Model Documentation Report: Industrial Demand Module of the National Energy Modeling System

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Independent Statistics and Analysis
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Contents

Table of Figures

Table of Tables

1. Introduction

This report documents the objectives and analytical approach of the National Energy Modeling System (NEMS) Industrial Demand Module (IDM). The report catalogues and describes module assumptions, computational methodology, parameter estimation techniques, and module source code. This edition of documentation is written for the NEMS version corresponding to the *Annual Energy Outlook 2025*.

This document serves three purposes. First, it is a reference document providing a detailed description of the NEMS Industrial Demand Module for model analysts, users, and the public. Second, this report meets the legal requirement of the U.S. Energy Information Administration (EIA) to provide adequate documentation in support of its models (Public Law 94-385, section 57.b2). Third, it facilitates continuity in module development by providing documentation from which energy analysts can undertake module enhancements, data updates, and parameter refinements in future projects.

Module summary

The NEMS Industrial Demand Module is a dynamic accounting model, bringing together representations of disparate industries and uses of energy in those industries and putting them in an understandable and cohesive framework. The IDM generates long-term (base year 2018 through the year 2050) projections of industrial sector energy demand as a component of the integrated NEMS. From NEMS, the IDM receives fuel prices, employment data, and the value of industrial shipments.

The NEMS Industrial Demand Module estimates energy consumption by energy source (fuels and feedstocks) for 18 manufacturing and 3 non-manufacturing industries. The manufacturing industries are classified as either energy-intensive manufacturing industries or non-energy-intensive manufacturing industries. The manufacturing industries are modeled using detailed process flows or end-use accounting procedures. In addition, some of the end-use submodules are modeled in somewhat more detail. The energy-intensive bulk chemicals industry is subdivided into four industry components, and the food industry is also subdivided into four components. The energy-intensive industries of cement and lime, aluminum, glass, iron and steel, and pulp and paper have detailed process flow submodules. The non-manufacturing industries are represented in less detail. The IDM projects energy consumption at the census region level; energy consumption at the census division level is allocated by using data from the State Energy Data System (SEDS) for 2022.[1] The national-level forecasts reported in the December 2024 *Short-Term Energy Outlook* (STEO)[2] were allocated to the census divisions, also using the SEDS 2022 data.[1] The four census regions are divided into nine census divisions and are listed in Table 1.

[1] U.S. Energy Information Administration, *State Energy Data System Report 2022*, issued June 28, 2024, http://www.eia.gov/state/seds/.

[2] U.S. Energy Information Administration, *Short-Term Energy Outlook*, December 2024 https://www.eia.gov/outlooks/steo/.

Table 1. Census regions and census divisions

Census region	Census divisions	States
1 (East)	1,2	Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont
2 (Midwest)	3, 4	Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, North Dakota, Nebraska, Ohio, South Dakota, and Wisconsin
3 (South)	5, 6, 7	Alabama, Arkansas, Delaware, District of Columbia, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, and West Virginia
4 (West)	8, 9	Arizona, Alaska, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming

Source: U.S. Census Bureau, https://www2.census.gov/geo/pdfs/maps-data/maps/reference/us_regdiv.pdf.

Unless otherwise noted, each manufacturing industry is modeled as three components: the process and assembly component (PA), the buildings component (BLD), and the boiler, steam, and cogeneration component (BSC). For the manufacturing industries, the PA component is separated into the major production processes or end uses. The non-manufacturing industries (agriculture, construction, and mining) have a different component structure. Agriculture PA includes the following components: irrigation, buildings, and vehicles. Construction includes buildings, civil engineering, and trade components. Mining includes vehicles and production components.

Archival media

The module is archived as part of the National Energy Modeling System production runs used to generate the *Annual Energy Outlook 2025* (AEO2025).

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Organization of this report

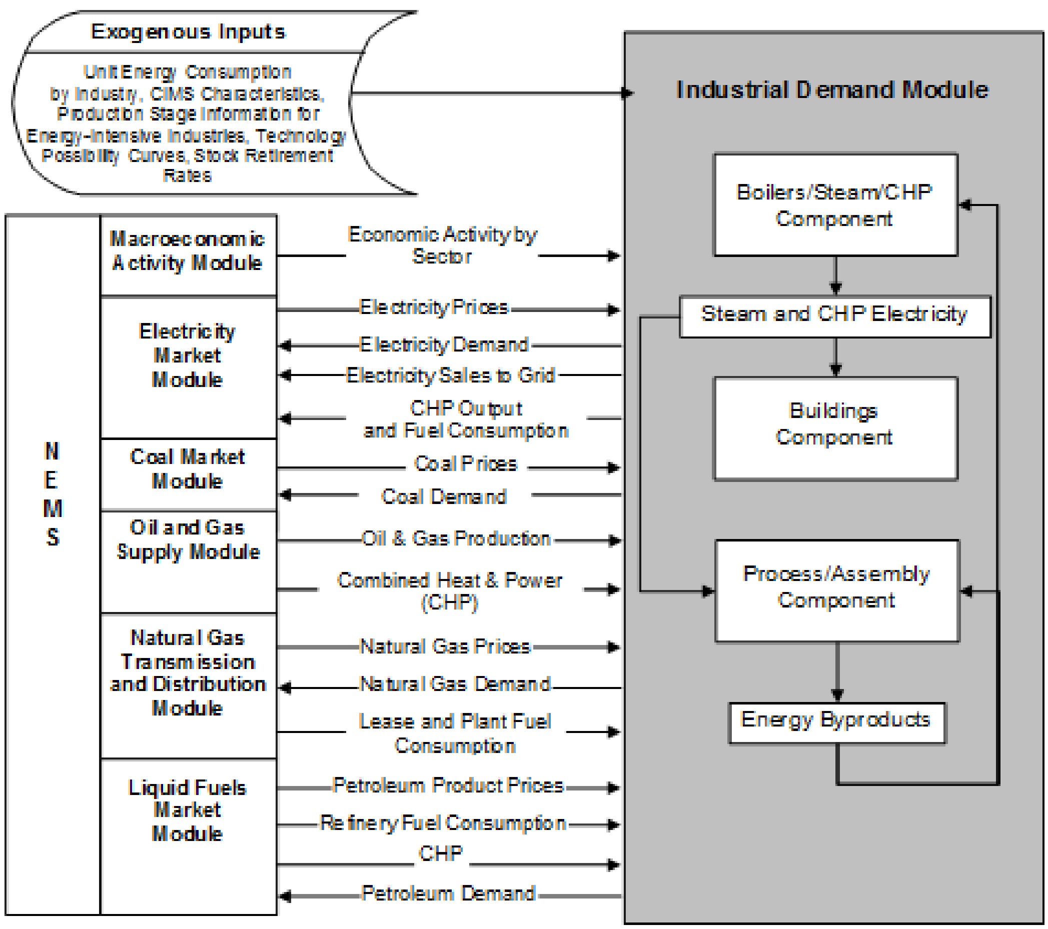
Chapter 2 discusses the purpose of the NEMS Industrial Demand Module, detailing its objectives, input and output variables, and the relationship of the IDM to the other modules of NEMS. Chapter 3 describes the rationale behind the IDM design, providing insights into further assumptions used in the module. The first section in Chapter 4 provides an outline of the module. The second section in Chapter 4 provides a description of the principal module subroutines, including the key computations performed and key equations solved in each subroutine.

