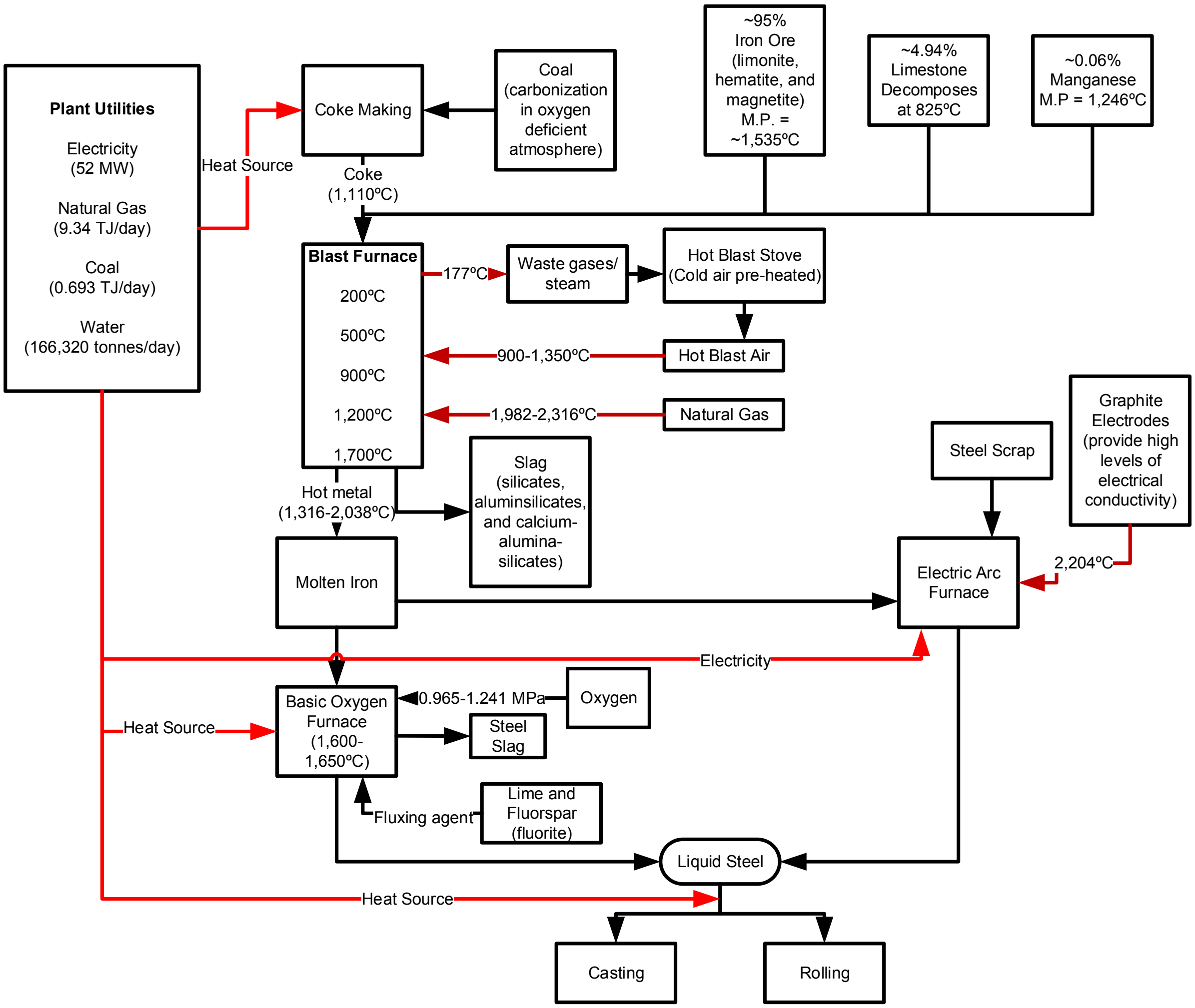

Figure D-2. Iron and steel production process flow diagram

Table D-1. Net Energy Inputs and Emissions for Steel Production

Net Steel Produced (2008)	**93.7 Mt**	
Number of Facilities in the United States	116	
Blast Furnace Energy Balance (Hot Metal)		
Energy Input (TJ)		%
Sensible Heat of Hot Blast	1.54E+05	41
Combustion of Coke	1.97E+05	52
Combustion of Injected Fuel	2.53E+04	7
Total	**3.76E+05**	**100**
Energy Output (TJ)		%
Reduction of Iron Oxides	1.10E+05	29
Reduction of other Metalloids	1.41E+04	4
Sensible Heat of Slag	4.50E+04	12
Sensible Heat of Hot Metal	1.27E+05	34
Sensible Heat of Top Gas	1.87E+04	5
Decomposition of H_2O at Raceway	2.44E+04	6
Vaporization of H_2O from Burden	1.22E+04	3
Heat Losses	2.44E+04	6
Total	**3.76E+05**	**100**
Inputs: Utility Summary (Iron and Steel)		
Total Energy Consumption Iron and Steel, 2008 (PJ)	1,467	
Avg. Energy Consumption Iron and Steel per Facility, 2010 (PJ)	13	
Power Requirement (MWe)	52	
Avg. Breakdown of Energy Use by Fuel (TJ/day)		
Net Coal Consumption (2%)	0.693	
Natural Gas Consumption (27%)	9.340	
Electricity Consumption (13%)	4.500	
Coke Consumption (36%)	12.450	
Other* (22%)	7.610	
Water Consumption (gallons/tonnes)	13,000–23,000	
Avg. Water Flow (tonnes/day)	166,320.00	
Outputs		
Steel (Mt/day)	0.26	
CO_2 Emissions (kt/day)		
Ore-Pellet-Coke-Blast Furnace-Basic Oxygen Furnace	5.16E+02	

Ore-Pellet-Corex Furnace- Basic Oxygen Furnace	7.93E+02	
Ore-Pellet-Midrex-Electric Arc Furnace	4.81E+02	
Scrap-EAF	1.65E+02	

Paxton 2016; Elshennawy and Weheba 2015; Worrell et al. 2010.

Other* refers to net steam (sum of purchases, generation from renewables, and net transfers), and other energy that respondents indicated was used to produce heat and power (Worrell et al. 2010). Average refers to value per facility. Note: Mt refers to metric tonnes.

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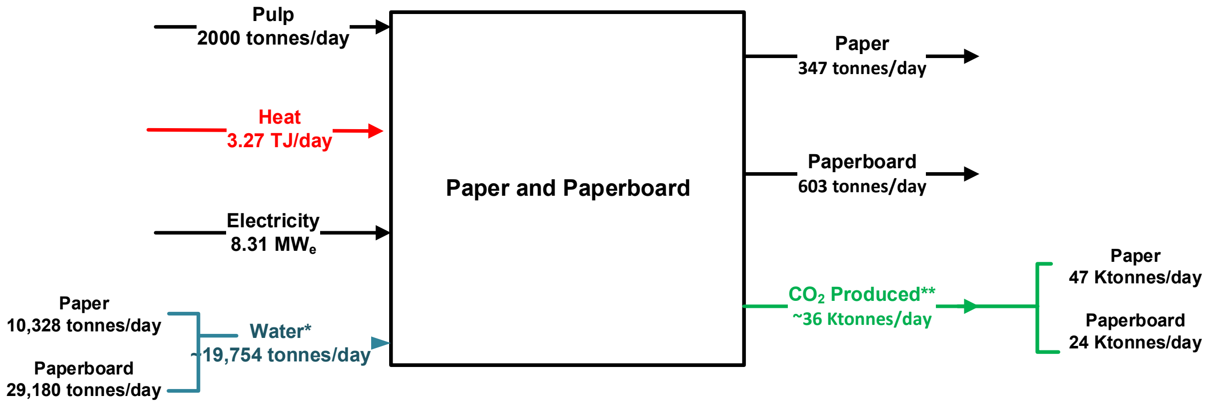
Appendix E. Paper and Paperboard Mills

The annual world production of paper and paperboard exceeds 330 million metric tonnes. In 2004, the United States produced 92 million metric tonnes, of which 42 million tonnes were classed as paper products and 50 million tonnes were products heavy enough to be classed as paperboard. Paper is mainly comprised of cellulosic fibers, mineral products, and bonding agents, including starch and latex products. Paper products normally weigh below 100–150 g/m^2 versus paperboard products, which are generally thicker and stiffer. Paper and paperboard mills primarily use wood pulp as the main raw material. The process for pulp production is addressed in Appendix F.

The pulp and paper industry relies on a diverse fuel mix that encompasses fossil fuels, as well as wood waste and byproducts. A large portion (~75%) is used for the production of steam and power in onsite systems (Miller et al. 2005). Excess power (if available) is fed back to the grid. Paper mills mainly use biomass/power boilers for production of steam and power for onsite systems.

Paper manufacturing takes homogeneous pulp slurry as an input feedstock, which is formed into sheets for pressing and drying. The largest use of fuels is to generate boiler steam.[2] The U.S. pulp and paper industry is the largest self-generator of electricity in the U.S. manufacturing sector (DOE-EIA 2007). A combination of high steam and onsite electricity (combined heat and power) is an ideal and attractive option for many mills around the country. The material and energy flows for a nominal paper and paperboard plant is shown in Figure E-1 based on the number of facilities and total production of paper and paperboard in the United States in 2002.



* USGS (1955)
*** DOE-EIA (2000), modified for 2002 census data

Figure E-1. Material and energy flows for a nominal paper and paperboard plant

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[2] Note: Currently, the Halden Reactor (a boiling water research reactor [25 MWt]) provides steam at 200°C at 0.6 MPa to the paper mill, and condensate/cold water is returned back to the reactor (Wiesenack 2016).

Process Flow Diagram and Description

Paper mills convert fibrous pulp (input feedstock) into paper and paperboard. Papermaking can be divided into three main stages (Kramer et al. 2009): (1) stock preparation, (2) wet-end processing (where sheet formation occurs), and (3) dry-end processing (where sheets are dried and finished).

Stock Preparation: The first step is bleaching the pulp to remove the lignin content in the slurry to increase brightness. Unbleached pulp is used for paperboard production (such as corrugated boxes). As shown in Figure E-2, the stock preparation involves: mechanical homogenization of pulp, dispersion in water, fiber declustering, additives addition, and blending and contaminant screening. Additives provide the specific desirable properties needed in the final product.

Wet-End Processing: The slurry from the stock preparation process is then fed into the wet-end papermaking process, where a paper web (i.e., sheets) is formed, transforming the volume of the diluted pulp into a fine, wide, and uniform laminate. Additional water is removed to increase fiber bonding. The pulp is then moved to the press section, where the remaining moisture content is squeezed from the paper.

Dry-End Processing: The bonded and dewatered sheet is fed into the dry-end papermaking process and goes through drying, calendaring, and reeling. For drying, steam-heated rollers compress and further dry the sheet through evaporation, which helps in additional bonding of fibers. Part way through the cycle, the cylinder is a size press, which is commonly used in the paper industry to apply the required coating. The process continues with cylinders/steam rollers to dry the applied coating. The calendaring process (pressing the sheet with a roll) controls the thickness and smoothness of the paper using polished iron rollers, and finished paper is wound on a large reel for storage and transportation.

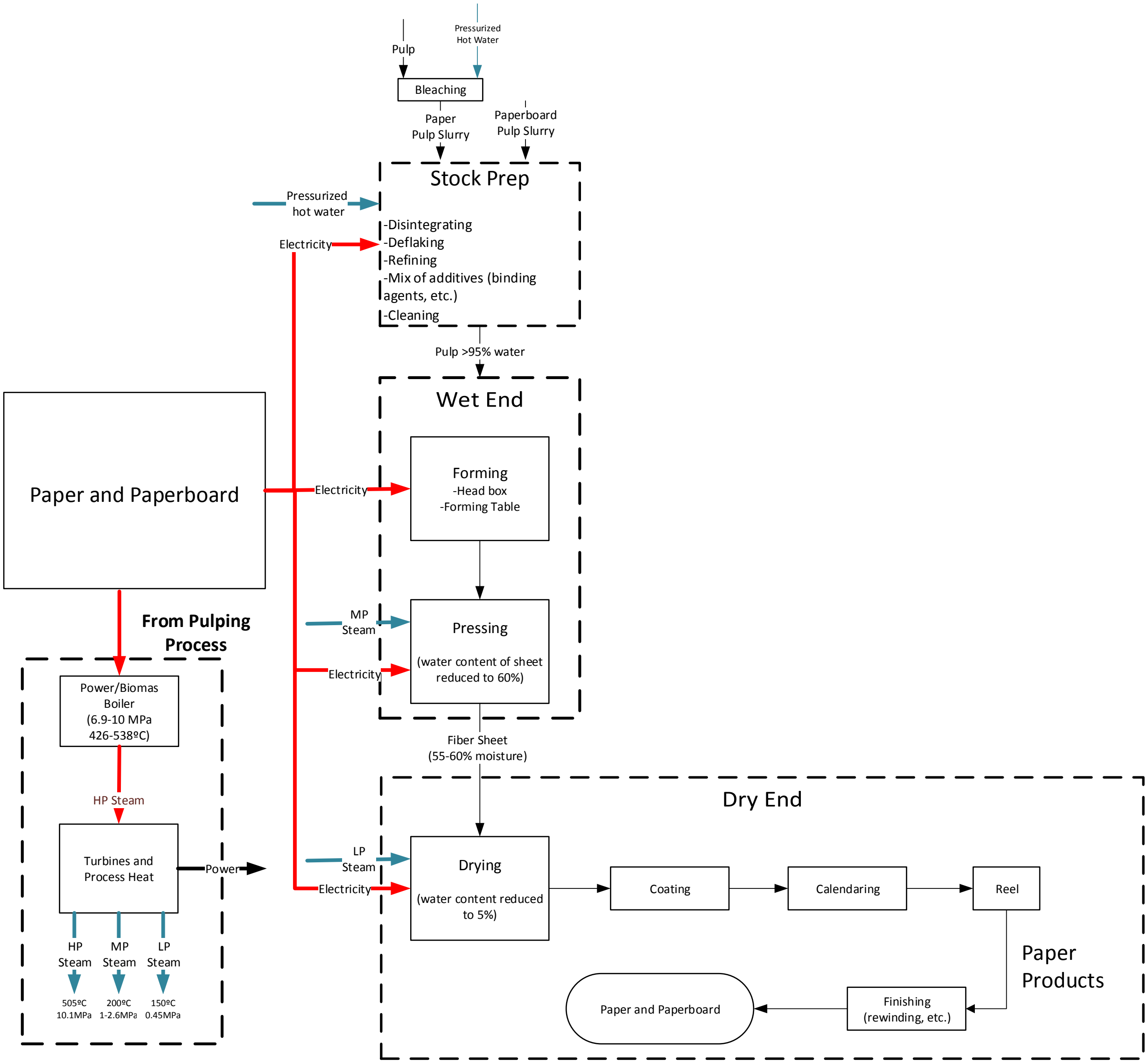

Figure E-2. Paper and paperboard manufacturing process

Energy Consumption

Paper manufacturing in the United States is a mature, energy-intensive industry. The U.S. pulp and paper industry is the largest self-generator of electricity in the U.S. manufacturing sector (DOE-EIA 2007). The combination of high steam demand and onsite electricity demand makes combined heat and power an ideal and attractive option for many mills around the country. Overall, refining, screening, forming, pressing, and finishing operations rely mainly on electricity, whereas drying operations require large amounts of steam. Figure E-3 shows that drying is the most energy intensive step associated with paper manufacturing processes. Figure E-4 shows that natural gas, purchased electricity, and coal are the major energy-related greenhouse gas (GHG) emission sources for U.S. paper mills. The estimates in Figure E-4 do not include GHG emissions arising from non-energy-related sources (such as lime kiln chemical reactions and methane emissions from mill wastewater treatment). Table E-1 and Table E-2 summarize the details on energy consumption and heat usage for the paper and paperboard manufacturing in the United States.

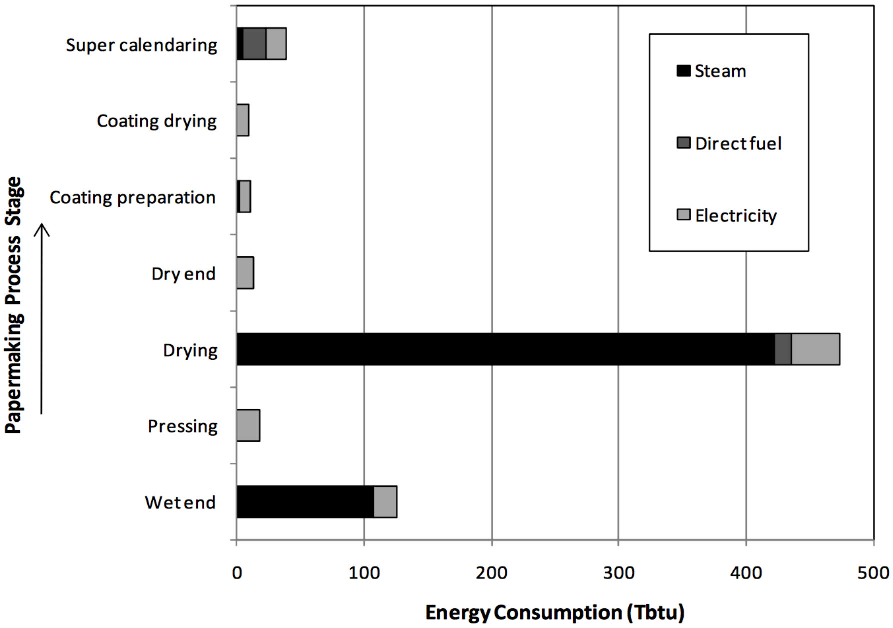

Figure E-3 Energy use of U.S. paper manufacturing by end use energy type in 2002 (DOE-EIA 2007; Jacobs and IPST 2006)

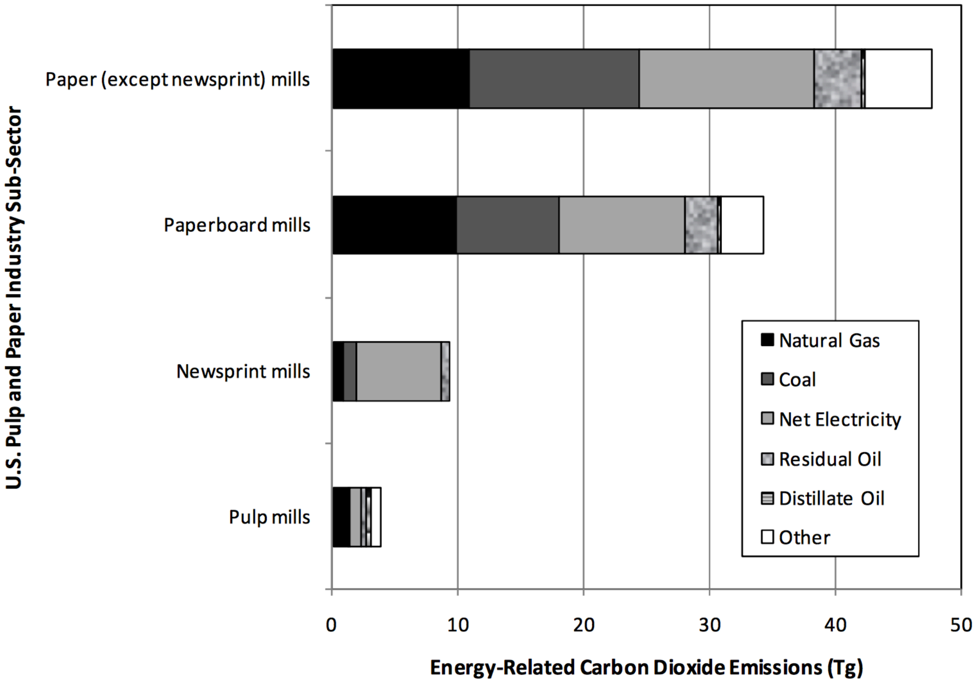

Figure 0-1. Estimated energy-related GHG emissions of the U.S. paper industry in 2002 (DOE-EIA 2007)

Table E-1. Production Comparison for Paper and Paperboard for 2002* and 2006 in the United States

	Production Based on 2002		Production Based on 2006	
	Facilities	**Production (tonnes/day)**	**Facilities**	**Production (tonnes/day)**
Paper	307	1.07E+05	325	1.04E+05
Paperboard	200	1.21E+05	205	1.25E+05
Total	507	2.31E+05	530	2.33E+05

*Production averaged between 2000 and 2003 values (U.S. Census Bureau 2011).

Table E-2. Energy Consumption of the U.S. Paper Industry (Based on 2002 Data, Kramer et al. 2009)

	Facilities	**Production (tonnes/yr)**	**Production (tonnes/day)**
Paper	307	3.89E+07	1.07E+05
Paperboard	200	4.40E+07	1.21E+05
Total	507	8.43E+07	2.31E+05
Energy Consumption by Process			
Wet End (Including Stock Prep)			
Steam (TJ/day)	315.07		
Electricity (MW)	602		
Pressing			
Electricity (MW)	669		
Dry End			
Electricity (MW)	502		
Drying			
Steam (TJ/day)	1,228		
Fuel (TJ/day)	31.79		
Electricity (MW)	1,304		
Coating Prep			
Steam (TJ/day)	8.67		
Electricity (MW)	301.02		
Coating Drying			
Electricity (MW)	334.47		
Super Calendaring			
Steam (TJ/day)	17.34		
Fuel (TJ/day)	54.92		
Electricity (MW)	501.71		
Total Electricity Requirement (MW)	**4,214.20**		
Average Electricity Requirement (MW)	**8.31**		
Total Heat Requirement (TJ/day)	**1,655.79**		
Average Heat Requirement (TJ/day)	**3.27**		
Water Consumption[a]			
Avg. Consumption for Paper (tonnes/day)	10,328.51		
Avg. Consumption for Paperboard	29,180.77		

(tonnes/day)			
Emissions[b]			
CO_2 Emissions (tonnes/day)			
Paper	47,123.29		
Paperboard	24,657.53		

[a] USGS (1955)

[b] DOE-EIA (2000), modified for 2002 census data.

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Appendix F. Pulp Process

The pulp and paper industry consumes a total of 73 GW_t each year. Pulping is the process of separating cellulose fibers from the other constituents of plant matter (predominately wood or recycled paper). The production of pulp occurs via chemical, semi-chemical, or mechanical processes. Most pulp in the United States is produced chemically using the sulfate ("kraft") process (DOE 2015). Black liquor, a by-product of kraft pulping, accounts for 36% of the total energy consumed. There are 114 mills that consume black liquor in the United States. The majority are in the southeast region of the United States (Lasley 2015). This summary is based on a reference pulp mill that uses the kraft process (AF-Engineering AB 2011). Details of the mill are found in Figure F-1. A summary of the process is shown in Figure F-2, with detailed information in Table F-1and Table F-2. Additional references on the kraft process are provided (Eggeman 2010).

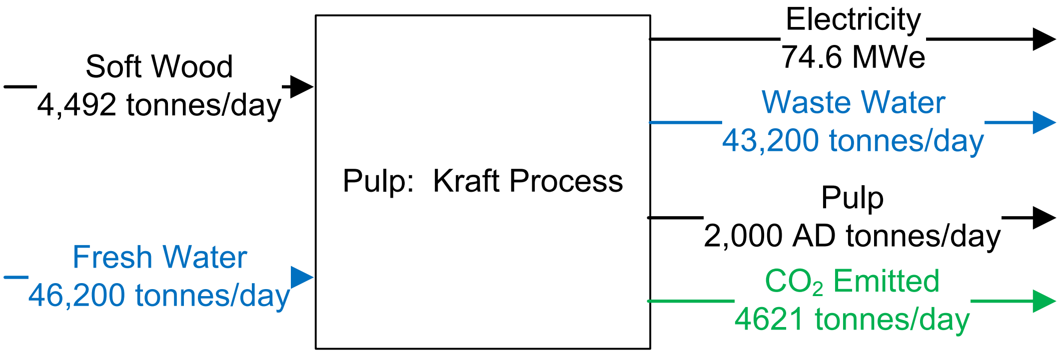

Figure F-1. Summary of pulp process

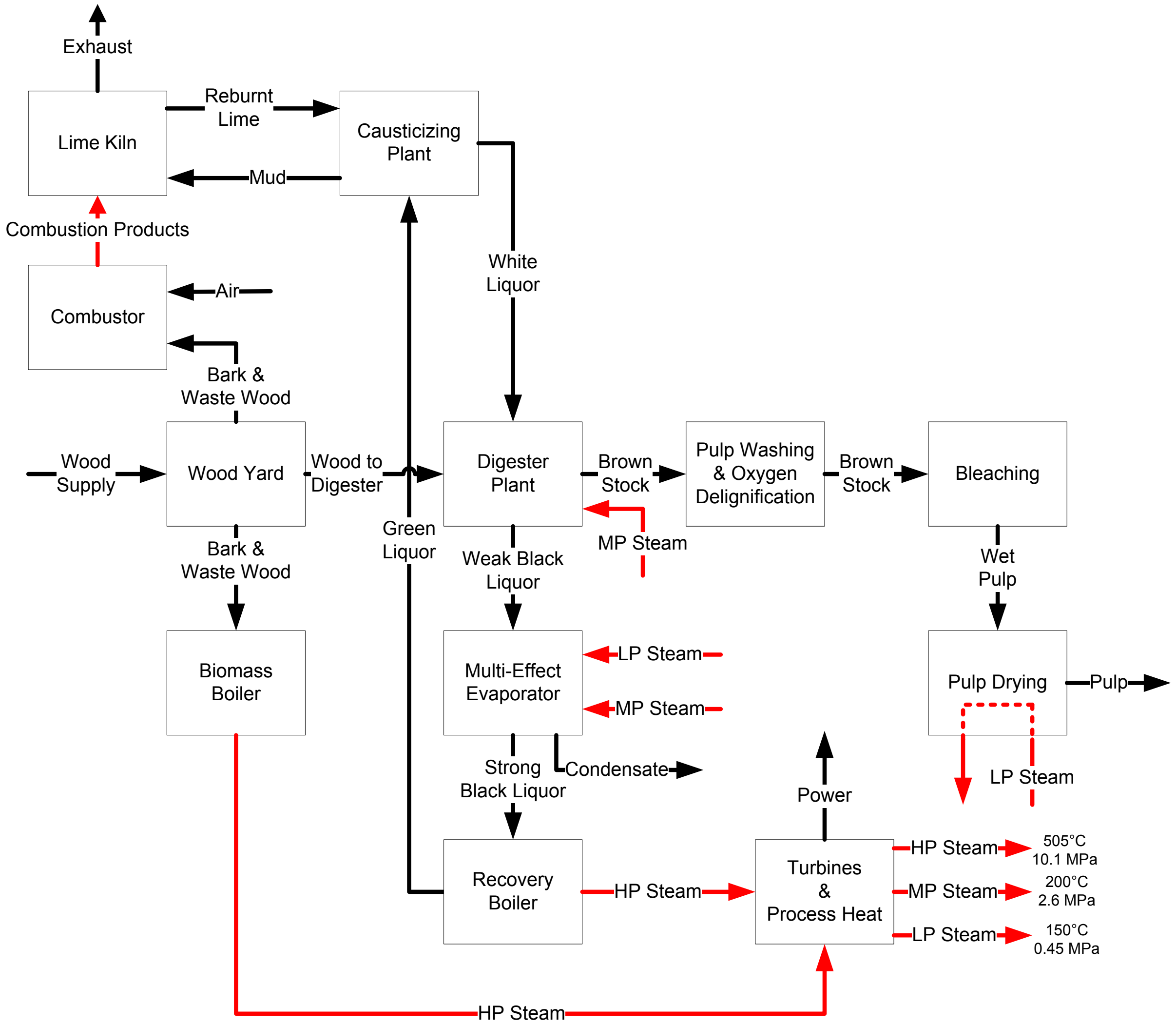

Figure F-2. Schematic of pulp-making Kraft process

Description

- **Wood Yard:** The raw wood is debarked in drums. After debarking, the logs are cut into chips in a chipper. The bark and waste wood are combusted and used for heat within the lime kiln and the biomass boiler.
- **Digester Plant:** The wood chips are pre-steamed, soaked, and cooked at 143°C with cooking chemicals composed of white liquor (sodium hydroxide and sodium sulfide), some black liquor, and medium-pressure steam from the recovery boiler. Black liquor that consists of spent pulping chemicals from the white liquor, dissolved wood, and water is formed. A brown stock is formed, which is the primary source of the pulp. Black liquor is removed in a single stage flash tank and sent to the evaporator. The brown stock is washed and bleached.
- **Pulp Washing and Oxygen Delignification:** Lignin is removed from the brown stock in two stages using oxidized white liquor as the primary alkali source. Two to three stages

of brown stock washing occurs depending on whether the wood source is hard or soft wood.

- **Bleaching:** Four bleaching stages are used to bleach the brown stock.
- **Pulp Drying:** The wet pulp passes through screen baskets to remove water and is then dried in a floating web of hot air heated by low-pressure steam from the recovery boiler.
- **Multi-Effect Evaporator:** A six- to seven-stage multi-effect evaporator is used to remove water from the weak black liquor. Low pressure and high pressure steam from the recovery boiler provides the heat for each stage.
- **Recovery and Biomass Boilers:** The black liquor is combusted to produce 412-MW_t high-pressure steam at 10 MPa and 505ºC within the recovery boiler. The steam is used to produce power and process heat. Bark and waste wood are combusted to produce 35 MW_t of 10 MPa, 505°C steam in the biomass boiler. The steam from this boiler is used to produce power. The molten smelt from the combusted black liquor contains mostly sodium sulfide and sodium carbonate. The smelt is dissolved in water to form green liquor, which is sent to the causticizing plant.
- **Turbines and Process Heat:** Power is produced by expanding high-pressure steam. Intermediate-pressure steam and medium-pressure steam are extracted from within the turbine. Low-pressure steam from the exit of the back-pressure turbine is also used as process heat. High-pressure steam not used for process heat is expanded through a condensing turbine to maximize power production.
- **Causticizing Plant:** Within the causticizing plant, the green liquor is filtered and the dregs are washed and sent to the landfill. The green liquor is reacted with lime to produce white liquor, which is sent to the digester plant. The precipitated calcium carbonate (lime mud) is sent to the lime kiln.
- **Lime Kiln:** Lime mud from the causticizing plant is heated to 800°C to produce lime (calcium oxide) for the causticizing plant. The heat is produced from combusting bark and waste wood.

Table F-1. Pulp Process Results

Inputs	
Wood to digester (tonnes/day)	4,072
Bark and wood waste	420
Outputs	
Pulp (air-dried tonnes/day)	2,000
Power (MWe)	74.6
Intermediate Streams	
White liquor (m^3/day)	7,541
Strong black liquor (tonnes/day), 80% dry solids	3,477
Utility Summary	
Total Power Sold (MW_e)	74.6
Wood yard	-3.8
Digester	-3.7
Washing and screening	-5.0
Oxygen stage	-5.0
Bleaching	-6.7
Final screening	-3.8
Pulp machine	-10.4
Evaporation	-2.3
Causticizing	-5.0
Boiler house	-6.7
Cooling tower	-2.1
Raw water treatment and distribution	-1.4
Effluent treatment	-1.4
Chemical preparation	-0.8
Miscellaneous, losses	-2.3
Total Power for Kraft Process	-60.4
Total Power Produced	135
Water (tonnes/day)	
Fresh water in	46,200
Wastewater	43,200
CO_2 Emissions	
Emitted (tonnes/day CO_2)	4,621

Table F-2. Heat Addition to Kraft Pulp Process

Heat Use in Pulp Process

	Heat (TJ/day)	Temperature In (°C)	Temperature Out (°C)
Heat from Combustion Products			
Heat to lime kiln	2.83	>800	
Heat from Steam			
High-pressure steam (10.1 MPa)			
Back-pressure turbine	6.24	505	150
Condensing turbine	16.04	505	35
Blowdown recover boiler	0.26	505	
Blowdown biomass boiler	0.02	505	
Medium-pressure 1 steam (2.6 MPa)			
Soot-blowing recovery boiler	2.05	275	
Soot-blowing power boiler	0.03	275	
Medium-pressure 2 steam (1 MPa)			
Digester	3.09	200	170
Bleaching	0.44	200	180
Oxygen stage	0.16	200	100
Multi-effect evaporator	0.84	200	140
Chemical preparation	0.05	200	100
Miscellaneous losses	0.29	200	100
Low-pressure steam (0.45 MPa)			
Pulp machine	4.15	150	100
Multi-effect evaporator	6.15	150	140
Chemical preparation	0.15	150	100
Miscellaneous losses	0.37	150	100

References

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Appendix G. All Other Basic Organic Chemical Manufacturing (Methanol Production)

As of 2013, North America's installed capacity for methanol production was 1.8 million tonnes/year. By 2020, this capacity is expected to increase to 6.5 million tonnes/year. With the decrease in the price of natural gas, methanol has become a popular means to make liquid fuels from natural gas. Methanol is used as a major octane booster but can also be blended directly with gasoline. It can also be used to make olefins as a replacement for naphtha (Morris 2013). The data used for this section are based on work done at Idaho National Laboratory (Wood 2010).

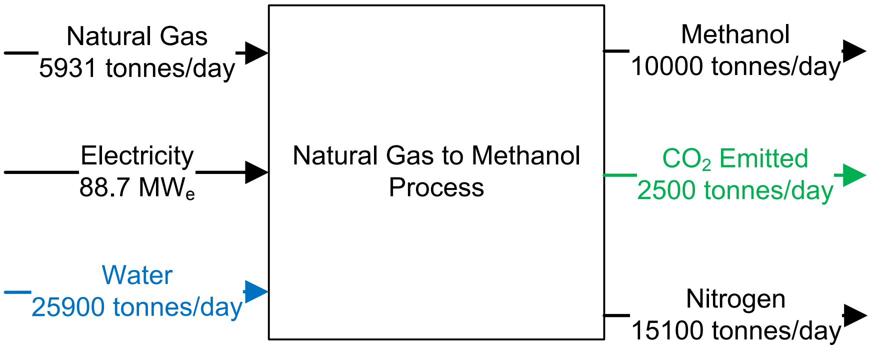

Figure G-1. Summary of natural gas to methanol

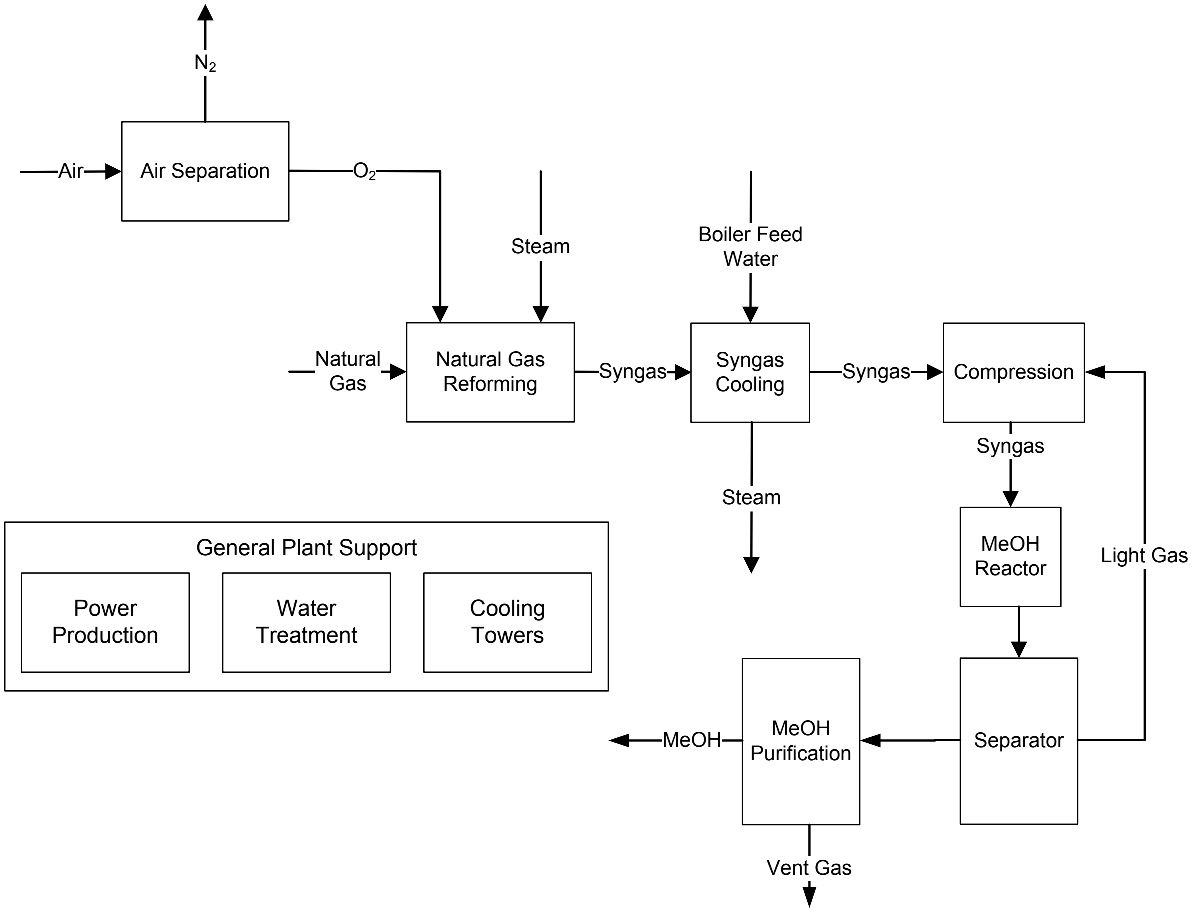

Figure G-2. Schematic of process for making methanol

Description

A schematic of the methanol process is shown in Figure G-2.

- **Natural Gas Reforming:** Two-step reforming was used for the data in Figure G-1 and Table G-1. The steam-to-carbon inlet molar ratio was set to 1.80, and the exit temperatures of the primary and secondary reformers were set to 739°C and 1,038°C. Natural gas is split into two streams. Of the total natural gas flow, 10.5% is burned to provide heat for the primary reformer. The remaining 89.5% of the natural gas flow is compressed to 4.24 MPa and then preheated to 177°C and saturated with hot water. After saturation, the gas is further heated to 350°C and mixed with a small amount of hydrogen. Sulfur is removed from the gas and then mixed with steam to achieve the desired steam-to-carbon molar ratio of 1.8. Because the resulting natural gas/steam mixture is preheated to only 538°C, a preformer is not included in this flowsheet. The natural gas/steam mixture is fed to the primary reformer where methane is converted over a catalyst to CO, H_2, and CO_2. Methane conversion in this reactor is approximately 25%. A separate feed of the natural gas is mixed with fuel gas and burned to provide heat for the endothermic reforming reactions. The hot offgas from the reformer is exchanged with inlet syngas, water, and steam to provide preheat for these streams. The effluent from the primary reformer and oxygen are fed to an autothermal reformer where conversion of the remaining methane to syngas is accomplished. The oxygen-to-carbon molar ratio is set at 0.41, which results in an exit temperature of 1,038°C. The hot syngas is cooled by exchange with boiler feed water to create steam, followed by condensation of the water from the syngas. The resulting syngas has an H_2/CO ratio of 3.1 and contains 7.2 mol% CO_2 and 0.9 mol% CH_4.