The appendices to this report provide supporting documentation for the IDM. Appendix A is the module abstract. Appendix B lists the input data for AEO2025. Appendix C provides industrial group descriptions. Appendix D details methodology for carbon capture modeling in the cement industry. Appendix E is a bibliography of data sources and background materials used in module development.

2. Module Purpose

The National Energy Modeling System (NEMS) Industrial Demand Module (IDM) was designed to project industrial energy consumption by fuel type and industry as defined in the North American Industrial Classification System (NAICS).[3] The IDM generates long-term projections of industrial sector energy demand as a component of the integrated NEMS, going from a base year of 2018 through 2050. From the other components of NEMS, the IDM receives fuel prices, employment data, and the value of shipments, which are expressed in 2012 dollars, for industrial activity. Based on the values of these variables, the IDM passes back to NEMS estimates of fuel consumption (including feedstocks and renewables) for each of 24 industry groups. The IDM projects energy consumption at the census region level; energy consumption is allocated to the census division-level based on the latest State Energy Data System (SEDS) data.

Figure 1. Industrial Demand Module interactions within the National Energy Modeling System (NEMS)



Source: U.S. Energy Information Administration

[3] U.S. Department of Commerce, U.S. Census Bureau, North American Industry Classification System (2017)—United States (Washington, DC, 2017).

Figure 1 shows the IDM inputs from and outputs to other NEMS modules. The NEMS Integrating Module activates the IDM one or more times during the processing for each year of the projection period. On each occurrence of module activation, the processing flow follows the outline shown in Figure 1. Note that all inter-module interactions must pass through the Integrating Module. For the IDM, the Macroeconomic Activity Module (MAM) is critical. The MAM supplies industry value of shipments and employment for the IDM subsectors. Ultimately, these two drivers are major factors influencing industrial energy consumption over time. The second most important influencing factor is the set of energy prices provided by the various supply modules.

Projected industrial sector fuel demands generated by the IDM are used by NEMS to calculate the supply and demand equilibrium for individual fuels. In addition, the NEMS supply modules use the industrial sector outputs in conjunction with other projected sectoral demands to determine the patterns of consumption and the resulting amounts and prices of energy delivered to the industrial sector.

The IDM is an annual energy module and, as such, does not project seasonal or daily variations in fuel demand or fuel prices. We designed the module primarily for use in applications such as the *Annual Energy Outlook* (AEO) and other analyses of long-term energy-economy interactions.

The module can also be used to examine various policy, environmental, and regulatory initiatives. For example, energy consumption per dollar of shipments is, in part, a function of energy prices. Therefore, the effect on industrial energy consumption of policies that change relative fuel prices can be analyzed endogenously in the module.

The IDM can also endogenously analyze specific technology programs or energy standards. The module distinguishes among the energy-intensive manufacturing industries, the non-energy-intensive manufacturing industries, and the non-manufacturing industries. Variation in the level of representational detail and other details of IDM structure affect the suitability of the module for specific analyses.

3. Module Rationale

Theoretical approach

The Industrial Demand Module (IDM) can be characterized as a dynamic accounting module, combining economic and engineering data and knowledge. Its architecture brings together representations of the disparate industries and uses of energy in those industries, combining them in an understandable and cohesive framework. An explicit representation of the varied uses of energy in the industrial sector is used as the framework on which to base the dynamics of the module.

One of the overriding characteristics of the industrial sector is the heterogeneity of industries, products, equipment, technologies, processes, and energy uses. Adding to this heterogeneity is the inclusion in this sector of not only manufacturing but also the non-manufacturing industries of agriculture, mining, and construction. These disparate industries range widely from highly energy-intensive activities to non-energy-intensive activities. Energy-intensive industries are modeled at a disaggregate level so that projected changes in composition of the products produced will be automatically taken into account when computing energy consumption.

Modeling approach

A number of considerations have been taken into account in building the IDM. These considerations have been identified largely through experience with current and earlier U.S. Energy Information Administration (EIA) modules, with various EIA analyses, through communication and association with other modelers and analysts, as well as through literature review. The primary considerations are listed below.

The IDM incorporates three major industry categories: energy-intensive manufacturing industries, non-energy-intensive manufacturing industries, and non-manufacturing industries. The level and type of modeling and the attention to detail is different for each category.

Each manufacturing industry is modeled using either an end-use submodule approach or a process-flow submodule approach. End-use submodules use three separate but interrelated components, consisting of buildings (BLD), process and assembly (PA), and boiler, steam, and cogeneration (BSC) activities. Process-flow models include a BLD component and a PA component. For aluminum, iron and steel, and paper, the BSC component is modelled within the PA component.

The end-use submodules use a capital stock vintage accounting framework that models energy use in new additions to the stock and in the existing stock. The existing stock is retired based on retirement rates for each industry.

The manufacturing industries are modeled with a structure that explicitly describes the major process flows or major consuming uses in the industry. The IDM uses technology choice to characterize technological change. Manufacturing industries are modeled using a process-flow submodule that allows for changes in technology over time. The cement and lime, aluminum, glass, iron and steel, and pulp and paper industry submodules have been expanded to use technology data from multiple sources and allow for more detailed technology modeling. For other industries, specific technology data may be defined for each production process step or end use, but currently all other industries use the end-use submodule approach. Technology improvement for each technology bundle for each production process step or end use is based on engineering judgment.

The module structure accommodates several industrial sector activities, including fuel switching, cogeneration, renewables consumption, recycling, and byproduct consumption. For the end-use submodules, the principal submodule calculations are performed at the census region level and aggregated to a national total. For the process-flow submodules, the submodule calculations are done at the national level and parsed out to the census regions based on regional macroeconomic data.

Industry categories

The industrial sector consists of numerous heterogeneous industries (Table 2). Each industry is associated with one or more NAICS codes. (NAICS is the North American Industrial Classification System.) The IDM classifies these industries into three general groups: energy-intensive manufacturing industries, non-energy-intensive manufacturing industries, and non-manufacturing industries. We model seven energy-intensive manufacturing industries in the IDM:

- food products
- paper and allied products
- bulk chemicals
- glass and glass products
- cement and lime
- iron and steel
- aluminum

We also model eleven non-energy-intensive manufacturing industries. Starting with AEO2025, the industry formerly known as balance of manufacturing has been disaggregated into four industries, indicated by asterisks next to their names:

- metal-based durables, consisting of fabricated metals
- machinery
- computers and electronics
- electrical equipment and appliances
- transportation equipment
- wood products
- plastic and rubber products
- light chemicals*
- other non-metallic mineral products*
- other primary metals*
- miscellaneous finished goods*

The industry categories are also chosen to be consistent with the categories that are available from the *2018 Manufacturing Energy Consumption Survey* (MECS2018).

Table 2. Industries, NAICS Codes, and Industrial Demand Module industry codes

Industry	North American Industrial Classification System (NAICS) codes	Industrial Demand Module (IDM) industry codes
Energy-intensive manufacturing		
Food products	311	7
Grain and oilseed milling	3112	
Dairy product manufacturing	3115	
Animal processing	3116	
Other food products	311 not elsewhere classified	
Paper and allied products	322	8
Bulk chemicals	Portions of 325	9
Organic chemicals	325110, 32519	
Inorganic chemicals	325120–325180	
Resins and synthetics	3252	
Agricultural chemicals	3253	
Glass and glass products	3272	10
Cement and lime	327310, 327410	11
Iron and steel	331110, 3312, 324199	12
Aluminum	3313	13
Non-energy-intensive manufacturing		
Metal-based durables	332–336	
Fabricated metals	332	14
Machinery	333	15
Computers and electronics	334	16
Transportation equipment	336	17
Electrical equipment, appliances, and components	335	18
Wood products	321	19
Plastic and rubber products	326	20
Light chemicals	325 excluding bulk chemicals 3254–3256, 3259	21
Other non-metallic minerals	327 excluding cement and lime and glass (3271, 327320, 327390, 327420, 3279)	22
Other primary metals	331 excluding steel and aluminum (3314, 3315)	23
Miscellaneous finished goods	All other industries (312–316, 323, 324121, 324122, 324191, 337, 339)	24

Industry	North American Industrial Classification System (NAICS) codes	Industrial Demand Module (IDM) industry codes
Non-manufacturing subsectors		
Agriculture, crop production, and support	111, 1151	1
Agriculture, other	112, 113, 1152, 1153	2
Coal mining	2121, 213113	3
Oil and natural gas extraction	211, 213111, 213112	4
Metal and non-metallic mining	2122, 2123, 213114	5
Construction	23	6

Source: U.S. Department of Commerce, U.S. Census Bureau, North American Industry Classification System (2017)—United States (Washington, DC, 2017).

NAICS = North American Industry Classification System (2017).

In addition, most of asphalt has been moved from construction to miscellaneous finished goods. Asphalt in the latter industry is used in for pavement, shingle, and roofing materials manufacturing.

We model seven of the most energy-intensive manufacturing industries in detail in the IDM. The eighth energy-intensive industry, petroleum refining (NAICS 32411), is modeled in detail in the Liquid Fuels Market Module (LFMM), a separate module of NEMS, and the projected energy consumption from LFMM is included in the manufacturing total. The new Hydrocarbon Supply Module (HSM) models projections of consumption for oil and natural gas extraction (NAICS 211); we also report that consumption in the industrial sector energy consumption totals. These industry groupings facilitate model design and data processing. The primary consideration is the distinction between energy-intensive groups and non-energy-intensive industry groups. The industry categories are also chosen to be as consistent as possible with the categories that are available from the most recent MECS.

Starting with AEO2025, the portion of bulk chemicals dealing with hydrogen production has its own module in NEMS, the Hydrogen Market Module (HMM). We also report the energy consumed to produce hydrogen in some industrial sector energy consumption totals. Some results tables include the consumption of the produced hydrogen and hydrogen-related losses (the difference between the energy input to produce hydrogen and the energy content of the produced hydrogen), while other tables include the fuel, feedstocks, and electricity used for hydrogen production but not the manufactured hydrogen itself. This distinction avoids double-counting of the energy associated with hydrogen.

Energy sources modeled

The IDM estimates energy consumption by 24 industries for primary and secondary energy sources, some of which have nonfuel uses. The energy sources modeled in the IDM are as follows:

Sources used in heat and power applications:

- purchased electricity

- natural gas
- steam coal
- coking coal (including net imports)
- residual oil
- distillate oil
- propane for heat and power
- motor gasoline
- petroleum coke
- other petroleum
- renewables (including biomass and hydropower)

Sources used in nonfuel applications:

- hydrogen feedstocks
- natural gas feedstocks
- hydrocarbon gas liquid (HGL) feedstocks
- petrochemical feedstocks
- asphalt and road oil
- petroleum coke (for aluminum anodes)

In the IDM, byproduct fuels such as waste biomass are always consumed before purchased fuels.