- **Air Separation:** Oxygen is produced through a standard cryogenic air separation unit, which utilizes two distillation columns and extensive heat exchange in a cold box. The oxygen product is used for gasification. The nitrogen co-product can be used for transport and as inert gas to be used throughout the plant. The waste stream from the air separation unit is an oxygen-enriched air stream.
- **Syngas Cooling:** The hot syngas makes steam within a boiler. The steam is used within the process.
- **Compression:** The syngas is compressed to 7.5 MPa prior to the methanol reactor.
- **Methanol Synthesis:** Syngas feeding the methanol synthesis unit has been previously adjusted to achieve a ($H_2 - CO_2$)/ ($CO + CO_2$) molar ratio of 2.10. This results in a H_2/CO molar ratio for the feed gas of 2.45. Incoming feed gas is compressed to 7.5 MPa, followed by heating via recuperation to 217ºC prior to introduction into the methanol conversion reactor. Methanol is formed via the following reactions:

  $$CO + H_2O \rightarrow H_2 + CO_2$$

  $$CO_2 + 3H_2 \rightarrow CH_3OH + H_2O.$$

  Which result in the net reaction for CO to methanol:

  $$CO + 2H_2 \rightarrow CH_3OH$$

  Methanol and unreacted syngas exiting the reactor are cooled by recuperation with the incoming feed gas, followed by condensation and separation of the liquid methanol product. Unreacted gas is recompressed, mixed with fresh incoming syngas, and fed back to the methanol synthesis reactor. A purge on the unreacted gas stream is set to limit buildup of inert gas within the synthesis loop; the molar recycle ratio is currently set at 4.0:1. These conditions result in a reactor inlet CO_2 concentration of 1 mol% and a methanol concentration in the reactor exit stream of 7.6 mol%. Condensed methanol product is purified in a distillation column to remove light gases prior to storage in the methanol intermediate product tank. The purge gases are used as fuel gas for power production in the plant.

Table G-1 and Table G-2 list relevant information about the methanol feedstocks, products, emissions, and heat and power usage.

Table G-1. Inputs, Products, Utility, and Emissions of Natural Gas to Methanol Process

Natural Gas to Methanol Process	
Inputs	
Natural Gas Feed Rate (tonnes/day)	5,931
Products	
Methanol (tonnes/day)	1,000
Nitrogen (tonnes/day)	15,100
Utility Summary	
Total Power (MW)	-88.7
Natural Gas Reforming	-13.8
Air Separation	-75.1
Power Island	59.8
Methanol Plant	-49.1
Cooling Towers	-2.77
Water Treatment	-7.69
Total Water Balance (tonnes/day)	-25,900
CO_2 Emissions	
Emitted (tonnes/day CO_2)	2,500

Table G-2. Heat Addition from Natural Gas

Location	**Heat Duty (TJ/day)**	**Inlet Temperature (ºC)**	**Outlet Temperature (ºC)**
Primary reformer	30.259	538	739
Preheat steam/air into secondary reformer	6.989	859	583
Preheat steam/natural gas into primary reformer	3.469	583	439
Preheat steam before mix with natural gas	3.798	439	276
Preheat natural gas before mix with steam	1.266	276	219
Natural gas preheat	0.253	219	208
Steam preheat	0.279	208	196
Process preheat	1.291	196	138

References

Morris, Gregory D.L. 2013. *The American Oil & Gas Reporter: U.S. Methanol on the Comeback.* April. Accessed September 12, 2016. http://www.aogr.com/web-exclusives/exclusive-story/u.s.-methanol-on-the-comeback.

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Appendix H. Ethyl Alcohol Production within Biorefinery

In 2015, nearly 50 billion liters of distilled alcohol were produced within the United States for beverage consumption, and 56 billion liters of ethanol fuel was produced (U.S. Department of the Treasury: Alcohol and Tobacco Tax Trade Bureau 2016; U.S. Energy Information Administration 2016). Ethanol may be produced through the fermentation of biomass or either direct or indirect hydration of ethylene (Eggeman 2010). Both the beverage industry and the current fuel ethanol industry use fermentation processes that convert edible grains to ethyl alcohol.

An alternative is to produce ethanol from inedible lignocellulosic biomass such as wood, wood waste, agricultural residues, and grasses. The National Renewable Energy Laboratory developed an ethyl alcohol production process and subsequent model. That model was used to estimate the heat usage and GHG emissions for a fermentation process (Humbird et al. 2011). Figure H-1 indicates the overall material and energy flows for the process. The heat input is almost exclusively generated from biogas and non-usable solids from the biomass feedstock. In this study, 20% by weight moisture content was assumed as part of the feedstock composition. Figure H-1 is a schematic of the process. A a description of each sub process is provided below.

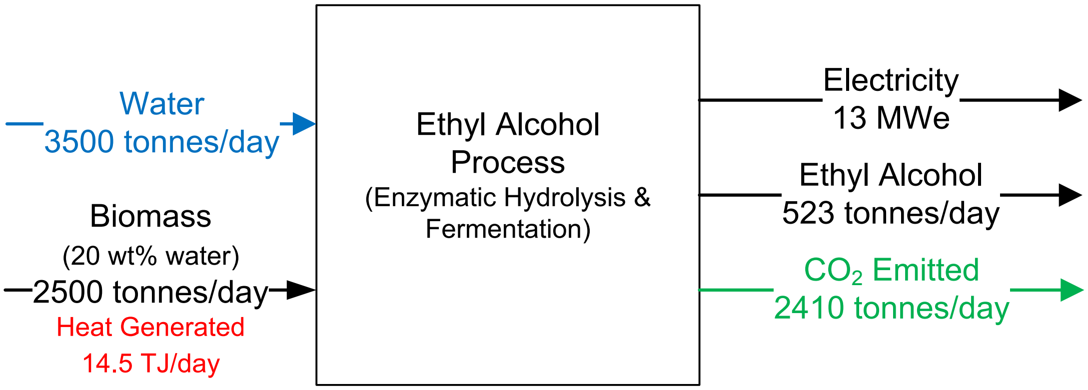

Figure H-1. Summary of ethyl alcohol process

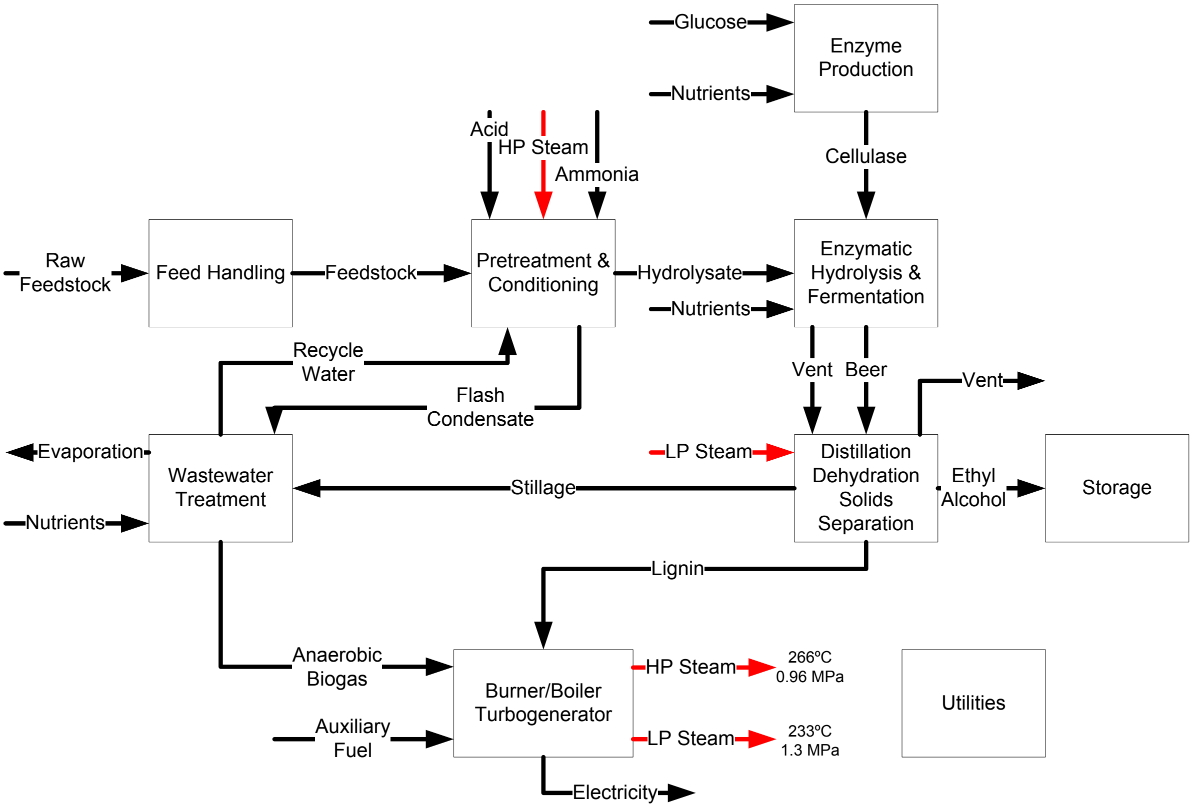

Figure H-2. Schematic of ethanol biorefinery process

Description

- **Feed Handling:** The raw feedstock is stored at a central depot where it is preprocessed and homogenized. The biorefinery receives a feedstock with known uniform-format specifications such as bulk density, size distribution, and moisture content.
- **Pretreatment and Conditioning:** Using hydrolysis reactions, the hemicellulose carbohydrates within the feedstock are converted to soluble sugars. The hydrolysis reactions are catalyzed using dilute sulfuric acid and heat from steam. After the pretreatment, the hydrolysate slurry is flash cooled, vaporizing large amounts of water and some acetic acid and furfural. The vapor is condensed and the condensate is sent to the wastewater treatment plant. Ammonia is added to the hydrolysate slurry to raise its pH from 1 to 5–6 for the enzymatic hydrolysis process. Pretreatment reactor temperature and pressure are 158°C and 0.56 MPa. The residence time in the reactor is 5 minutes.
- **Enzymatic Hydrolysis and Fermentation:** During this process the cellulose is converted to glucose using cellulose enzymes. A mixture of enzymes breaks down the cellulose fibers into glucose monomers. During pretreatment, the glucose and other sugars are fermented to ethanol. Enzymatic hydrolysis occurs while the slurry is at the higher temperature and pressure of the pretreatment process. Once the conversion of cellulose to glucose is completed, the slurry is cooled to fermentation temperatures and combined with a fermenting microorganism called the ethanologen. The viscosity of the slurry drops and is pumped to several parallel bioreactors. Hydrolysis continues within

these vessels until complete, after which the slurry is cooled and the ethanologen is added. The fermented broth is emptied into a storage tank before being sent to the distillation process. The enzymatic hydrolysis process runs at 48ºC and has a residence time of 3.5 days. The fermentation process runs at 32ºC and has a residence time of 1.5 days.

- **Cellulase Enzyme Production:** Cellulase is a mixture of enzymes (catalytic proteins) that includes endoglucanases, which attack cellulose fiber; exoglucanases, which break down the ends of highly crystalline cellulose fibers; and β-glucosidase, which hydrolyzes small cellulose fragments to glucose. The cellulase is produced onsite with ethanol using a slipstream of the hydrolysate slurry from pretreatment.
- **Distillation, Dehydration, and Solids Separation:** Distillation and molecular sieve adsorption are used to recover the ethanol from the fermented broth (beer) to produce 99.5% ethanol. Two columns are used: the beer column removes the dissolved CO_2, and most of the water and the rectification column concentrates the ethanol. The ethanol exits the rectification column to remove additional water using molecular sieve adsorption. During the regeneration of the adsorption columns, a low purity (70 wt%) ethanol stream is created and recycled to the rectification column for recovery. The overhead stream of the beer column and fermentation vents are fed to a water scrubber to recover almost all of the ethanol. The beer column bottoms are made of unconverted insoluble and dissolved solids. The water is removed from these solids, which are combusted. The water is sent to wastewater treatment. Low pressure heat (0.96 MPa steam) is supplied to the reboilers of the beer and rectifier columns.
- **Wastewater Treatment:** To reduce makeup water, the vapor flashed from pretreatment and boiler blowdown water, cooling tower blowdown water, and the pressed stillage water streams are mixed and processed by anaerobic and aerobic digestion to remove the organic materials within the wastewater. The resulting water is reused in the process, and the remaining sludge is burned in the combustor. Methane is also produced during the process, which is combusted. The process requires nitrification to handle the ammonia that will be produced. Reverse osmosis is used to remove the brine from the treated water. The brine is waste.
- **Combustor, Boiler, and Turbogenerator:** Various organic by-product streams are combusted to produce power and steam. These streams include the lignin, unconverted cellulose, and hemicellulose from the feedstock; biogas from anaerobic digestion; and biomass sludge from wastewater treatment. The boiler produces steam at 450ºC and 6.3 MPa. Process steam is extracted from the power turbines at 1.3 MPa and 268ºC for the pretreatment reactor and at 0.96 MPa and 164ºC for the distillation column. More power is generated than is needed for the process; therefore, the excess power is sold.
- **Utilities:** The utilities that are considered for this bioreactor include cooling water, chilled water, plant and instrument air, and process water. Cooling water is used to condense the steam turbine exhaust, condense the refrigerant within the chiller system, cool the pretreatment slurry, cool the ethanol product, cool slurry before fermentation, provide cooling for regeneration of the molecular sieve, condense beer column reflux, and condense flash vapors before wastewater treatment.

Table H-1. Inputs, Products, Utilities, and Emissions of Natural Gas to Ammonia Derivatives Processes

Ethyl Alcohol Production	
Inputs	
Biomass Feedstock (tonnes/day)	2,500
Outputs	
Ethyl Alcohol (tonnes/day)	523
Utility Summary	
Total Power Generated (MW)	41.3
Process power	28.5
Power sold to grid	12.8
Water Input (tonnes/day)	
Moisture in feedstock	500
Water in glucose	10
Water in raw chemicals	73
Generated in enzyme production	31
Generated in wastewater treatment	3
Generated in combustor	64
In air intake for enzyme production	573
Lignin cake dryer intake	15
Wastewater aeration intake	6
Combustor air intake	105
Makeup water	134
Water Output (tonnes/day)	
Water in ethanol product	3
Cooling tower evaporation	3,297
Stripped in enzyme aeration	19
Scrubber vent	13
Consumed in pretreatmet	59
Consumed in hydrolysis process	63
Wastewater evaporation	104
Wastewater brine	119
Combustor stack	1,307
Boiler blowdown	62
Heat (TJ/day)	
Steam heat generated in steam generator (454ºC & 6.07 MPa)	14.52
High-pressure steam heat (266ºC & 1.31 MPa) to pretreatment	1.73
Low-pressure steam heat (233ºC & 0.96 MPa) to fermentation	4.64

CO_2 emissions (tonnes/day)	
Fermenter emissions	57
Scrubber emissions	498
Wastewater treatment	92
Flue gas	1,762
Total	2,408

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Appendix I. Plastics Material and Resin Manufacturing (Polyethylene and Polyethylene Terephthalate)

The plastics and resin market continue to be the most dynamic of all manufacturing industries with swings in petroleum and natural gas supplies in the United States and worldwide. A definitive assessment of the output and trends of the chemical specialty market was not possible for this report; however, some approximate figures are nonetheless useful for evaluating the opportunity to utilize clean heat sources for these industries. Table I-1 breaks down the European plastics market in 2013–2014. Markets vary by country, depending on the end-use industries in each region.

Table I-2 European Plastics Demand by Polymer Demand[a]

Plastic/Resin	Abbreviation	End Product Examples	Recycle Number	Percent of Market Share in Europe (%)
Polyethylene terephthalate	PET	Beverage bottles, carpet fibers, textiles (polyester, Dacron™, etc.), packaging film	1	6.9
Polyethylene-high density	PE-HD	Milk bottles, automotive components, injection molding objects such as toys	2	12.1
Polyvinyl chloride	PVC	Vinyl, pipe, window frames and siding, boots, shower curtains, medical tubing	3	10.4
Polyethylene-low density **Polyethylene-linear low density**	PE-LD PE-LLD	Film for food packaging, reusable bags, cable wire encasement	4	17.5
Polypropylene	PP	Car components, yogurt containers, office supplies	5	18.9
Polystyrene **Polystyrene-expandable**	PS PS-E	Styrofoam™ used in egg cartons, hot beverage cups, packing "peanuts"	6	7.1
Polyurethane **Polycarbonate**	PUR PC	Insulation, sponge, plastic glass	7	7.4
Polytetrafluoroethylene **Acrylonitrile butadiene styrene** **Acrylonitrile styrene acrylate** **Polyamide**	PTFE ABS ASA PA	Cooking pan coating, paint additive, construction surfacing materials	NA	19.7

[a] Adapted from Association of Plastics Manufacturers (2015).

World plastics annual production rose from around 200 million tonnes in 2000 to 300 million tonnes by 2013 (Association of Plastic Manufacturers (PlasticsEurope) 2015). According to these same statistics, North America[3] and Europe's annual output of thermoplastics and polyurethanes averaged around 50 million tonnes, with about 10 million tonnes of polycarbonate, Teflon™, and other niche plastic products. However, the advent of low-cost natural gas is currently motivating a strong up-swing in U.S. plastics production.

Worldwide, PP, PE, and PVC production rank first, second, and third among the polymer industry. PET (or polyester) makes up about 18% of world polymer production and is the fourth-most-produced polymer (Ji June 2013). This is higher than the European percentage of the plastics market, but the ranking order is nearly consistent.

Increased production of U.S. ethylene and associated investment in new U.S. polyethylene capacity could increase U.S. polyethylene production to around 23 million tonnes per year by 2020, up from 17 million tonnes at the start of 2015 (Petrochemical Update 2015). This increase assumes 75% of the announced and specified polyethylene projects are built and commissioned by 2020. PET production in the United States in 2012 was steady at about 3 million tonnes (PET Resin Association (PETRA) 2015). This too is projected to increase with new plant capacities. For example, the Corpus Christi plant will add 100,000 metric tonnes per year and will reach an overall annual production of 1.1 million metric tonnes (Bailey 2016). PET that is first formulated into beverage bottles is commonly recycled. It carries the Society of Plastics recycle symbol "1" and can readily be converted into several usable products. In 2013, about 30% of PET products were recycled in the United States. In Europe, the PET recycle rate exceeds 50%.

PE and PET are representative chemical proxies for the plastics and resins manufacturing industry in the United States, comprising approximately one-third of the present market share of about 60 million tonnes. Ethylene is naturally the building block for PE. It is called out in this report as a proxy for all of the olefins that are supplied to these manufacturers (Appendix J).

Description

Polyethylene

The molecular structure of PE resin can be represented by the formula:

$$-(CH_2-CH_2)_x-Branch_1-(CH_2-CH_2)_y-Branch_2-(CH_2-CH_2)_z-Branch_3 -$$

Where the $-(CH_2-CH_2)-$ unit comes from ethylene, and x, y, and z values can be deliberately varied from 4 or 5 to very large numbers depending on process co-polymers and chain initiative catalyst and reactor retention times (Kissin 2015). In simplest form, low-density PE is produced at very high pressure, as shown in Figure I-1.