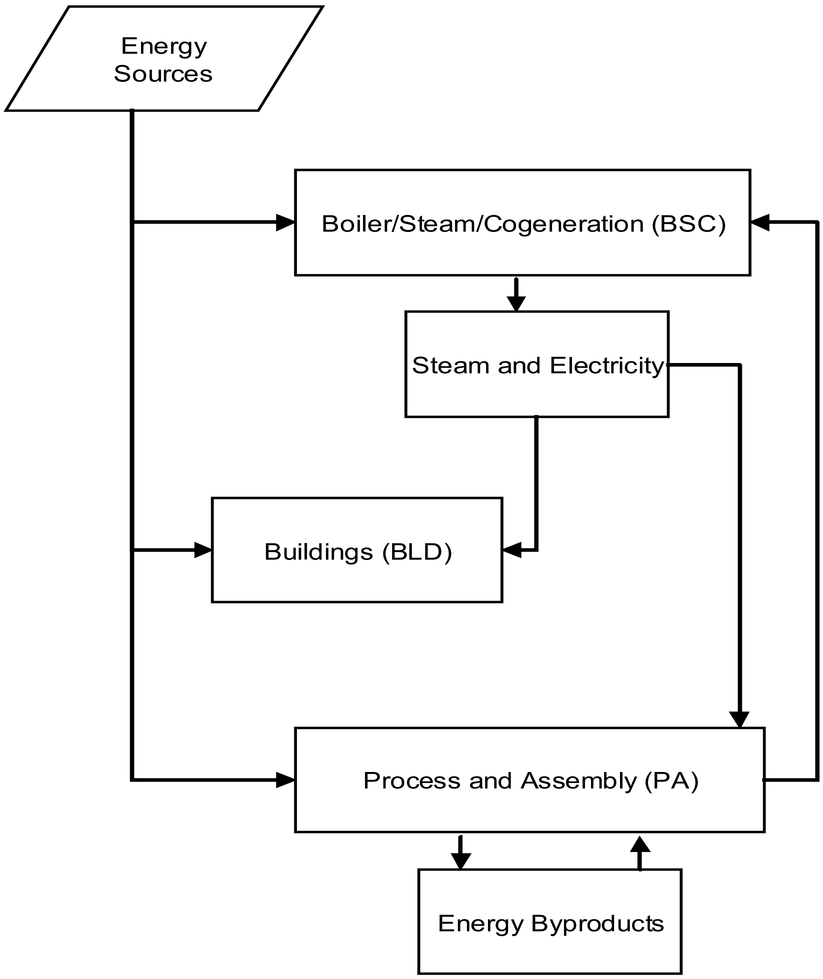
Renewable fuels are modeled in the same manner as all other fuels in the IDM. Renewable fuels are modeled both in the PA component and in the boiler, steam, and cogeneration (BSC) component. The primary renewable fuels consumed in the industrial sector are pulping liquor (a byproduct of the chemical pulping process in the paper industry) and wood.

Recycling

Recycling rates are highly dependent on regulations, the growth of the economy, and issues related to the quality of recycled materials. Secondary processing of aluminum is modeled in the aluminum industry submodule as a process flow and investment option. Iron and steel, pulp and paper, and glass process flow submodules consider recycling in detail. The bulk chemicals end-use submodule also calculates the reduction in HGL demand resulting from plastics recycling.

Industrial Demand Module structure

Figure 2. Basic Industrial Demand Module structure[4]



Source: U.S. Energy Information Administration

For each industry, the flow of energy among the three module components is represented by the arrows in Figure 2. The boiler, steam, and cogeneration (BSC) component satisfies the steam demand from the PA and BLD components. For the manufacturing industries, the PA component is broken down into the major production processes or end uses. Energy consumption in the IDM is primarily a function of the level of industrial economic activity. Industrial economic activity in NEMS is measured by the dollar value of shipments (in constant 2012 dollars) produced by each industry group. The NEMS Macroeconomic Activity Module (MAM) provides the value of shipments by industry (by NAICS code) to the IDM. As the level of industrial economic activity increases, energy consumption typically increases, but at a slower rate than the growth in economic activity.

[4] Process-flow industries model the boiler, steam, and cogeneration component within the process and assembly component.

The amount of energy consumption reported by the IDM is also a function of the vintage of the capital stock that produces the shipments. The end-use submodules assume that new capital stock will consist of state-of-the-art technologies that are, on average, more energy efficient than the existing capital stock. Consequently, the amount of energy required to produce a unit of output using new capital stock is less than that required using the existing capital stock. The energy intensity of the new capital stock relative to base year capital stock is represented by a parameter called a technology possibility curve (TPC), which is estimated for each process step or end use. These TPCs are based on engineering judgments about the likely future path of energy intensity changes. The only exceptions to this methodology are the process and assembly calculations for the cement and lime, aluminum, glass, iron and steel, and pulp and paper industries, which use base year capital stock estimates and then estimate the technology choice associated with new capital stock (related to retirement of existing capital stock) and increases in capital stock (related to increasing shipments). Capital stock for 2018 is used because it is based on survey data from the *2018 Manufacturing Energy Consumption Survey* (MECS), the most recently available MECS survey.

The energy intensity of the existing capital stock for the end-use submodules is assumed to decrease over time, but not as rapidly as the assumed decrease in new capital stock. The decline is due to retrofitting and replacement of equipment from normal wear and tear. Retrofitting existing capacity is assumed to incorporate 50% of the improvement that is achieved by installing new capacity. The process flow submodules select less energy-intensive technology based on fixed costs, fuel costs, and emissions associated with new capital stock. The net effect is that over time the amount of energy required to produce a unit of output declines. Although total energy consumption in the industrial sector is projected to increase, overall energy intensity is projected to decrease.

Energy consumption in the buildings component is assumed to grow at the same rate as the average growth rate of employment and output in that industry. This formulation has been used to account for the countervailing movements in manufacturing employment and value of shipments. Manufacturing employment falls over the projection period, which alone would imply falling building energy use. But because shipments tend to grow, air-conditioned floor space is assumed to increase. Energy consumption in the boiler, steam, and cogeneration (BSC) component is a function of the steam demand of the other two components.

Technology possibility curves, unit energy consumption, and relative energy intensities for end-use submodules

The key computations of the Industrial Demand Module end-use submodules are the unit energy consumption (UEC) estimates made for each NAICS industry group. UEC is defined as the amount of energy required to produce either one dollar's worth of shipments or one unit of physical output. The distinction between existing and new capital equipment is maintained with a vintage-based accounting procedure. In practice, the fuel use in similar capital equipment is the same across vintages. For example, an electric arc furnace primarily consumes electricity no matter whether it is an old electric arc furnace or a new one.