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[3] North America encompasses countries subscribed to the North American Free Trade Agreement (NAFTA).

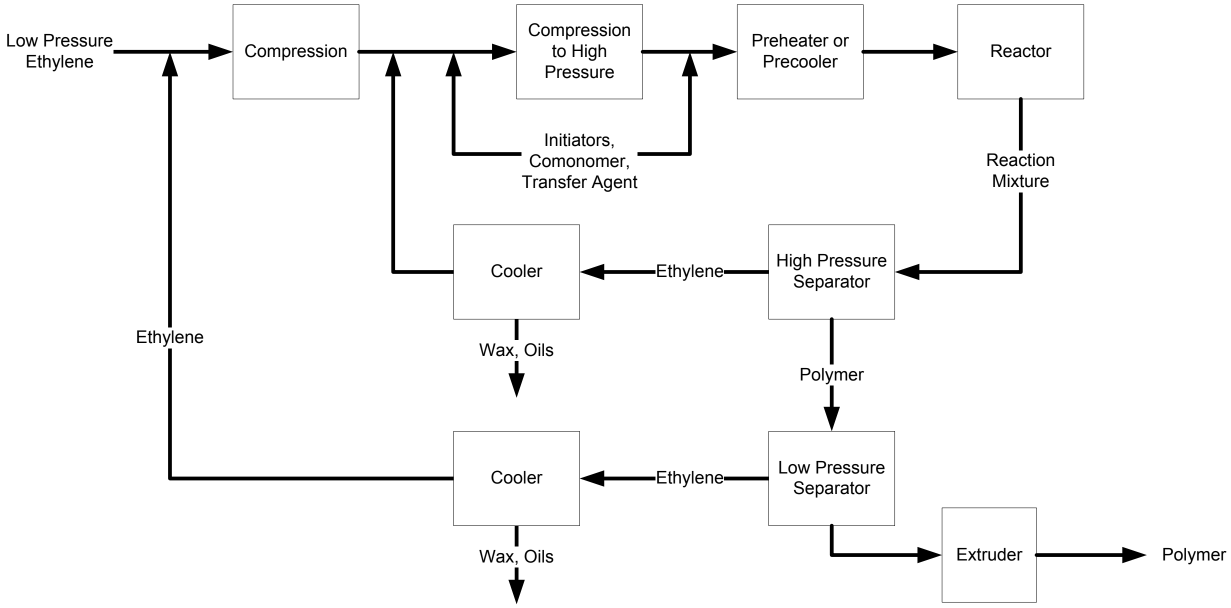


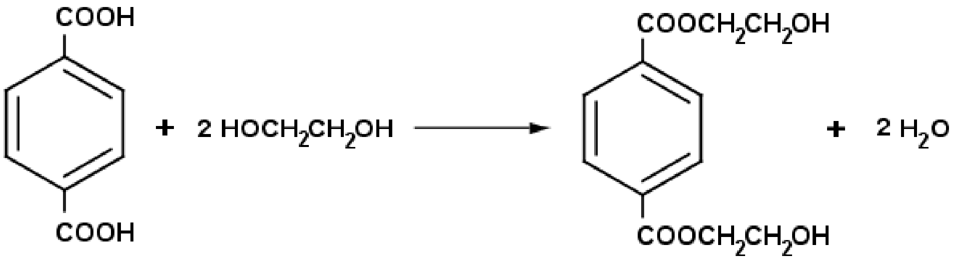
Figure I-1. General block flow diagram for low-density PE production

Compression to around 100–300 MPa (~14,500–44,000 psig) requires inter-stage cooling prior to polymerization (Maraschin 2005). Typical reactor temperatures range from 130–330°C. Polymerization is exothermic and gives off additional heat that is managed with coiling coils or by recirculating ethylene gas. This process heat could be used in co-located plants.

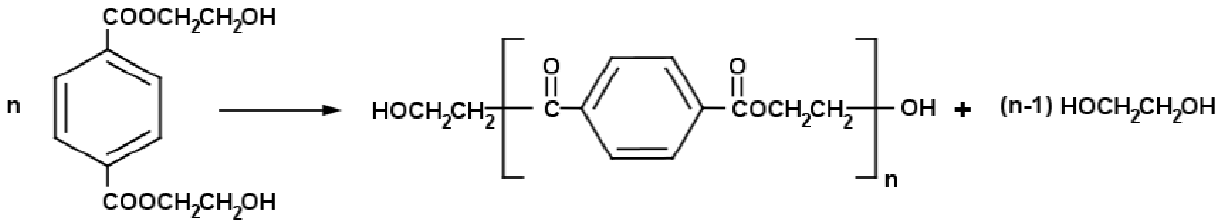
Polyethylene Terephthalate

Depending on its processing and thermal history, PET may exist both as an amorphous (transparent) and as a semi-crystalline polymer. Its monomer bis (2-hydroxyethyl) terephthalate can be synthesized by the esterification reaction between purified terephthalic acid (PTA) and ethylene glycol (EG) with water as a byproduct or by transesterification reaction between ethylene glycol and dimethyl terephthalate with methanol as a byproduct. Polymerization is through a polycondensation reaction of the monomers (done immediately after esterification/transesterification) with water as the byproduct. The former is the most common process; where PTA and EG react in sequence as follows:

Step 1 Reactor



Step 2 Reactor



In Step 1 reaction of PTA and EG (esterification) is carried out at around 260°C, near the melt-phase. Water is removed in a reflux column or by pervaporation. In step 2 reaction is completed at temperatures above the melting temperature of PET (260–265°C) and below the decomposition temperature of 300°C. A black-box material and energy balance based on figures extracted from Banat & El-Rub (April 2001) is shown in Figure I-2. A simplified process flowsheet is illustrated in Figure I.3. There are numerous processes, but generally each have the general two-step reaction path of esterification and polycondensation. A review and comparison of some commercial processes is provided by ResearchGate (2010). Polymerization releases 3,500 kJ/kg. Off-gas is vented and can be fired in a heat recovery/steam generation unit to provide steam to the distillation column.

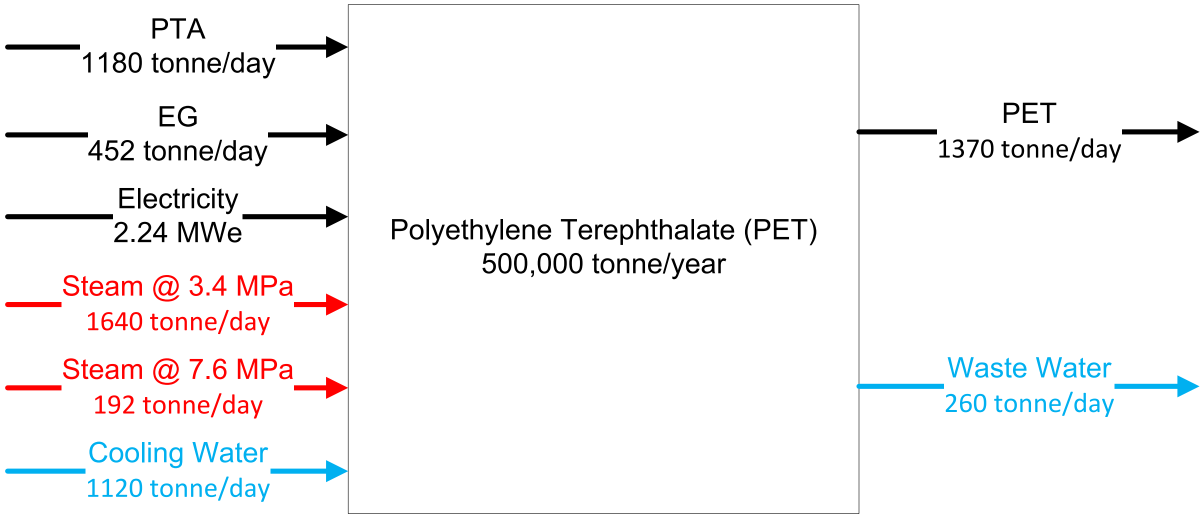


Figure I-2. Black-box energy and material balance for 500,000 tonnes/year PET plant

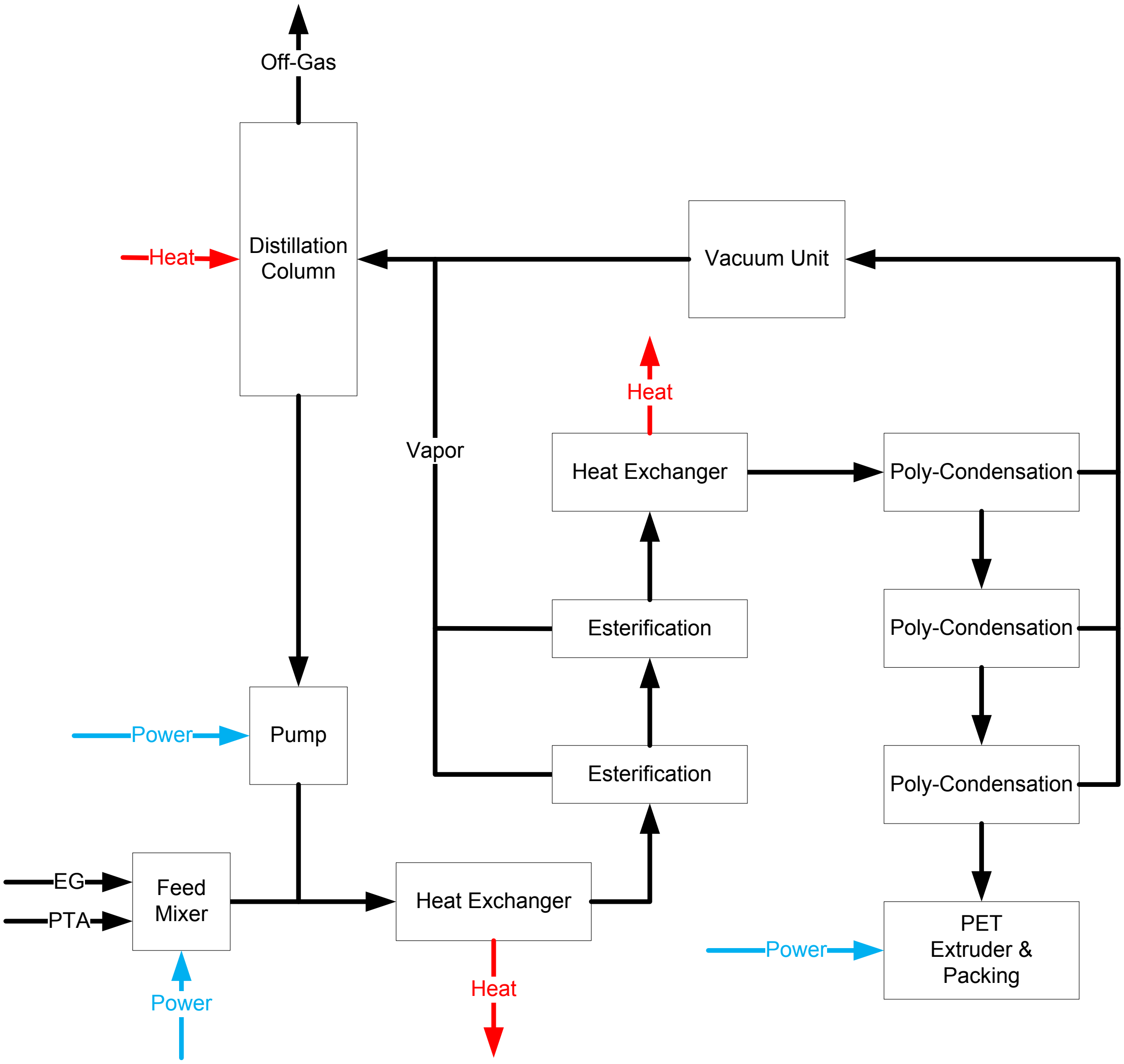


Figure I-3. Generic PET process flowsheet

Ethlylene glycol and purified terephthalate can be produced on location in an integrated plant. The former is produced by hydrolysis of ethylene oxide, produced from ethylene (evaluated in the next appendix); the latter can be produced from various routes but is mainly produced from para-xylene (*p-xylene)*. Technology profiles for each chemical are given in recent Technology Profiles in Chemical Engineering (Intratec Solutions 2015, 2016). Each of these processes requires significant steam input from an auxiliary; para-xylene requires hydrogenation.

Purified Terephthalic Acid

A comparison of commercial PTA plants is given by ResearchGate (2010) and Intratec Solutions (2016). A summary of the processes is tabulated here for purposes of projecting opportunities for clean heat use. Acetic acid and hydrogen make-up production energies are not included. The

Amoco and Eastman plants are the most common plant designs used. The average plant requirements are taken from the two plants listed.

Table I-2. Summary of Amoco and Eastman Chemical PTA Production Material and Energy Use

		Feeds (per ton PTA[a])						
Commercial Process	**Plant Size PTA (ton/year)**	**p-xylene (ton)**	**H_2 (Nm^3)**	**Acetic Acid (ton)**	**Temp. (°C)**	**Steam Duty (ton)**	**Electrical Duty (kWh)**	**Water (Nm^3)**
Amoco	350,000	0.68	6.24	0.06	175–225	2	700	220
Eastman	660,000	0.65	NA	0.36	204	0.355 HP	96	1,775
Approximate Average Plant	505,000	0.67	3.0	0.20	200	1	400	1,000

[a] PTA and TPA are considered equivalent for this analysis.

Ethylene Glycol

Monoethylene glycol (MEG) and ethylene glycol (EG) are produced in a relatively simple four-step process. (1) Ethylene and oxygen are fed to a catalytic reactor where ethylene oxide is formed. Steam is generated while cooling the reactor to maintain the reactor temperature. (2) Ethylene oxide is separated in an absorber unit, passing CO_2 from the oxidation stage and passed on to an ethylene carbonate formation reactor. (3) Ethylene oxide and CO_2 are reacted to form ethylene carbonate using a liquid phase homogeneous catalyst. (4) Ethylene carbonate is hydrolyzed to form MEG, also using a liquid-phase homogeneous catalyst. These process steps require overall net heat addition of approximately 14 GJ/tonne for production. Power requirements are minimal.

Overall Material and Energy Balance for PET Plant

This cursory material and energy flows for a fully integrated PET plant producing 500,000 tonnes per year (1,370 tonnes/day) is represented by the following black box. An LWR module of about 185 MW_t could provide the electrical and thermal loads for this complex. Given the current production of around 3 million tonnes per year, six such reactor modules would meet the energy needs of PET production in the United States. The 1.1 million-tonne plant in Corpus Christi would utilize 55 MWe and 231 MW_t heat.

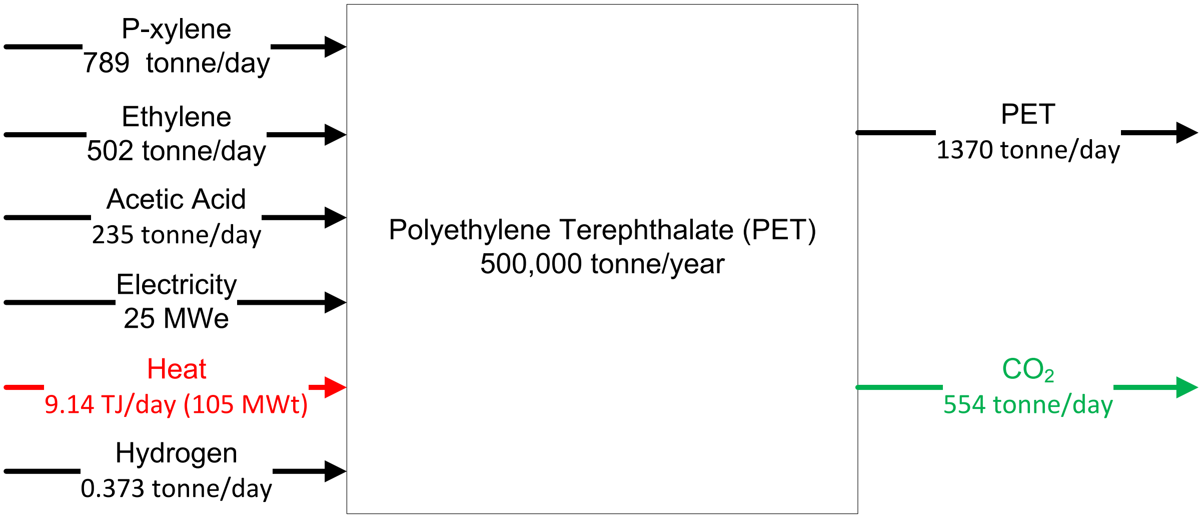


Figure I-4. Mass and energy input to PET process

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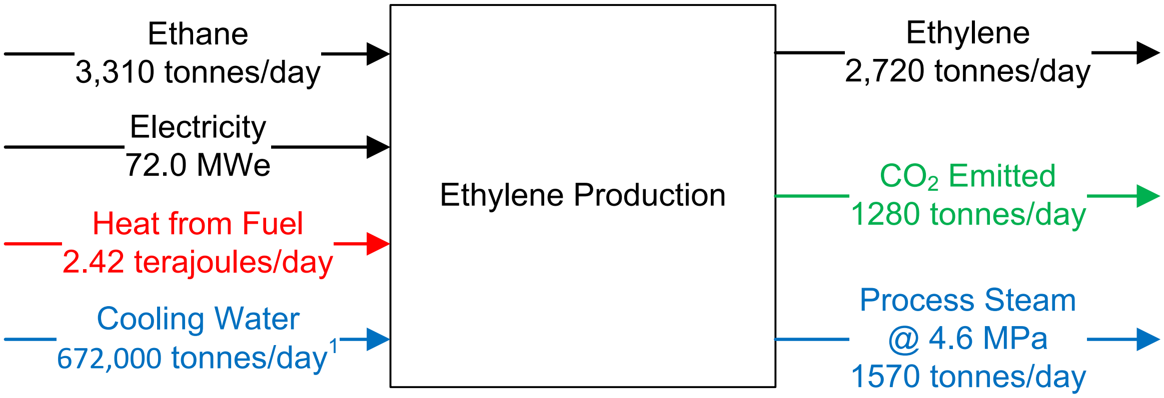
Appendix J. Petrochemical Manufacturing (Ethylene Production)

The U.S. production of ethylene is expected to be as high as 1.6 million barrels per day in 2018. Within the United States, 23 plants are in or will be in existence by 2018. Most of the plants lie along the gulf coast (U.S. Energy Information Administration 2015). The capacities of the plants range from 20,000 tonnes per year to 1.4 tonnes per year (Petrochemical Construction Map 2015). Polyethylene production consumes 60% of the ethylene produced. Ethylene oxide, which is used to make ethylene glycol, is the next largest user of ethylene. Ethylene is also used to make vinyl chloride, styrene, and chemicals used in detergent alcohols, plasticizer alcohols, vinyl acetate monomer, and industrial ethanol (Eggeman 2010). FigureJ-1 and Table J-1 are summaries of estimated data for the production of ethylene using ethane as the feedstock. The size of the plant is nearly 1 million tonnes per year. The CO_2 emissions were estimated by combustion of the fuel-assuming methane and the difference in carbon between the ethane feedstock and the ethylene product (Zimmerman and Walzi 2012).



[1] Cooling water is total flow of water needed. Does not account for reduction of net water if cooling towers are used.

Figure J-1. Summary of the ethylene process

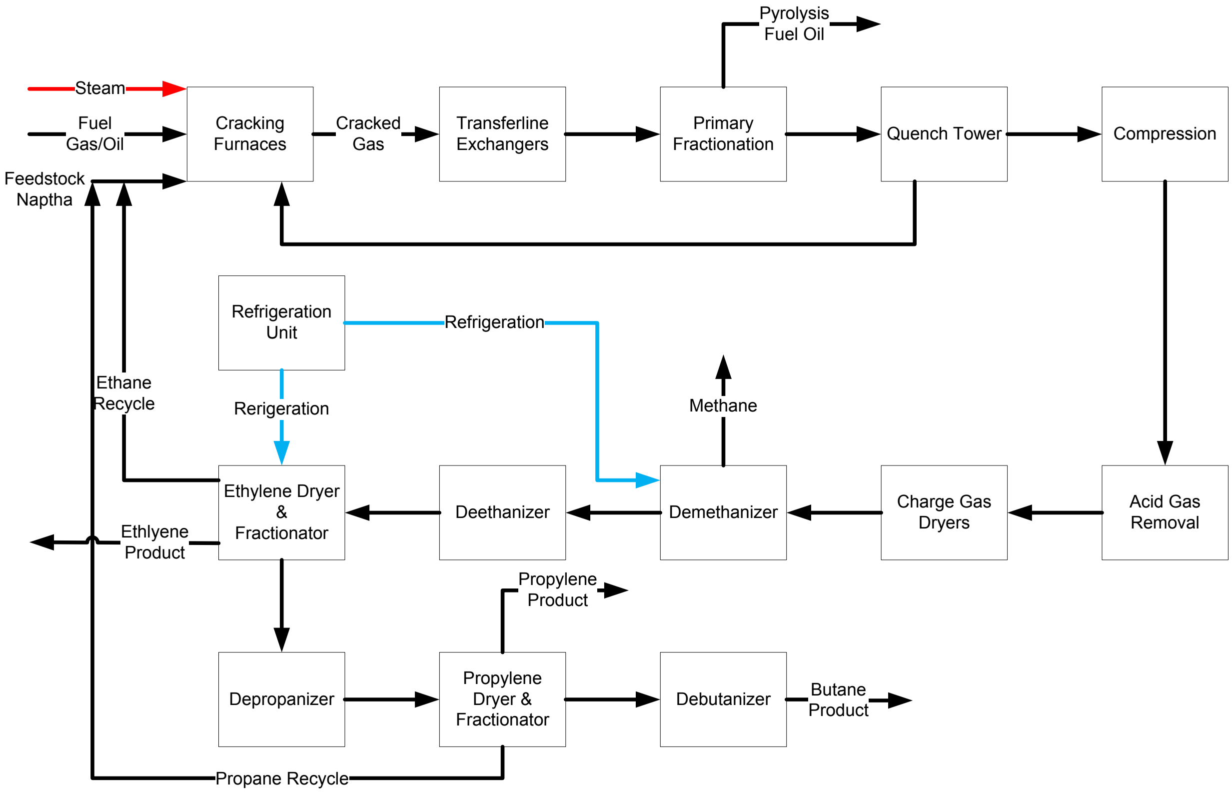


Figure J-2. Schematic of ethylene production process

Description

- **Cracking Furnace:** The thermal cracking furnace consists of a radiant section, a convection section, and the stack. The feedstock, typically naphtha or liquid petroleum gas and steam are pre-heated through heat recuperation with the flue gas in the convection section to incipient cracking temperature (500–680°C). The steam and feedstock are then heated in the radiant section of the furnace in tubes to 750–875°C within 0.1–0.5 seconds. The hydrocarbons in the feedstock are cracked into smaller molecules: olefins, such as ethylene, and di-olefins. The temperatures needed within the furnaces depend on the feedstock composition. Steam is added to minimize coke formation and increase the desired olefins. The products leave the radiant tubes at 800–850°C. The flue gas from the burners is also used to produce high pressure process steam within the convection section. Residence time, partial pressure, temperature, and temperature profiles affect the design of the cracking furnace.
- **Transfer Line Exchanger:** The cracked products from the furnace are cooled to 550–650°C within 0.02 to 0.1 seconds to prevent secondary reactions by using the transfer line exchanger. High-pressure process steam (6–12 MPa) is produced on the cold side of the transfer line exchanger. The transfer line exchanger is usually considered part of the cracking furnace.
- **Primary Fractionation:** The effluent enters the fractionator where the pyrolysis gasoline is separated from the pyrolysis fuel oil.

- **Quench Tower:** The quench tower condenses all the steam and most of the pyrolysis gasoline components. The water is separated from the condensed gasoline in quench water drums. The hot quench water is used as a process heat source for the recovery section.
- **Compression:** The compression of the cracked gas occurs over five stages to a pressure of 3.5 MPa.
- **Acid Gas Removal:** CO_2 and sulfur are removed after the third stage of compression using a caustic solution.
- **Charge Gas Dryers:** Molecular sieve dryers are used to completely remove the water.
- **Demethanizer:** The pyrolysis gas is partially condensed at constant pressure using the refrigeration system until hydrogen remains at a vapor state. The condensate first passes through the demethanizer, a distillation column, to produce methane off gas. The demethanizer operates at 0.7 MPa and separates the ethylene and heavier components from the methane.
- **Deethanizer:** The deethanizer is a tray-type fractionator operating at 2.4 MPa that separates the propylene and heavier components from hydrocarbons. The hydrocarbon overhead is heated to 100ºC and hydrogen added and passed over a palladium catalyst to produce acetylene, which also increases ethylene production.
- **Ethlyene Dryer and Fractionator:** This column uses a closed heat pump that supplies heat to the reboiler and cooling for the overhead condenser. Ethylene product is produced, and the ethane is sent back to the cracking furnace.
- **Depropanizer:** The condensate stripper bottoms and the deethanizer bottoms are processed in the depropanizer for the separation of lighter hydrocarbons from heavy hydrocarbons.
- **Propylene Dryer and Fractionator:** The overhead from the depropanizer is sent to the fractionator to separate the propylene from the propane. The fractionator operates at pressure of 1.8–2.0 MPa. The bottom product is mainly propane, which is sent back to the furnace for cracking.
- **Debutanizer:** The bottoms of the depropanizer are sent to the debutanizer for the separation of butane from light pyrolysis gasoline. The debutanizer operates at a pressure of 0.4–0.5 MPa. It is a standard fractionator using steam-heated reboilers and water-cooled condensers.

Table J-1. Ethylene Process

Inputs	
Ethane (tonnes/day)	3,310
Outputs	
Ethylene (tonnes/day)	2,720
Utility Summary	
Total Power (MW_e)	72.0
Compressors	72.0
Other electrical	0.0035
Water (tonnes/day)	
Cooling water (assuming no cooling towers)	672,000
CO_2 Emissions (tonnes/day)	
Conversion of Ethane to Ethylene	1,153
From Combustion of Fuel	123
Total	1,276
Heat	
Fired Duty of Cracking Furnace (terajoules/day	53.0
Fuel Gas Import (terajoules/day)	2.42
Super High-Pressure Steam (6.5 MPa) Generated and Used in Process (tonnes/day)	9,800
High-Pressure Steam (4.6 MPa) Exported (tonnes/day)	1,570

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Appendix K. Alkalies and Chlorine Manufacturing

The U.S. Census Bureau refers to the chlorine industry as the “chlor-alkali” (SIC 2812; NAICS 325181) industry (Mansfield et al. 2000). Chlorine and alkali production is heavily dependent on electricity. Production of chlorine occurs through the electrolysis of a salt solution, which results in the production of sodium hydroxide (caustic soda) and hydrogen gas.

$$2NaCl + 2\ H_2O \xrightarrow{\text{Electrical energy}} Cl_2 + H_2 + 2NaOH_{(aq)}$$

There are many processes available with varying energy requirements for chlor-alkali production, but the main processes use diaphragm cell, membrane cell, and mercury cell. Diaphragm cells are the most commonly utilized route for chlorine and alkali production in the industry; this process is further discussed.

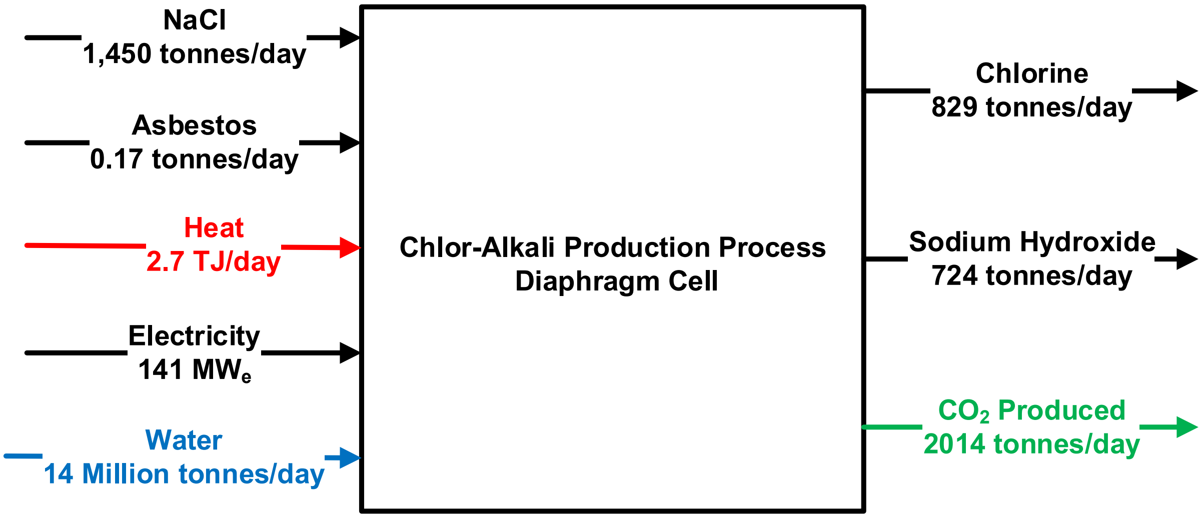

Figure K-1. Material and energy flows for a nominal chlorine-alkali plant

Process Flow

Electrolysis of the brine is the primary method used for chlorine production. Similarities exist across the cells used for electrolysis. The main distinguishing characteristic is the manner by which the electrolysis products are prevented from mixing (Mansfield et al. 2000). The process flow diagram is shown in detail in Figure K-1, and the main processes are described as follows:

- **Salt Mining:** Brine is produced from mining natural deposits or seawater (via solar evaporation).
- **Brine Purification, Filtration, and Heating:** Seawater sources contain impurities so the brine (mixture of salt NaCl and water) goes through purification and filtration process for removal of the impurities and the pH value is adjusted to 10.5–11. Further, brine is heated between 90°C and 105°C, which is the required temperature before being fed to the diaphragm cell.

- **Electrolysis (Diaphragm Cell):** Brine flows through the anode chamber into the diaphragm cell to the cathode. As the brine flows in the anode compartment of the cell, chloride ions are reduced forms of chlorine gas. The solution then passes through the diaphragm into the cathode chamber, where sodium hydroxide (also known as caustic soda) and hydrogen are produced. The cathode allows liquid to pass through, while avoiding fine chlorine gas bubbles to enter.
  - **Caustic Soda Evaporation, Concentration, and Flaking:** The diluted sodium hydroxide solution, which was passed through the diaphragm cell, contains residual salt that undergoes an evaporation process to produce sodium hydroxide in a usable concentration. The cell liquor is concentrated from the cell through water evaporation from the caustic, thus separating the residual salt from the sodium hydroxide. This results in 50% sodium hydroxide solution. Further processing can output 70%–74% sodium hydroxide or anhydrous sodium hydroxide, as shown in Figure K-2.
  - **Chlorine Compression and Liquefaction:** The diaphragm provides the much-required barrier between the cathode and anode to prevent reaction between NaOH and H_2 with chlorine and to avoid formation of oxygenated compounds of chlorine. Chlorine gas is collected at the top of the cell, cooled, compressed, and liquefied. Chlorine is cooled using Freon™ or a similar refrigerant and then washed with sulfuric acid in a packed column to dry it. Spent sulfuric acid is recovered and reused. After drying, chlorine is compressed to a higher pressure to allow liquefaction of the gas and then further collected.

By the nature of the chemical reaction, chlorine, sodium hydroxide, and hydrogen are manufactured in a fixed ratio (i.e., 1.1 tonnes of sodium hydroxide and 0.03 tonnes of hydrogen per tonne of chlorine). Chlorine is one of the most widely used chemicals, present as feedstock or as an intermediate in a large number of manufacturing processes of many chemicals, plastics (PVC), and medicine.

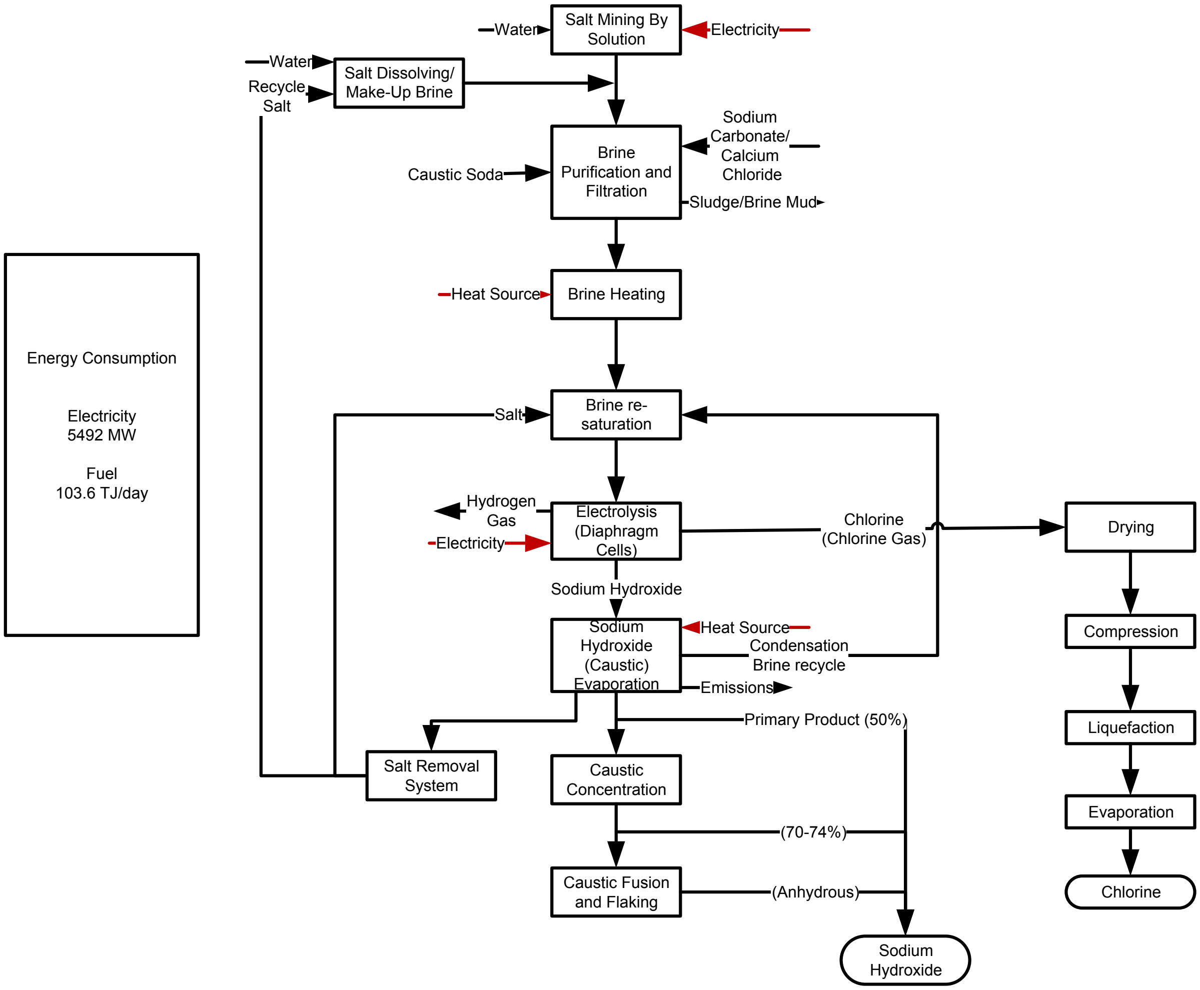

Figure K-2. Sodium hydroxide and chlorine production process flow diagram using electrolysis (diaphragm cell)

(DOE 2000; Bommaraju et al. 2002).

Table K-1. Chlorine and Alkali Process Summary for the United States

Chlor-Alkali Industry Process Results (based on 1997 U.S. Census Bureau data)		
Facilities		39
Inputs		
	Salt (NaCl) (tonnes/day)	56,544
	Asbestos (tonnes/day)	6.462
Outputs (Production)		
	Chlorine (tonnes/day)	32,311
	Alkali	
	Sodium Hydroxide (tonnes/day)	28,210
Utility Summary		
Electricity (MW)		
	Rectifier	98.3
	Cell Use	4,743.8
	NaOH Cooling	92.0
	Hydrogen Cooling/Drying	202.9
	Chlorine Cooling/Drying	136.4
	Chlorine Compression	218.8
Total Electricity (MW)		5,492
Avg. Electricity (MW)		141
Heat Source (TJ/day)		
	Brine Preparation	0.55
	NaOH Concentration	103.01
Total Heat Source (TJ/day)		103.6
Avg. Heat Source (TJ/day)		2.7
Fuel Distribution (TJ/day)		
	Oil (3%)	3.1
	Natural Gas (77%)	79.7
	Coal and Coke (10%)	10.4
	Other (10%)	10.4

	Total	103.6
Steam Quality		
	Steam Pressure (MPa)	Steam Temperature (^{o}C)
Brine Heating	0.82	177
Evaporator	0.82	177
Water (Mtonnes/day)		538
Emissions		
	CO_2 Emissions (tonnes/day)	78,527

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Appendix L. Nitrogenous Fertilizer Manufacturing (Ammonia Production)

In 2015, 9.4 million tonnes of ammonia were produced within the United States and an additional 4.5 million tonnes were imported. Fertilizer production accounted for 88% of U.S. ammonia use including urea, ammonium nitrates, ammonium phosphates, nitric acid, and ammonium sulfate. Non-fertilizer uses of ammonia are plastic production, explosives, synthetic fibers and resins, and other chemical compounds. A total of 29 U.S. plants in 15 states produced the ammonia. During this time, the plants operated at 80% of their rated capacity (Apodaca 2016). Plant capacity size within the United States ranged from 10,000 tonnes/year to 1.7 million tonnes/year. Ammonia is produced using the Haber-Bosch process in which hydrogen is reacted with nitrogen. Air is the primary source for the nitrogen and steam-reforming of natural gas is the most common source of the hydrogen (Eggeman 2010). The feeds and the products from a process flow model of a conventional natural gas to ammonia plant with ammonia derivative products are shown in Figure L-1. Assuming 80% plant capacity, the plant produces 891,000 tonnes/year of ammonia (Wood 2010). Heat is produced in a furnace for the primary steam reformer using 23% of the natural gas; the remainder is used for feedstock within the reformer to produce the hydrogen needed for ammonia production and the CO_2 for urea production. The heat duty is based on the higher heating value of the natural gas combusted.