The modeling approach incorporates technical change in the production process to achieve lower energy intensity. Autonomous technical change can be envisioned as a learning-by-doing process for existing technology. As experience is gained with a technology, the costs of production decline. Autonomous technical change is assumed to be the most important source of energy-related changes in the IDM. Few industrial innovations are adopted solely because of their energy consumption characteristics, but rather for a combination of factors, including process changes to improve product quality, changes made to improve productivity, or changes made in response to the competitive environment. These strategic decisions are not readily amenable to economic or engineering modeling at the current level of disaggregation in the IDM. Instead, the IDM is designed to incorporate overall changes in energy use on a more aggregate and long-term basis using the autonomous technical change parameters.

TPCs are used to derive future improvements in unit energy consumption. Future energy improvements are estimated for old (retrofit) and new processes and facilities. The energy improvements for grouped old facilities consist of gradual improvements due to energy conservation measures, retrofits of selected technologies, and the closure of older facilities, leaving the more-efficient plants in operation. The energy savings for old processes and facilities are estimated using engineering judgment regarding how much energy savings could be reasonably achieved in each industry. The estimated annual energy savings for each energy conservation measure are up to 0.5% per year.

UEC values for the state-of-the-art (SOA) and advanced technologies are also estimated. SOA technologies are the latest proven technologies that are available at the time a commitment is made to build a new plant. These values are then compared with the base year UEC values to develop an index of relative energy intensity (REI). Relative energy intensity is defined as the ratio of energy use in a new or advanced process compared with base year average energy use.

The efficiency improvement for new facilities assumes that the installation includes the SOA technologies available for that industry. A second, and at times more important, set of substantial improvements can occur when advanced technologies become available for a specific process. Often one sees a number of technologies being developed, and it is difficult to ascertain which specific technologies will be successful. Judgment is necessary as to the energy-saving potential and the likelihood for such savings to be realistically achieved. All energy improvements in the IDM are based on base year energy usage.

In addition, even SOA technologies and advanced technologies can sometimes be expected to improve after development as the process is improved, optimal residence times and temperatures are found, and better energy recovery techniques are installed. Depending on the process, these considerations are factored into the projections as slow improvements ranging from zero to a maximum of just under 1% per year.

Old facilities are assumed to be able to economically justify some retrofits and, for other reasons listed above, show slow improvements over time in their unit energy consumption. It is assumed that by 2050, old equipment (that is, the base year stock) still operating can achieve up to 50% of the energy savings of SOA technology due to retrofits and other reasons listed above. Thus, if SOA technology has an REI of 0.80, old equipment operating in the year 2050 will have an REI of 0.90. As a convenience for modeling purposes, the rate of change between the initial and final points is defined as the TPC and is used to interpolate for the intervening points.

Advanced technologies are ones that are still under development and will be available at some time in the future. Which specific technologies will be implemented is uncertain, but we can assume that at least one of these technologies or a similar technology will be successful. We also recognize that in some instances thermodynamic limits are being approached, which will prevent further significant improvements in energy savings.

Industrial energy consumption is affected by increased energy efficiency in new and old plants, the growth rate of the industry, and the retirement rate for old plants. The efficiency changes are captured in the TPCs, and the rate of growth is given by the MAM.

For all industries except process flow industries,[5] the IDM capital stock is grouped into three vintages: old, middle, and new. The old vintage consists of capital in production in the base year and is assumed to retire at a fixed rate each year. Middle vintage capital is that which is added from the base year through the year *Year*-1, where *Year* is the current projection year. New capital is added for the projection years when existing production is less than the output projected by the MAM. Capital stock added during the projection period is retired in subsequent years at the same rate as the pre-base year capital stock. Details of the calculation of UECs can be found in the description of CALCSC, which is on page 79.

Electricity TPCs for food, plastic, and miscellaneous finished goods for the process heat end use are greater than or equal to zero. This is a result of electrification, where air-source heat pumps replace some natural gas heat. These heat pumps are separate from steam generating heat pumps, which are not currently modeled. Air source heat pumps are deployed only in three industries because current research[6] shows that temperatures of other industries are often too high to allow for heat pump deployment. As a result of electrification, natural gas fueled process heat TPCs, while still less than zero, are smaller in absolute value than in previous years (in other words, decreasing more slowly).

Buildings component UEC

Buildings are estimated to account for a small percentage of allocated heat and power energy in manufacturing industries in general, but some non-energy intensive manufacturing industries have a significant percentage of building energy use.[7] Detailed projections of manufacturing sector building energy consumption are available upon request from the model contact email. Energy consumption in manufacturing buildings is assumed to grow at the average of the growth rates of employment and shipments in that industry. This assumption appears to be reasonable because lighting and heating, ventilation, and air conditioning (HVAC) are designed primarily for workers rather than machines. However, because the value of shipments tends to grow, conditioned floor space will likely also grow.

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[5] The process flow industries are cement and lime, aluminum, glass, iron and steel, and pulp and paper.

[6] McMillan (2019)

[7] U.S. Energy Information Administration, 2018 *Manufacturing Energy Consumption Survey*, (http://www.eia.gov/consumption/manufacturing/), March 2021. Note that byproduct and non-energy use of combustible fuels are excluded from the computation because they are not allocated in the MECS tables.

The IDM uses an average to account for the contrasting trends in employment and shipment growth rates.

Process and assembly component UEC

The process and assembly (PA) component is the largest share of direct energy consumption. To derive energy use estimates for the process steps, we first decompose the production process for each industry into its major steps, and then we specify the engineering and product flow relationships among the steps. We analyze process steps for each industry using one of the following two methodologies:

> **Process flow industries**. Based on the approach used in the Consolidated Impacts Modeling System (CIMS),[8] the PA component is first broken down into several unit operations using process engineering techniques. The energy consumed by each unit operation and the corresponding mass flow of material (raw materials, intermediates, or final products) through that unit operation are calculated from data in the base year. Energy consumption projections in subsequent years are based on shipments, the amount of capacity at each process step needed to meet demand, technology used in each process step, and energy consumption of each technology. This approach is applied to model those industries where the process flows can be well defined for a single broad product line by unit process step: glass, cement and lime, aluminum, iron and steel, and pulp and paper.
>
> **End-use industries**. Develop end-use estimates of energy use by generic process unit as a percentage of total energy use in the PA component. This methodology is used where the diversity of end products and unit processes is relatively large: food products, bulk chemicals, and all non-energy intensive industries.