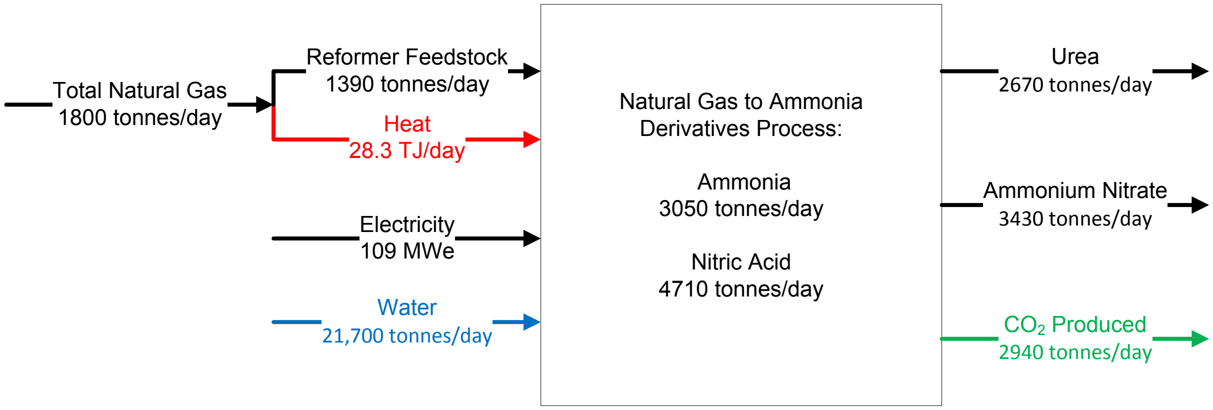

Figure L-1. Summary of material and energy flows for a nominal ammonia plant producing urea and ammonium nitrate

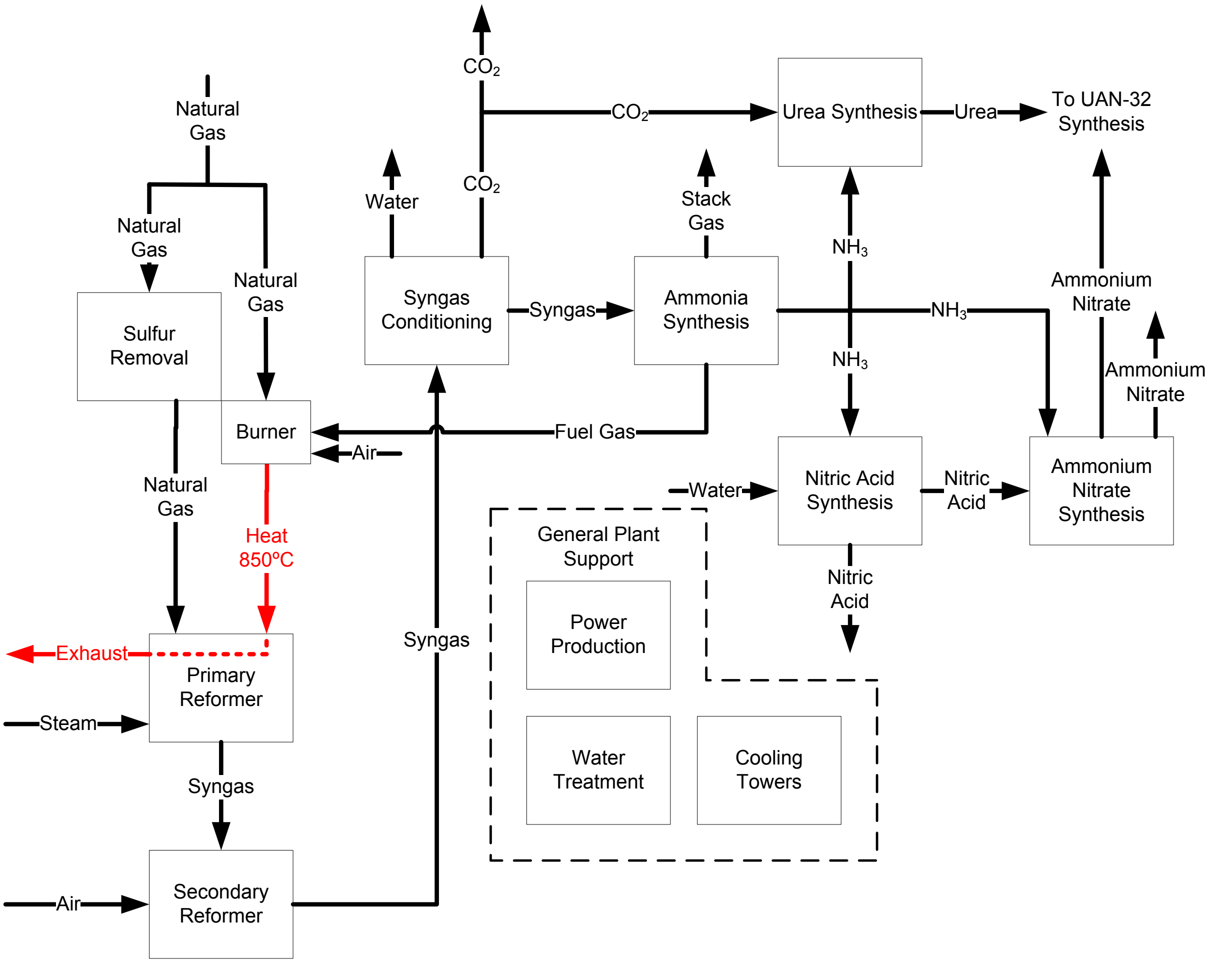

Figure L-2. Schematic of process for making ammonia and its derivatives

Description

A schematic of the ammonia process is shown in Figure L-2.

- **Natural Gas Purification and Reforming:** Synthetic gas (or syngas) for the ammonia process is produced using a two-step reforming process consisting of primary steam reforming followed by secondary auto-thermal reforming. Air is used to burn the natural gas within the auto-thermal reforming process, which leaves nitrogen as a by-product for ammonia production. By controlling the process parameters such as steam to carbon molar ratios, primary reformer temperature, and the amount of preheat to the secondary reformer as well as its temperature, the desired stoichiometry ratio of H_2/N_2 can be achieved for ammonia production. The primary reformer temperature is on the order of 800ºC, whereas the auto-thermal reformer has an outlet temperature near 950ºC. Combusted natural gas exhaust at 850ºC is used to heat air to 550ºC that is used in the auto-thermal reforming process. The natural gas exhaust at 725ºC is used to heat water and natural gas to 550ºC for the primary reformer. About 23% of the natural gas is burned to create heat, the remainder is a carbon source for the primary reformer. The syngas exiting the reforming process is 36% hydrogen, 8% CO, 5% CO_2, 15% N_2, and 35% water by molar content.

- **Syngas Conditioning:** The syngas is passed through a sour shift reactor to maximize hydrogen production through the water shift reaction. Excess water is condensed and sent to water treatment. An absorber with a solvent is used to remove the CO_2 and trace amounts of sulfur compounds.
- **Ammonia Production:** The conditioned syngas has a molar composition of 75% hydrogen and 25% nitrogen. Incoming feed gas is compressed to 13.8 MPa. Preheating of the gas is accomplished by mixing fresh syngas with hot recycle gas exiting the second ammonia synthesis reactor. Equilibrium conversion is assumed in the ammonia converters for the following reaction:

  $$N_2 + 3H_2 \rightarrow 2NH_3$$

  Effluent from the first ammonia converter is cooled by cross exchange with the reactor influent, followed by cooling in a steam generator. Additional steam is generated from the hot syngas downstream of the second and third ammonia conversion stages. Final cooling of the third stage effluent gas is accomplished using cooling water and recuperation with the cool recycle gas stream. Ammonia product is recovered in an ammonia separator. Effluent gas from this separator is further cooled using refrigeration. Additional ammonia is recovered in a second separator downstream of the refrigeration unit. Effluent gas from the second separator is recycled to the ammonia converters. Before entering the ammonia converters, the recycle gas is recompressed using a boost compressor and mixed with fresh syngas. Due to the very low concentrations of methane and argon entering the synthesis loop, inert gases pass out of the system absorbed with the ammonia product. Recovered ammonia is flashed to atmospheric pressure for storage. Ammonia in the flash gas is recovered in a wash column and subsequently distilled to remove water from the recovered product.
- **Nitric Acid Synthesis:** Ammonia is mixed with compressed air and reacted within an ammonia converter to produce nitrogen, NO, and water. The reaction is exothermic, producing temperatures approaching 925ºC. Heat is removed through recuperation and steam generation, and the cooled gas reacts with oxygen to produce NO_2, N_2O_2, and HNO_3. The aqueous nitric acid is separated from the product stream, and the remaining gases are sent to an absorber to increase the production of the acid. Unreacted gas is sent to a selective catalyst reduction unit to remove NO_x before atmospheric release.
- **Ammonium Nitrate Synthesis:** Ammonia and nitric acid are preheated and reacted in a neutralizer to form ammonium nitrate. Excess water is removed, and 95% of the remaining solution is recycled back to the neutralizer. The remaining solution is concentrated in a two-stage evaporator. The concentrated solution is solidified using a prill tower.
- **Urea Synthesis:** Ammonia and CO_2 are reacted at 2,000 psi to form ammonium carbamate, which dehydrates to form urea. The liquid product is fed to a CO_2 stripper and downstream decomposer where unreacted ammonium carbamate is decomposed to ammonia and CO_2 to allow easy separation of the urea. The recovered ammonia and CO_2 are cooled and condensed to reform ammonium carbamate, which is mixed with fresh

feed gases and sent back to the reactor. The urea is concentrated through evaporation and then solidified using a fluidized bed granulator.

- **Power Generation:** Some power is produced from within the plant from high-pressure (2.87 MPa) and low-pressure (0.515 MPa) steam generated throughout the plant. The power generation is not sufficient to meet the power needs of the process; therefore, power is purchased from the grid.

Table L-1 and Table L-2 list relevant information about the ammonia and ammonia-based feedstocks, products, emissions, and heat and power usage. To explain the external heat usage, a schematic of the reforming process is shown in Figure L-3. The exhaust gas from the burner supplies heat to each of the locations listed in Table L-2 and is represented by the grey shape in Figure L-3. The exhaust gas provides heat first to the primary reformer and then exchanges heat to preheat the water and natural gas feed streams as well as producing some process steam. Except for the primary reformer, the outlet temperature of the heat exchanger is the inlet temperature of the heat exchanger, as listed in Table L-2.

Table L-1. Inputs, Products, Utility, and Emissions of Natural Gas to Ammonia Derivatives Processes

	Natural Gas to Ammonia Derivatives Process
Inputs	
Natural Gas Feed Rate (tonnes/day)	1,804
Intermediate Outputs	
Ammonia (tonnes/day)	3,050
Nitric Acid (tonnes/day)	4,710
Output	
Urea (tonnes/day)	2,670
Ammonium Nitrate (tonnes/day)	3,430
Utility Summary	
Power Produced from Steam	28.9
Electrical Consumers	
Natural Gas Reforming	-21.6
Syngas Purification	-4.4
Power Block	-2.2
CO_2	-13.0
Ammonia Synthesis	-45.2
Nitric Acid Synthesis	-15.1
Ammonium Nitrate Synthesis	-24.9
Urea Synthesis	-4.4
Cooling Towers	-1.5
Water Treatment	-5.4
Sum of Power Consumption	-137.7
Net Plant Power	-108.8
Total Water Balance (tonnes/day)	-21,700
Evaporation Rate (tonnes/day)	-20,200
CO_2 Emissions	
Captured (tonnes/day CO_2)	1,772
Emitted (tonnes/day CO_2)	1,164

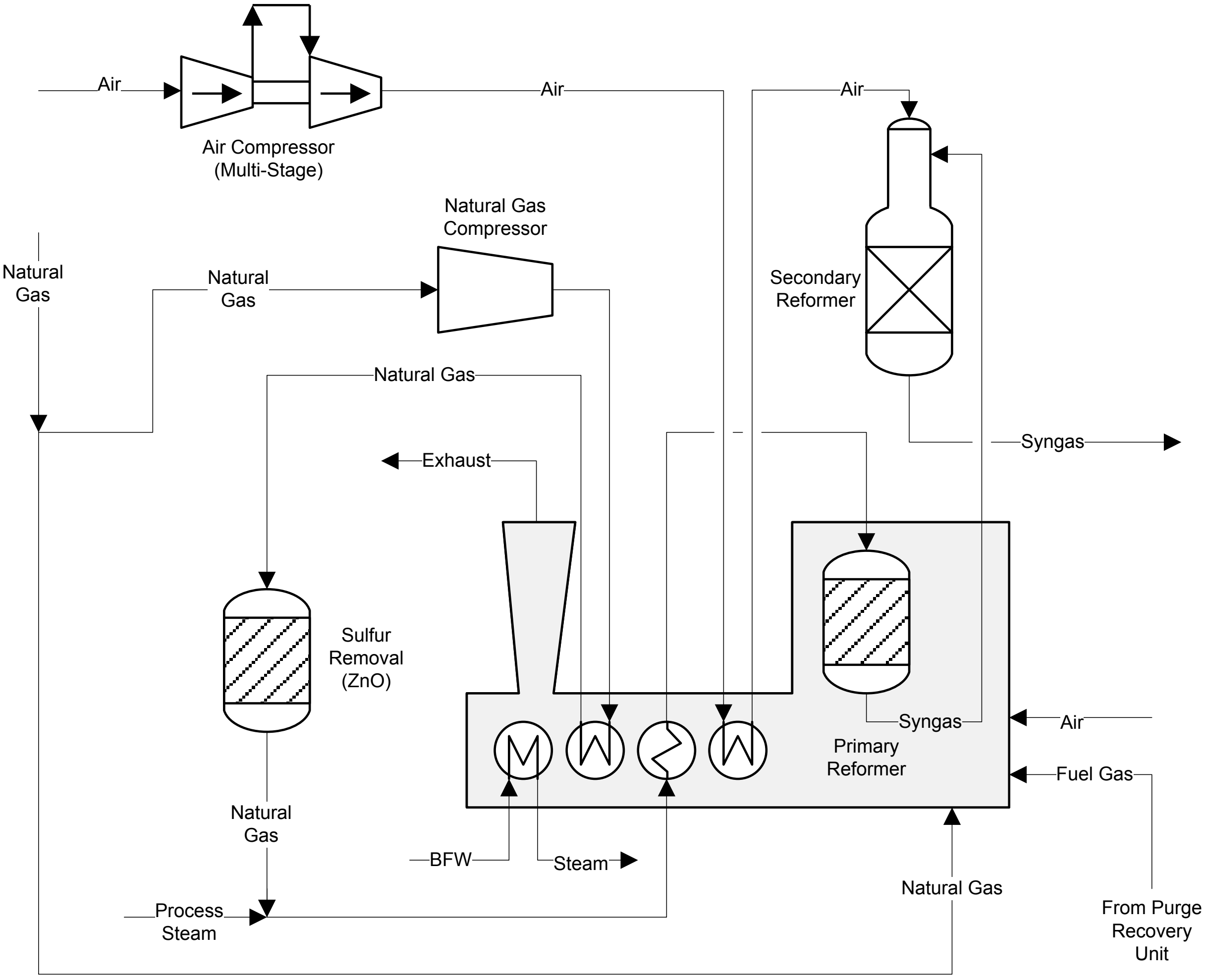

Figure L-3. Schematic of the reforming process
(BFW is boiler feed water)

Table L-2. Heat Addition from Natural Gas

Location	Heat Duty (TJ/day)	Inlet Temperature (ºC)	Outlet Temperature (ºC)
Primary reformer	14.484	538	790
Preheat steam/air into secondary reformer	1.405	842	728
Preheat steam/natural gas into primary reformer	2.568	728	512
Preheat steam before mix with natural gas	1.699	512	362
Preheat natural gas before mix with steam	1.013	362	271
Natural gas preheat	0.309	271	242
Steam preheat	0.056	242	237
Process preheat	0.446	237	195
Process preheat	0.608	195	138

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Appendix M. Corn Wet Milling

Corn wet milling (CWM) is also known as corn refining. Corn is a primary source of starch used in food, paper, and ethanol industries. The objective of CWM is to separate the corn kernel into its main components (starch, germ, fiber, steep liquor, and protein [gluten]) and recover the maximum amount of starch possible from the process. CWM plants in the United States process 100,000 bushels per day, or 2,540 tonnes/day, and operate continuously for nearly 365 days per year (Galtsky et al. 2003). Major CWM outputs are corn sweeteners (corn or glucose syrup, dextrose, and high fructose corn syrup) and ethanol from further processing of starch. Figure shows the yield of corn components from the process (Blanchard 1992; Matz 1991).

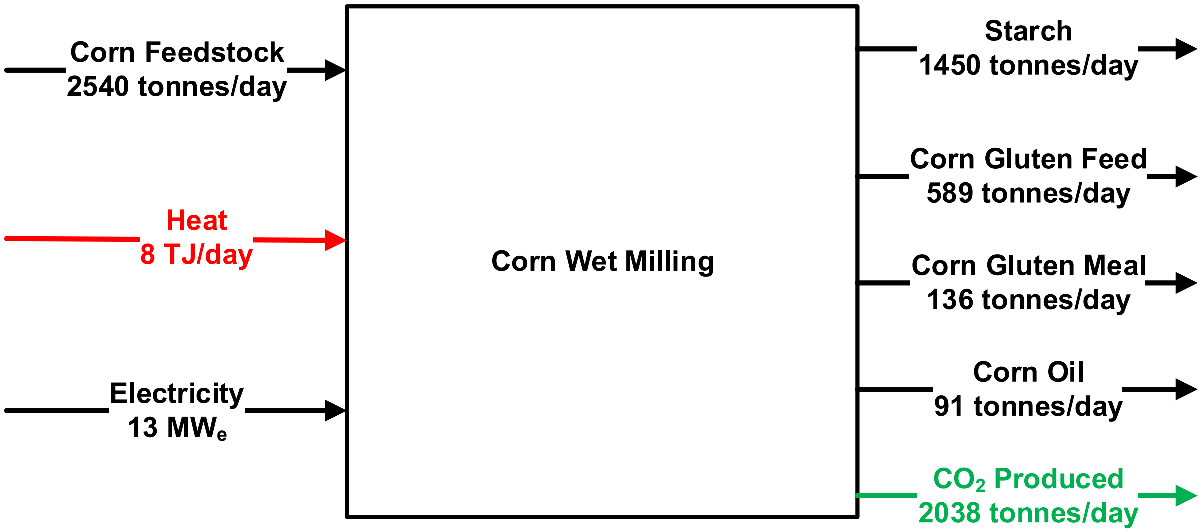

Figure M-1. Material and energy flows for a nominal CWM plant

(Based on 100,000 bushels per day; 1 bushel = 56 pounds or 25.4 kg).

Process Description

As the name suggests, CWM is a wet process; it uses water as a medium for separating the main components, but the output produced is a dry product. The corn kernels are cleaned of all debris and foreign material to prevent (1) clogging of screens, (2) quality effects to the finished product, and (3) increasing viscosity for the main process stream. The CWM process flow diagram is shown in Figure M-2.

Steeping Stage: In the steeping stage, corn kernels are soaked in a solution containing sulfur dioxide (SO_2) and mildly acidic water (lactic acid; $C_3H_6O_3$) with a pH of approximately 4 at about 50°C for 20–36 hours. Steeping occurs in series of tanks referred as steeps, which are operated in continuous batch process. SO_2 avoids the growth of micro-organisms and reacts with proteins to release starch granules. The presence of acidic water contributes to softening the kernel and increasing the SO_2 diffusion speed. Overall efficiency of the CWM process is dependent on the proper steeping of the corn. The water from the corn soak is referred to as steepwater. Steepwater contains soluble material from the corn along with a significant percentage of proteins and sugars. The moisture content in the corn kernel increases from 15%–45% during steeping. The corn does not move, but the steepwater is transferred through different tanks from the oldest steeped corn to the freshest.