In both methodologies, major components of energy consumption are identified by process for various energy sources, including the following:

- liquids (petroleum, natural gas liquids)
- natural gas
- coal
- purchased electricity (valued at 3,412 British thermal units per kilowatthour)
- steam
- non-fuel energy sources, such as chemical feedstocks and asphalt

The following sections present a more detailed discussion of the process steps and UEC estimates for each of the energy-intensive industries. The data tables showing the estimates are presented in Appendix B and are referenced in the text as appropriate. The process steps are module inputs with the variable name INDSTEPNAME.

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[8] Roop, Joseph M. and Chris Bataille, "Modeling Climate Change Policies in the US and Canada: A Progress Report" Presentation to the 26th USAEE/IAEE North American Conference September 27, 2006.

Electric motor stock submodule removed

We have discontinued the Electric Motor Stock Submodule. Data can no longer be disaggregated by both industry and horsepower rating, which is necessary for the model. Moreover, new motor purchases are premium efficiency motors based on meeting federal energy efficiency standards, eliminating a decision that this submodule was built to address. Motor energy consumption is now contained in the machine drive end use.

Boiler, steam, and cogeneration component

The BSC component of the IDM projects consumption of energy to meet the steam demands from conventional boilers and cogeneration. It also provides internally generated electricity to the buildings and process-and-assembly components for all industries except iron-and-steel and pulp-and-paper, for which consumption is calculated in the PA step.

The use of fuels to produce both heat and electric power in a single unit, the cogeneration element of the BSC component, represents technology implemented in industry for efficiency, which also provides a financial benefit. Some industries have been operating cogeneration plants for more than 40 years; however, due to various incentives and barriers during periods of scarce capital, varying interest rates, and changes in product demands, the popularity of cogeneration has grown and declined historically.

The modeling approach in the IDM captures both the benefits and risks in determining new capacity because a well-developed understanding of industrial steam generation is critical, especially under changing outlooks for natural gas and electricity supply and price to industrial end users.

The steam demand and byproducts from the PA and BLD components are passed to the BSC component, which allocates the steam demand to conventional boilers and to cogeneration. The allocation is based on an estimate of useful thermal energy supplied by cogeneration plants. Energy for cogeneration is subtracted from total indirect fuel use as reported in MECS to obtain conventional boiler fuel use and the associated steam. Assumed average boiler efficiency and a fuel-sharing equation are used to estimate the required energy consumption to meet the steam requirement from conventional boilers.

The boiler fuel share variable, $ShareFuel_f$, is calculated by fuel using a logistic formulation based on data from the most recent MECS. Waste and byproduct fuels are excluded from the equation because they are assumed to be consumed first. Details of the $ShareFuel_f$ calculation are given on page 81.

Cogeneration capacity, generation, fuel use, and thermal output are determined from exogenous data, and new additions are simulated, as needed, using endogenous engineering and economic evaluation. Existing cogeneration capacity and planned additions are based on data collected on Form EIA-860 and predecessor surveys. The most recent data used are for 2023, with planned additions (units under construction) through 2026.

The above input data are preprocessed outside the IDM to separate industrial cogeneration from commercial sector cogeneration, cogeneration from refineries and enhanced oil recovery operations, and off-site cogeneration. We also remove coal-fired CHP generation in the non-manufacturing industries from the data because non-manufacturing coal consumption is so minor it does not show up in SEDS. Off-site cogeneration units are primarily merchant power plants selling to the grid, often supplying relatively small amounts of thermal energy available for industrial uses. Cogeneration capacity is disaggregated by region and industry, and the four IDM industries that use the most cogeneration are bulk chemicals, paper, food, and iron and steel. Refining is also a major cogeneration industry, but it is not modeled in the IDM. The iron-and-steel and pulp-and-paper submodules do not use this general module component that applies to all other industry submodules, but they have specific cogeneration modeling.

The modeling of unplanned cogeneration begins with model year 2023, under the assumption that planned units under construction cover only some of the likely additions through 2023. In addition, we assume that any existing cogeneration capacity will remain in service throughout the projection period, or equivalently, will be refurbished or replaced with like units of equal capacity. The modeling of unplanned capacity additions is done for two capacity types: biomass-fueled and fossil-fueled. We assume biomass cogeneration is added as increments of biomass waste products are produced, but the iron-and-steel and pulp-and-paper submodules have specific cogeneration code. The amount of biomass cogeneration added is equal to the quantity of new biomass available (in British thermal units), divided by the total heat rate assumed from biomass steam turbine cogeneration.

Unplanned additions to fossil-fueled cogeneration are projected based on an economic assessment of capacity that could be added to generate the industrial steam requirements that are not already met by existing cogeneration. The driving assumption is that the technical potential for traditional cogeneration is primarily based on supplying thermal requirements. We assume that cogenerated electricity can be used to reduce purchased electricity, or it can be sold to the grid. For simplicity, the approach adopted is generic, and the user sets the characteristics of the cogeneration plants. The fuel used is assumed to be natural gas, based on a study performed for EIA.[9]

The steps to the approach are:

- Assess the steam requirements that could be met by new cogeneration plants
- Subtract steam met by existing cogeneration units, given total steam load for the industry in each region from the process-assembly and buildings components
- Classify non-cogenerated steam uses into six size ranges, or load segments, based on an exogenous data set[10] providing the boiler size distribution for each industry and assuming that steam loads are distributed in the same proportions as boiler capacity. The average boiler size (in terms of fuel input per hour) in each load segment is also included in the same exogenous data set, which is used to size the prototypical cogeneration system in each load segment. The prototype cogeneration system sizing is based on the steam generated by the average-sized boiler in each load segment.
- Establish the average hourly steam load in each segment from the aggregate steam load to determine total technical potential for cogeneration (discussed further below).

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[9] Leidos, *Distributed Generation, Battery Storage, and Combined Heat and Power System Characteristic and Costs in the Builds and Industrial Sectors*, report prepared for the Office of Energy Consumption and Efficiency Analysis, U.S. Energy Information Administration, Washington, DC, March 2024. https://www.eia.gov/analysis/studies/buildings/dg_storage_chp/.
[10] Energy and Environmental Analysis, Inc., *Characterization of the U.S. Industrial Commercial Boiler Population*, submitted to Oak Ridge National Laboratory, May 2005.

- Evaluate a natural gas turbine system prototype for each size range.
- Establish a candidate cogeneration system for each load segment with thermal output that matches the steam output of the average-sized boiler in each load segment, with user-supplied characteristics for eight cogeneration systems for either the Reference case or the High Technology case. The characteristics used in the calculation include the following:
- Net electric generation capacity in kilowatts (kW)
- Total installed cost, in 2022 dollars per kilowatthour (kWh)
- System capacity factor
- Total fuel use per kWh
- Fraction of input energy converted to useful heat and power
- Determine the investment payback period needed to recover the prototypical cogeneration investment for each of the system sizes.
- Assess market penetration based on the discounted payback and the payback acceptance curve.
- Determine the maximum technical potential for cogeneration under the assumption that all non-cogeneration steam for each load segment is converted to cogeneration. This process assumes that the technical potential is based on 1) sizing systems, on average, to meet the average hourly steam load in each load segment and 2) the power-steam ratio of the prototype cogeneration system.
- Determine economic potential and market penetration of the candidate cogeneration systems.
- Estimate the fraction of total technical potential that is considered economical, given the payback for the prototype system evaluated. Calculating this estimation requires starting with an assumption about the distribution of required investment payback periods called the payback acceptance curve. The shorter the payback, the greater the fraction of firms that would be willing to invest. It can also capture the effect that market barriers have in discouraging cogeneration investment.
- Estimate the amount of capacity that would be added in the current model year, given the total economic potential for cogeneration. The annual capacity additions are estimated assuming linear market penetration over a 20-year period. Thus, 5% of the economic potential is adopted each year. Since the amount of technical and economic potential is reevaluated in each model year as economic conditions and steam output change, the annual additions will vary. However, over the 25-year projection period, if economic conditions remained constant and steam loads did not increase, the cumulative capacity additions would be equal to the total economic potential determined in the first model projection year.

The analysis considers the annual cash flow from the investment to be equal to the value of the cogenerated electricity, minus the cost of the incremental fuel required to generate it that is discounted using the 10-year Treasury bill rate as projected in the MAM plus a risk premium. For this purpose, the annual cost of fuel (natural gas) and the value of the electricity are based on the prices in effect in the model year in which the evaluation is conducted. The module assumes that the electricity is valued at the average industrial electricity price in the region, net of standby charges that would be incurred after installing cogeneration. The standby charges were assumed to be some fraction of the industrial electricity rate (usually 10%).

For natural gas, the price of firm-contract natural gas was assumed to apply. Because the broad modeling needs in the IDM require a simplified representation, non-fuel operating costs are not included. The costs are small relative to fuel costs and can be difficult to quantify with aggregate, load segment methodology being used as well. The payback is determined by dividing the investment by the average annual cash flow.

Benchmarking

The IDM energy demand projections are benchmarked to historical data values presented in EIA's *Monthly Energy Review.*[11] The national-level values reported here were allocated to the census divisions using the 2023 *State Energy Data System* (SEDS).[12] The benchmark factors are based on the ratio of the SEDS value of consumption for each fuel to the consumption calculated by the module at the census region level. The SEDS covers historical data. After the last historical data year, the IDM results are benchmarked to the *Short-Term Energy Outlook* (STEO). We apply the STEO benchmark at the national level and generally extend it a few years past the last historical year. Past the STEO forecast years, the IDM retains a composite of benchmark factors (SEDS and STEO) and applies these composite benchmark factors through the projection period, with the STEO benchmark's relative weight fading over time in favor of the SEDS benchmark. The composite benchmark factors are viewed as a correction for under- or over-coverage of energy consumption produced by the module.

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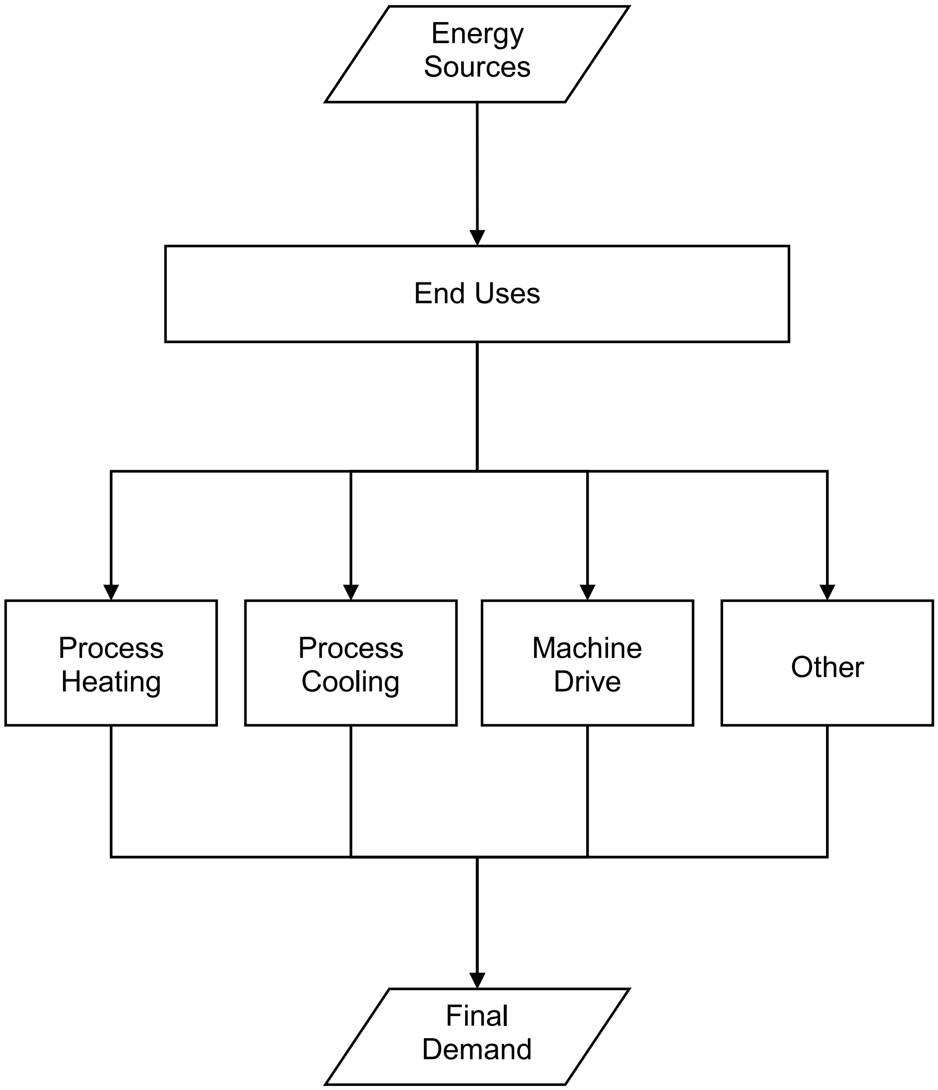
[11] U.S. Energy Information Administration, *Monthly Energy Review, December 2024*, http://www.eia.gov/totalenergy/data/monthly/archive/00351309.pdf.