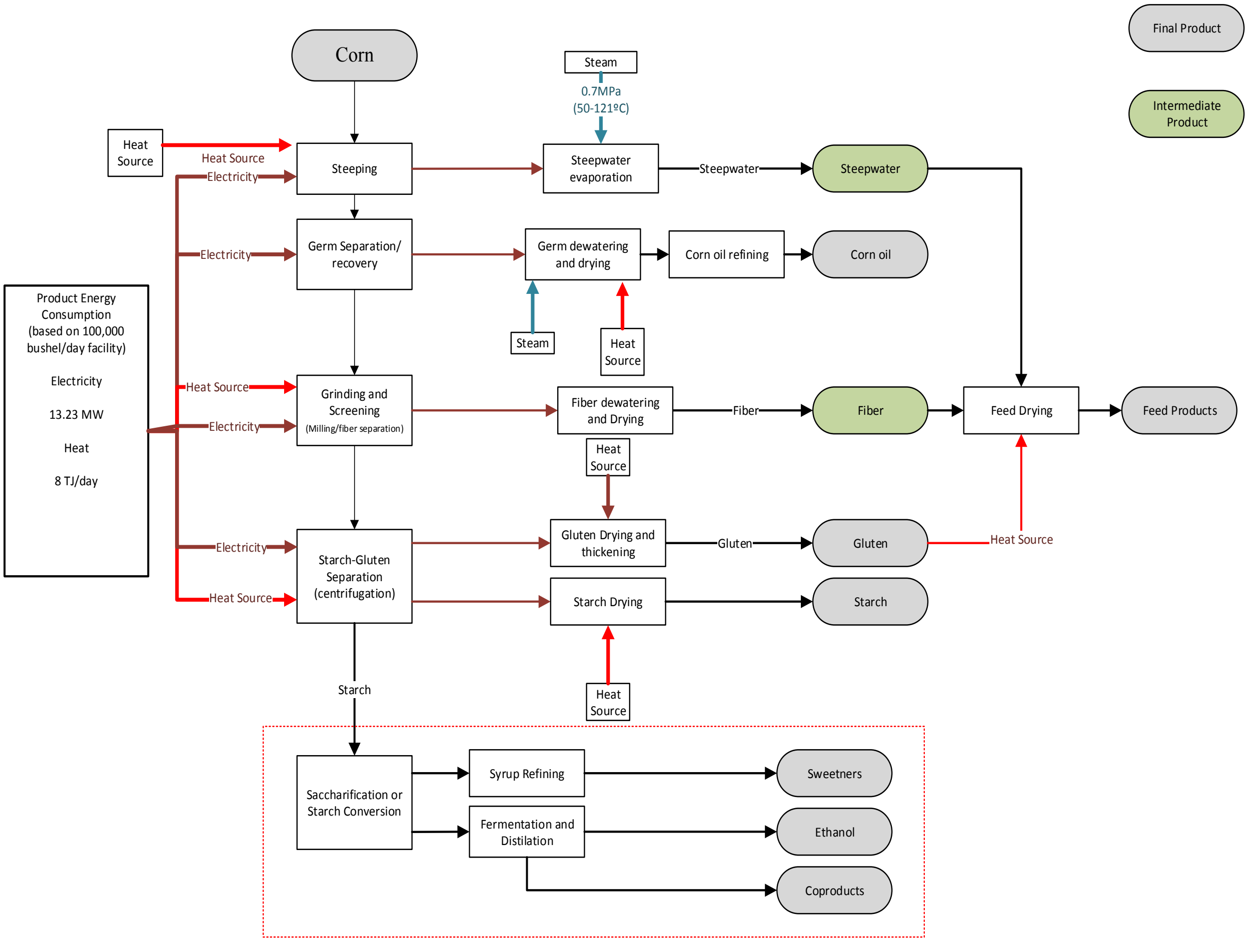

Figure M-2. CWM process diagram

Degermination: The slurry generated by the coarse grinding that follows steeping undergoes a degermination (separation) process to separate the germ from the other components. Corn germ contains most of the oil, which is less dense than water and separated using hydrocyclone separators. The germ is pumped into a series of screens to remove the loose gluten and starch and then washed repeatedly to recover and return all starch to the main stream. To achieve a moisture content of 2%–4%, the germ is dried using a rotary steam tube dryer. The germ could also be dried using a fluidized bed dryer. After the germ is dried, corn oil is extracted through combination of chemical and mechanical processes.

Grinding and Screening: The slurry from hydrocylones undergoes fine grinding and screening to liberate all the starch and gluten from the fiber. This is followed by fiber water wash to recover as much starch and gluten from the main stream as possible. Fiber is then dewatered in two steps: (1) using a screen centrifuge (using a perforated plate screen) followed by (2) a screw press to reduce the moisture content to 10%. Corn steep liquor is added to the moist fiber, and the mixture is dried using a rotary dryer with a co-current hot air stream.

Starch-Gluten Separation: The solution remaining after fiber is extracted is a mixture of starch-gluten that undergoes separation using centrifuges because of the density difference between gluten and starch. Gluten is dewatered by using a filter from a belt vacuum filter or rotary drum filter. Starch that will be sold directly, instead of being converted into ethanol or syrups, needs to be completely dried to a powder. A series of hydrocyclones or the filtering system is the final step used to separate the starch from gluten. Starch slurry then goes through a washing stage and is dried to attain a moisture content of 33%–42% with the help of a spray or film dryer or fluid bed dryers, depending on the batch size.

Saccharification (Starch Conversion): Starch can be modified to produce a broad range of products for various applications. Starch that is not dried goes through the saccharification process to obtain sugar syrups. In this process, starch slurries cannot be held for too long, otherwise microorganisms begin to develop, affecting color, odor, and physical properties of starch.

Energy Usage

CWM is a very energy-intensive industry. The processes for dewatering, drying, and evaporating are major sources of energy consumption (Galitsky et al. 2003).

Table M-1. Description of Pocess End Use in CWM Process

Process	End Use
Starch Drying	Pumping, grinding, separating, and drying the corn product
Gluten Dewater/Drying	Making steam or direct drying
Steam	Evaporation, drying, maintaining process temperature, fermentation, extraction, ethanol recovery, and conversion of starch in refineries

CWM requires electricity and the possible use of steam for steam tube dryers; thus, a combined heat and power plant for cogeneration may be applicable. Table M-2 summarizes the energy end uses for CWM. Currently, most of the CWM plants generate both electricity and thermal energy heat by burning coal or natural gas to generate steam. Table M-3 provides the estimated energy consumption for processes in CWM operations.

Table M-2. Description of Energy End Use in CWM Process

Utilities	End Use
Electricity	Pumping, grinding, separating, and drying the corn product
Fuel (Natural Gas or Coal)	Making steam or direct drying
Steam	Evaporation, drying, maintaining process temperature, fermentation, extraction, ethanol recovery, and conversion of starch in refineries

Table M-3. Energy Use in CWM Process

Corn Wet Milling (Based on 2010 EIA MECS)		
Facilities	67	
Average Annual Energy Use		
Natural Gas (TJ/day)	2.271	
Coal (TJ/day)	4.816	
Heat (TJ/day)	8	
Electricity (MW)	13	
Corn Wet Milling (Based on 100,000 bushel/day Facility)		
Corn Feedstock (tonnes/day)	2,540	
Process	Electricity Consumed (MW_e/day)	Heat Required (TJ/day)
Corn Receiving	0.0014	
Steeping	0.0007	0.0025
Steepwater Evaporation	0.0018	2.058
Germ Recovery (Grinding and Washing)	0.0035	
Germ Dewatering and Drying	0.0015	0.715
Fiber Recovery	0.0072	
Fiber Dewatering	0.0013	
Protein (Gluten) Recovery	0.0033	
Gluten Thickening and Drying	0.0017	0.375
Starch Washing	0.0016	
Starch Dewatering and Drying	0.0089	2.848
Gluten Feed Dryer	0.0033	2.365
Total Power (MW_e)	13.23	
Total Heat Required (TJ/day)		8.36
Emissions		
Avg. CO_2 Emissions (tonnes/day)[a]	2,038	
Steam Temperature and Quality (0.7 MPa)		
Process	Steam Temperature (°C)	
Steeping	50–121	
Steepwater Evaporation	50–121	
Germ Dewatering and Drying	130–168	

[a] CO_2 emissions are based on EPA-reported CO_2 emissions from 24 facilities (744,000 tonnes of CO_2).

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Appendix N. Lime and Cement Manufacturing

Limestone (calcium carbonate or $CaCO_3$) is an essential raw material for production of lime/quicklime (CaO)[4]. It is often associated with some amount of magnesium carbonate ($MgCO_3$), which is then referred to as dolomite when they occur in approximately equal proportions. Limestone and dolomite are widely used to produce cement block, cinder block, so-called cultured stone, mortar, and other related construction materials. It is blended with shale and clay minerals (and coal flyash) containing SiO_2, Al_2O_3, and Fe_2O_3 to produce calcium alumno-silicates—known as Portland cement—in very high-temperature gas/solid-fired cement kilns approaching temperatures of up to 1,500°C (Oates 2010). In 2015, U.S. production of lime and cement is 5.4% and 2% of the world production, respectively.

Cement making consists of three stages:

1. Grinding a mixture of limestone and clay or shale to make a fine "rawmix" (see Rawmill)
2. Heating the rawmix to sintering temperature (up to 1,500°C) in a cement kiln
3. Grinding the resulting clinker to make cement.

In the second stage, the rawmix is fed into the kiln and gradually heated by contact with the hot gases from combustion of the kiln fuel. Successive chemical reactions take place as the temperature of the rawmix rises:

- 70–110°C - Free water is evaporated.
- 400–600°C - Clay-like minerals are decomposed into their constituent oxides; principally SiO_2 and Al_2O_3.
- 500–900°C – Limestone and dolomite commence decomposition to form CaO, MgO, and CO_2.
- 650–900°C - Calcium carbonate reacts with SiO_2 to form belite (Ca_2SiO_4).
- 900–1,050°C - All remaining limestone and dolomite decompose.
- 1,300–1,450°C - Partial (20%–30%) melting takes place, and belite reacts with calcium oxide to form tri-calcium, alumno-silicate (alite or $Ca_3O \cdot SiO_4$), which is the characteristic constituent of Portland cement. In the presence of Al_2O_3, tricalcium aluminate $(CaO)_3$ Al_2O_3, or in the presence of Fe_2O_3, tetracalcium alumino-ferrite $(CaO)_4$ Al_2O_3 Fe_2O_3 is formed. Each of these can help accelerate the rate of hydration or setting of cement.

Cement kilns are primarily firing with coal, petroleum coke, heavy fuel oil, natural gas, landfill off-gas, and oil refinery flare gas. The clinker is brought to its peak temperature mainly by radiant heat transfer, and a bright (i.e., high emissivity) and a hot flame is essential for this.

In addition to these primary fuels, various combustible waste materials have been fed to kilns—notably used tires—which are very difficult to dispose of by other means. In theory, cement kilns are an attractive way of disposing of hazardous materials.

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[4] Lime and quicklime are interchangeably used in the industry.

Compared to cement kilns, lime manufacturing kilns are operated at lower, but still relatively high, temperatures of 900–1200°C to dissociate calcium and magnesium carbonates into their respective oxides and CO_2, according to the following reactions:

$CaCO_3$ + heat --> CO_2 + CaO (calcium lime)

$CaCO_3.MgCO_3$+ heat --> $2CO_2$ + CaO.MgO (dolomitic lime)

Commercial lime products fall into three main categories: calcium limes, hydraulic limes, and dolomitic limes. Over 95% of limestone is produced by open-cast quarrying, with less than 5% being extracted by underground mining.

Lime grade varies based on chemical and physical properties of limestone, type of lime kiln, fuel used, kiln settings, and control parameters and how the lime is processed. Figure N-1 and Figure N-2 summarize the material and energy flow for a nominal size lime and cement production plant.

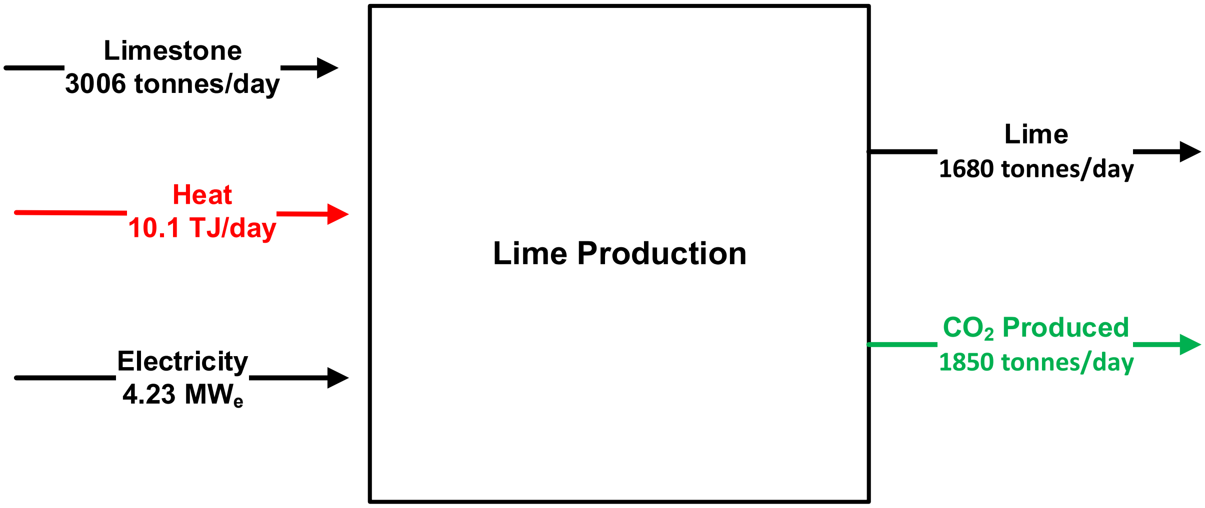

Figure N-1. Material and energy flow summary for a nominal lime production plant

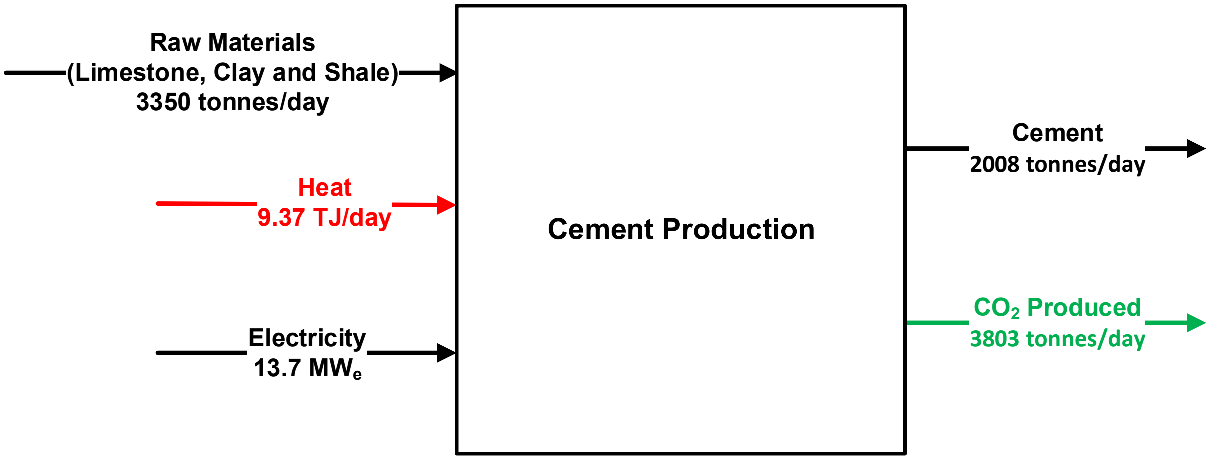

Figure N-2. Material and energy flow summary for a nominal cement production plant

Proper lime kiln design is important to achieve specific characteristics and quality. Lime kilns can be subdivided into three main groups: countercurrent shaft kilns, shaft kilns with concurrent flow, and rotary kilns. Table N-1 provides net heat and electricity usage for the different types of kilns commonly used. The rotary kiln is the most prevalent type used in the United States, accounting for about 90% of all lime production.

Table N-1. Energy Use by Different Types of Lime Kiln (Oates 2010)

Kiln Type	Net Heat Usage (KJ/kg)	Electricity Usage (kWh/t)
Parallel-Flow Regenerative	3,600–4,200	18–25
Annular Shaft	3,950–4,600	18–35
Countercurrent Shaft	4,200–5,000	20–40
Preheater Rotary	5,000–6,000	20–45
Long Rotary	6,500–7,500	10–15

As with cement production, lime kilns are usually fired with a carbon fuel. Electrical power is mostly used for limestone screening, grinding, and hydrating of lime (post calcining). A process flow diagram for the production of lime is shown in Figure and for the production of cement is shown in Figure .

Feedstock: The feedstock for lime production is calcium carbonate and/or calcium magnesium carbonate mineral that is extracted from quarries to produce lime or dolomitic lime.

Quarry and Crushing: The limestone is quarried and crushed to a particle size, varying between 15 and 40 mm, before being fed into the kiln (Hokfors et al. 2012).

Drying, Heating, and Calcination: The limestone feed enters the kiln at the upper end of the kiln and the rotation of the kiln forces the material downwards. As the limestone comes in direct contact with the hot gases, the limestone is dried, heated, and then calcined. As shown for the steps in Portland cement manufacturing, limestone itself is converted to calcium oxide at temperatures ranging between 900°C and 1,200°C. The product of calcining is often referred to as quicklime (or just lime) and dolomite lime when it contains a high amount of magnesium oxide. The clinker product is crushed or pulverized, depending on its intended use.

Either quicklime or dolomitic lime may be hydrated or combined with water by using a slaker to produce slaked lime and slaked dolomitic lime. This is an exothermic reaction that generates 1.14 MJ/kg of CaO (Stork et al. 2016).

The theoretical minimum energy consumption in a lime kiln is 3.18 GJ/tonne of CaO produced (Stork et al. 2016), assuming complete conversion of limestone into lime. The majority of the energy consumption occurs in the lime production process where the heat is required in the kiln for calcination. The electricity consumption in the lime production process is small (on the order of 60 kWh/tonne of lime product). Table and Table provide the average CO_2 emissions and net energy requirement for production of lime, respectively.

Table N-2. Average CO_2 Intensities for Various Lime Products

Lime Product	Process Emissions[a]	Combustion Emissions[a]	Electricity Emissions[a]	Total Emissions[a]
Quicklime	0.751	0.322	0.019	1.092
Dolomitic Lime	0.807	0.475		1.301

[a]Emissions in tonnes of CO_2 per tonne lime product.
Stork et al. 2016.

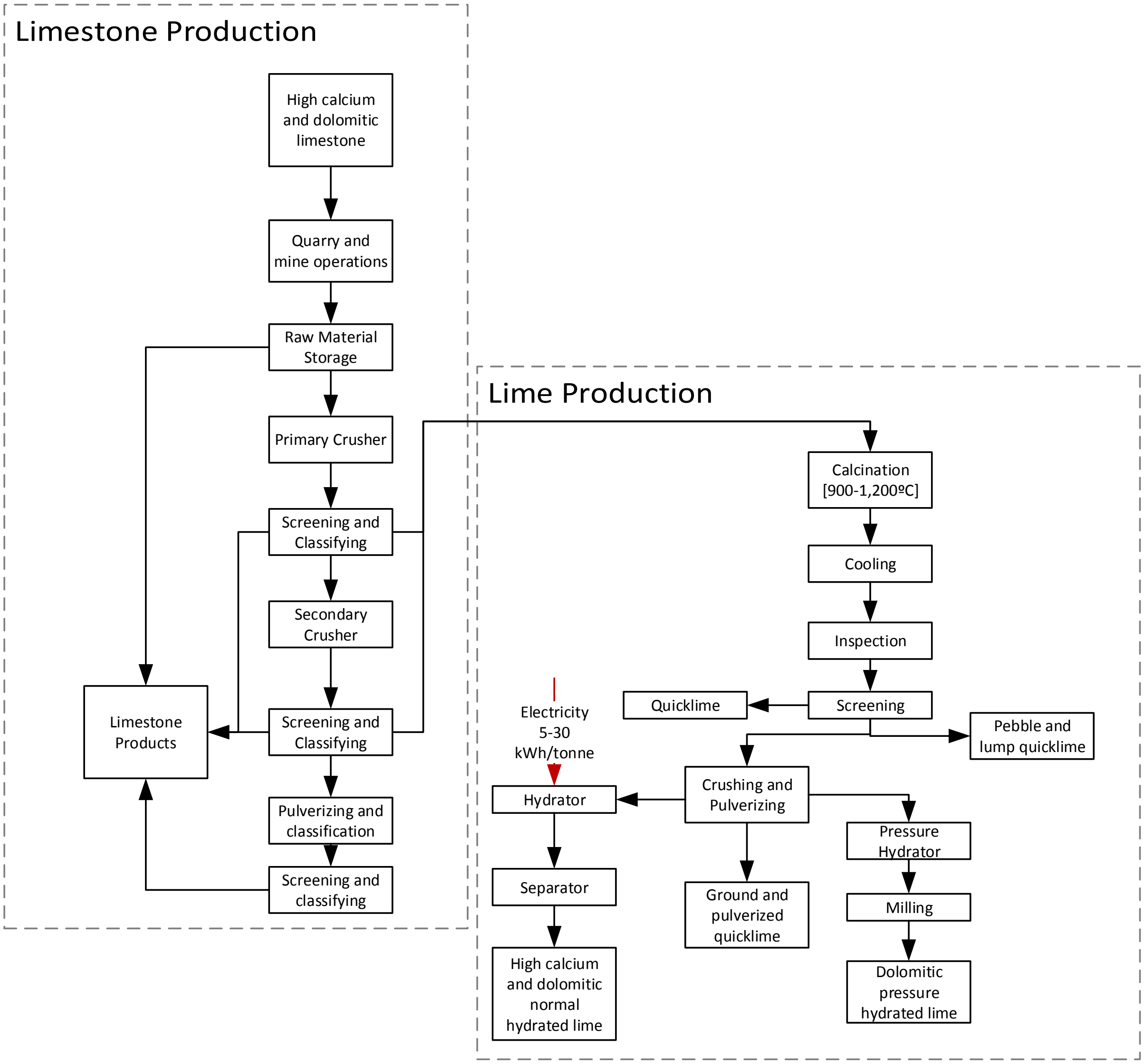

Figure N-3. Lime production process flow diagram

(EPA 1998; DOE 2013; Bleiwas 2011)

Cement Production Process

The production process for cement can be divided into the following steps:

Mining, Quarrying, and Screening: Raw materials used for cement production are limestone, shale, and clay. Limestone provides the required calcium oxide, while shale, clay, and other materials provide most of the silicon, aluminum, and iron oxides required to produce Portland cement. Limestone is mostly extracted from open-face quarries. The size reduction takes place by processing the raw material through a series of crushers.

Feed Preparation for Kiln: After size reduction, the raw materials are further reduced in size by grinding. There are two processing methods to produce cement—mainly dry processing and wet processing. In dry processing, the raw materials are ground into a flowable powder in horizontal ball mills or vertical roller mills. The moisture content in the kiln feed of the dry kiln is typically around 0.5%. In the wet process, the raw materials are ground with water to produce slurry (containing 24%–48% water).

Clinker Production (Pyro-Processing): Clinker production is the most energy-intensive stage in cement production. Clinker is produced by pyroprocessing in large kilns. The main type of kiln used in the industry is the rotary kiln. The kiln evaporates the inherent water in the feed, calcines the carbonate constituents (calcination), and helps form cement minerals. The capacity of larger units is up to 3,600 tonnes of clinker per day. Dry rotary kiln feed material has a much lower moisture content (0.5%), thereby reducing the need for evaporation and reduction of kiln length. After the clinker is formed in the rotary kiln, it is cooled rapidly to minimize the formation of a glass phase and to ensure the maximum yield of alite (tricalcium silicate) formation, a required component for the hardening properties of cement.

Grinding Mill Finish: To produce powdered cement, the nodules of cement clinker are ground to the consistency of very fine powder. In the process, other additives are added, such as gypsum to control the setting properties of the cement.

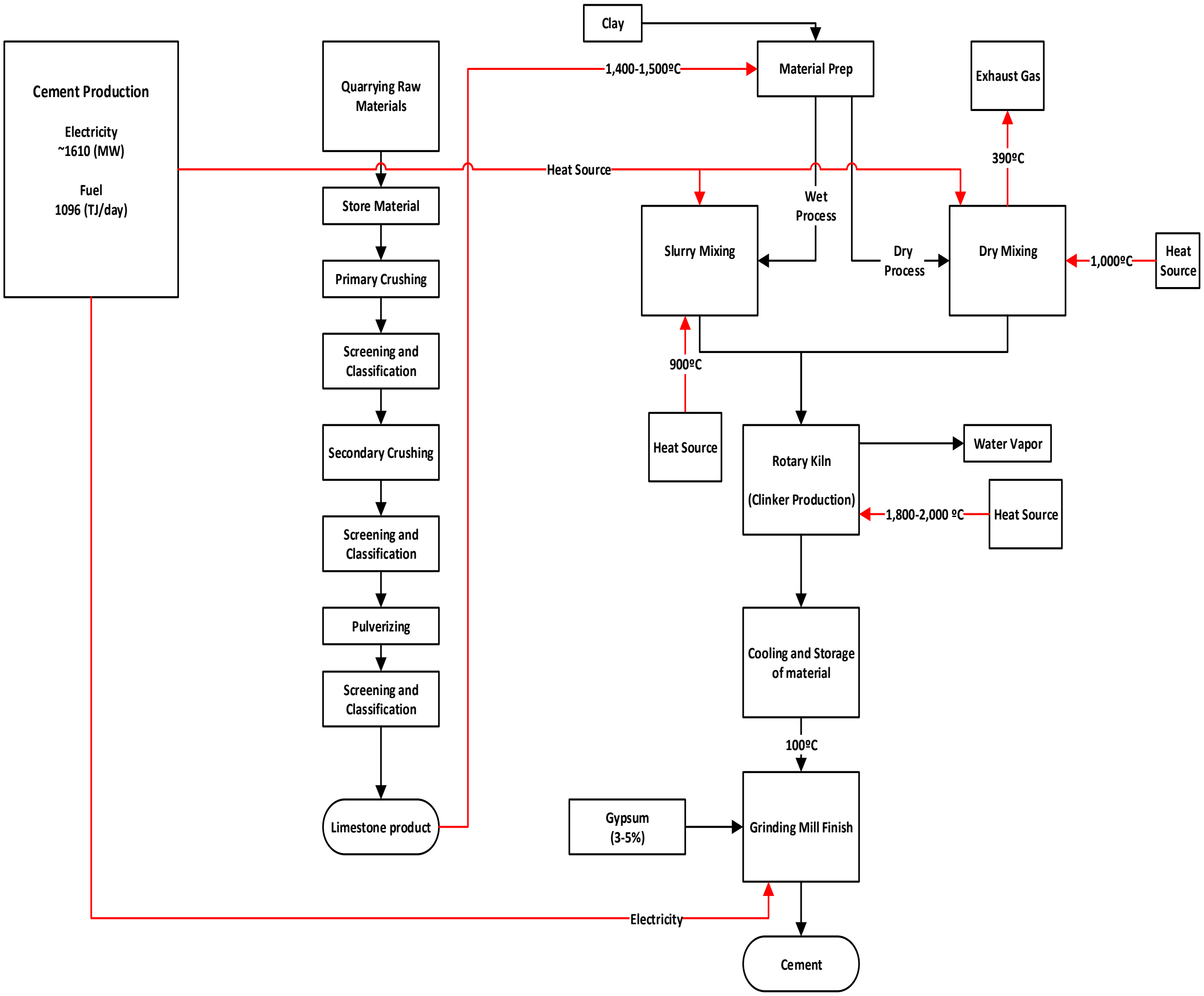

Figure N-4. Cement production process

Table N-4 provides the net energy requirement and CO_2 emissions for production of cement, respectively.

Energy Summary

Conversion of calcium carbonate to calcium oxide is achieved by heating the limestone to drive off CO_2. The associated equation, with approximate molecular weight is (Hill and Mason 1997):

$$100\ CaCO_3 + \text{heat} \dashrightarrow 44\ CO_2 + 56\ CaO$$

Thus, 1 tonne of limestone produces 560 kg of lime.

Table N-3. Lime Production Energy Use[a] (Production and Facilities Based on 2015)

Lime Industry	
Facilities in United States	31
Production (tonnes/yr)	
Lime	
United States	1.90E+07
World	3.50E+07
Inputs (tonnes/day)	
Limestone (United States)	9.32E+04
Lime (United States)	5.21E+04
Utilities	
Rotary Kiln	
Total Heat Usage (TJ/day)	
Fuel (Natural Gas/Coal/Oil) (TJ/day)	3.12E+02
Avg. Heat Usage (TJ/day)	1.01E+01
Total Electricity Usage (MW_e)	1.31E+02
Avg. Electricity Usage (MW_e)	4.23E+00
Emissions (tonnes/day)	
CO_2 Emissions	5.73E+04

[a] Based on production in 2015 (Corathers 2016).

Table N-4. Cement Production Energy Use[a] (Production and Facilities Based on 1999)

Cement Industry	
Facilities	117
Production (tonnes/yr)	
Cement	
United States	8.60E+07
World	1.60E+09
Inputs (tonnes/day)	
Raw Materials (Limestone, Clay, and Shale)	3.92E+05
(26% used for wet process kilns; 74% used for dry process kilns)	
Outputs (tonnes/day)	
Cement (United States)	2.35E+05
Utilities	
Fuel (TJ/day)	1.10E+03
Avg. Fuel Consumption (TJ/day)	9.37E+00
Electricity (MW)	1.61E+03
Avg. Electricity Consumption (MW)	1.37E+01
Emissions (tonnes/day)	
CO_2 Emissions	4.45E+05

[a] Worrell and Galitsky (2008).

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Appendix O. Potash, Soda, and Borate Mineral Mining

Potash, borates, and soda ash are industrial minerals, primarily used as feedstocks for other industries.

Potash

Potash refers to a variety of mined and manufactured salts, containing the elemental potassium in water-soluble form. Potash historically refers to potassium carbonate (recovered in iron pots from leaching wood “ashes” with water [DOE-EERE 2012]). In 1997, the United States produced 2.9 million tonnes (~ 1.4 million tonnes in K_2O Eq.) at six facilities with average CO_2 emission of 467 tonnes per year per facility (based on CO_2 emission at rates of 0.002 kg/kg K_2O). The electricity and heat requirement for this industry is very low compared to other industries that have been studied. Thus, this industry will not be discussed further.

Borates

Boron-containing minerals are referred to as borates. The three most common minerals that serve as a source of borates are: borax (tincal) and kernite, which are sodium borates; ulexite, a sodium-calcium borate; and colemanite, a calcium borate. Borates are essential for imparting strength, durability, heat, and impact resistance to glass and glass fibers. In 2000, the United States produced 1.1 million tonnes of borates (DOE-EERE 2012), which was reduced to 536,000 tonnes in 2003. The energy consumption and emission rates are hard to decipher from the literature because of the minimal production of borates and thus will not be discussed further.

Soda Ash

The term soda ash is used for sodium carbonate (Na_2CO_3), a chemical refined from trona or sodium sesquicarbonate ($Na_2CO_3.NaHCO_3.2H_2O$) and from sodium-carbonate-bearing brines (using the Solvay process). In 2011, the United States produced 10.7 million tonnes of soda ash, increasing to 11.7 million tonnes in 2015. Most of the soda ash is produced using trona; thus, more details are provided on this process. The following energy summary (Figure O-1) and energy breakdown with emissions (Table O-1) are based on a facility producing 4 million tons per year. This scale corresponds to each of the four plants near Green River, Wyoming. Each plant uses an estimated total of 625 MW_t (54 TJ/day) of heat. Using this case study, energy requirements for each individual process can be broken down with the net water requirement and CO_2 emissions. Table O-1, provides the net energy consumption for each individual process for production of soda ash. Figure O-1 provides a process flow diagram of the production of soda ash from trona.

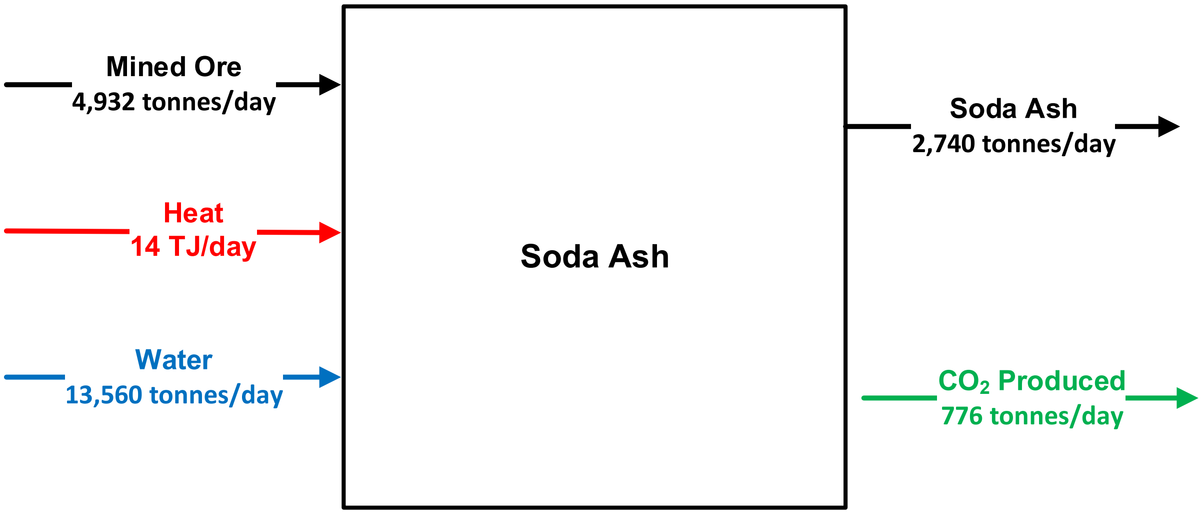

Figure O-1. Material and energy flows for a nominal soda ash (processing from Trona) production plant

Process and Description

Soda Ash Mining: A variety of mining methods are used in soda mining, such as room-and-pillar mining, conventional mining, continuous mining, and solution mining.

Crushing and Calcination: After mining and crushing, the trona ore is calcined in rotary gas-fired calciners operating at 150–300°C. The calcination process removes water and CO_2 from the ore, leaving behind mainly sodium carbonate (soda ash) and insoluble compounds.

Dissolving, Settling, Filtration, and Crystallization: Sodium carbonate is dissolved in water, such that insoluble clays and iron compounds could be physically separated from the sodium carbonate solution. Further, organic contaminants in trona are adsorbed onto activated carbon beds prior to the crystallization process, such that organics do not interfere with the crystal growth rate.

Drying: The crystals are further sent to hydrocylones and are dewatered in centrifuges, after which they are fed to steam tube dryers. Crystals are dehydrated into dense soda ash and are then sent to storage or shipment.

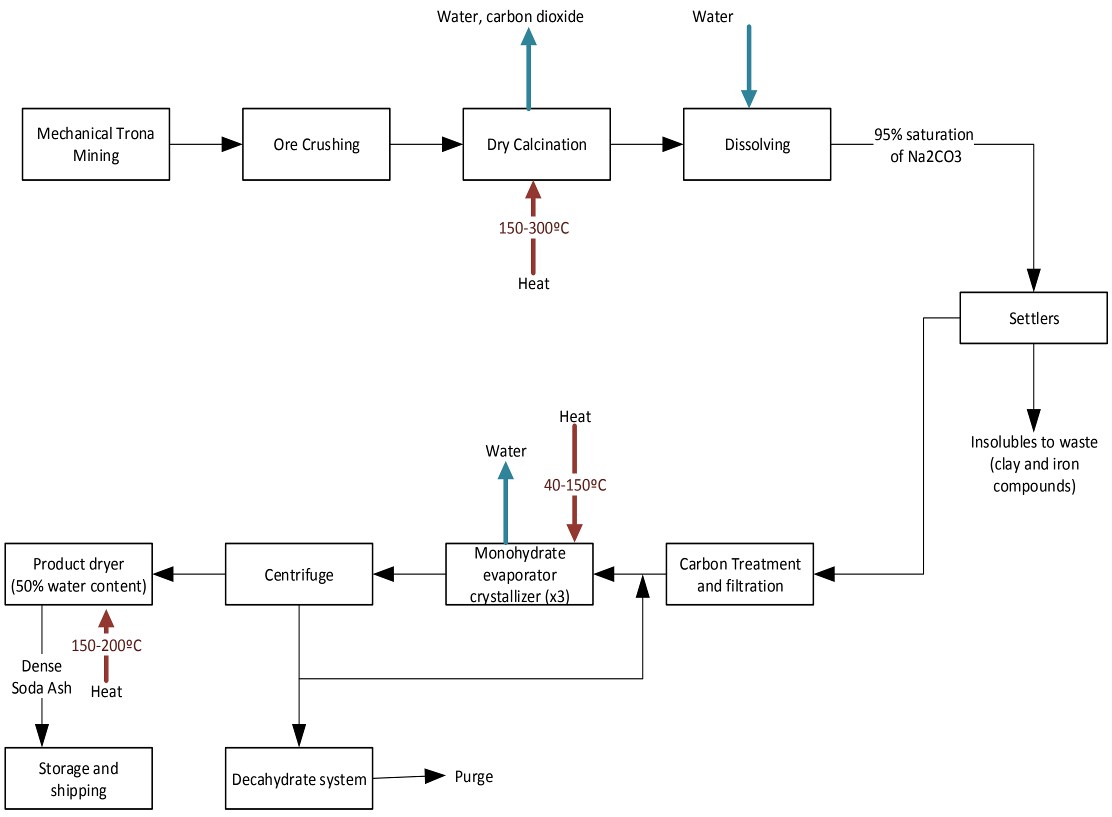

Figure O-2. Process flow for trona ($Na_2CO_3.NaHCO_3.2H_2O$) processing to produce soda ash (Na_2CO_3)

Table O-1. Energy Consumption Breakdown for Soda Ash Production Process from Trona

Soda Ash (Trona) Process Results		
Facilities (Green River, WY)		4
Heat Requirement (TJ/day)		54
Inputs		
	Mined Ore (tonnes/day)	19,726
Outputs		
	Soda Ash (tonnes/day)	10,959
Utility Summary		
	Dry Calcination (TJ/day)	14.5
	Crystallizer (TJ/day)	12
	Product Dryer (TJ/day)	27.6
Water (tonnes/day)		
	Dry Calcination Process	4,088
	Dissolving	25,078
	Crystallizer	14,119
	Product Dryer	10,959
	Total Water Consumption (tonnes/day)	54,243
CO_2 Emissions		
	Emitted (tonnes/day)	3,105

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