[12] U.S. Energy Information Administration, *State Energy Data System,* Consumption Data in Btu, 1960–2019, https://www.eia.gov/state/seds/sep_use/total/csv/use_all_btu.csv

Energy-intensive manufacturing industries

Food products (NAICS 311): end-use method

Figure 3. Food industry end uses in the Industrial Demand Module

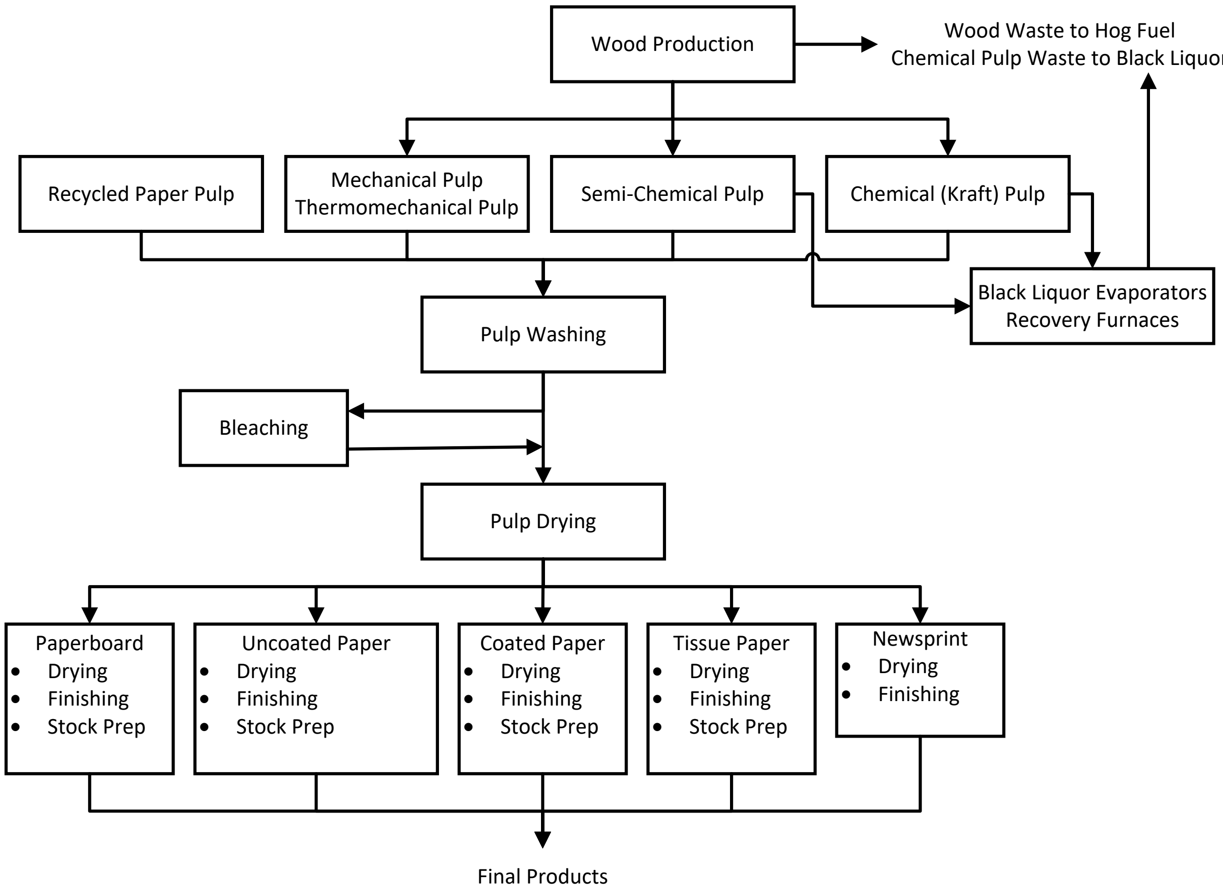


Source: U.S. Energy Information Administration

The food industry is modeled by the four subsector industries: grain and oilseed milling (NAICS 3112), dairy product manufacturing (NACIS 3115), animal slaughter and processing (NAICS 3116), and other food products. Energy use in the food products industries for the PA component was estimated for each of four major end-use categories of process heating, process cooling and refrigeration, machine drive, and all other uses. Figure 3 portrays the PA component's end-use energy flow for the food products industry.

Paper products (NAICS 322): process flowsheet method

Figure 4. Paper manufacturing industry process flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

The paper and allied products industry's principal processes involve converting wood fiber to pulp, pulp to paper and paperboard, and then paper and paperboard to consumer products (generally targeted at the domestic marketplace). The industry produces a full line of paper and paperboard products, as well as dried pulp, which is sold as a commodity product to domestic and international paper and paperboard manufacturers.

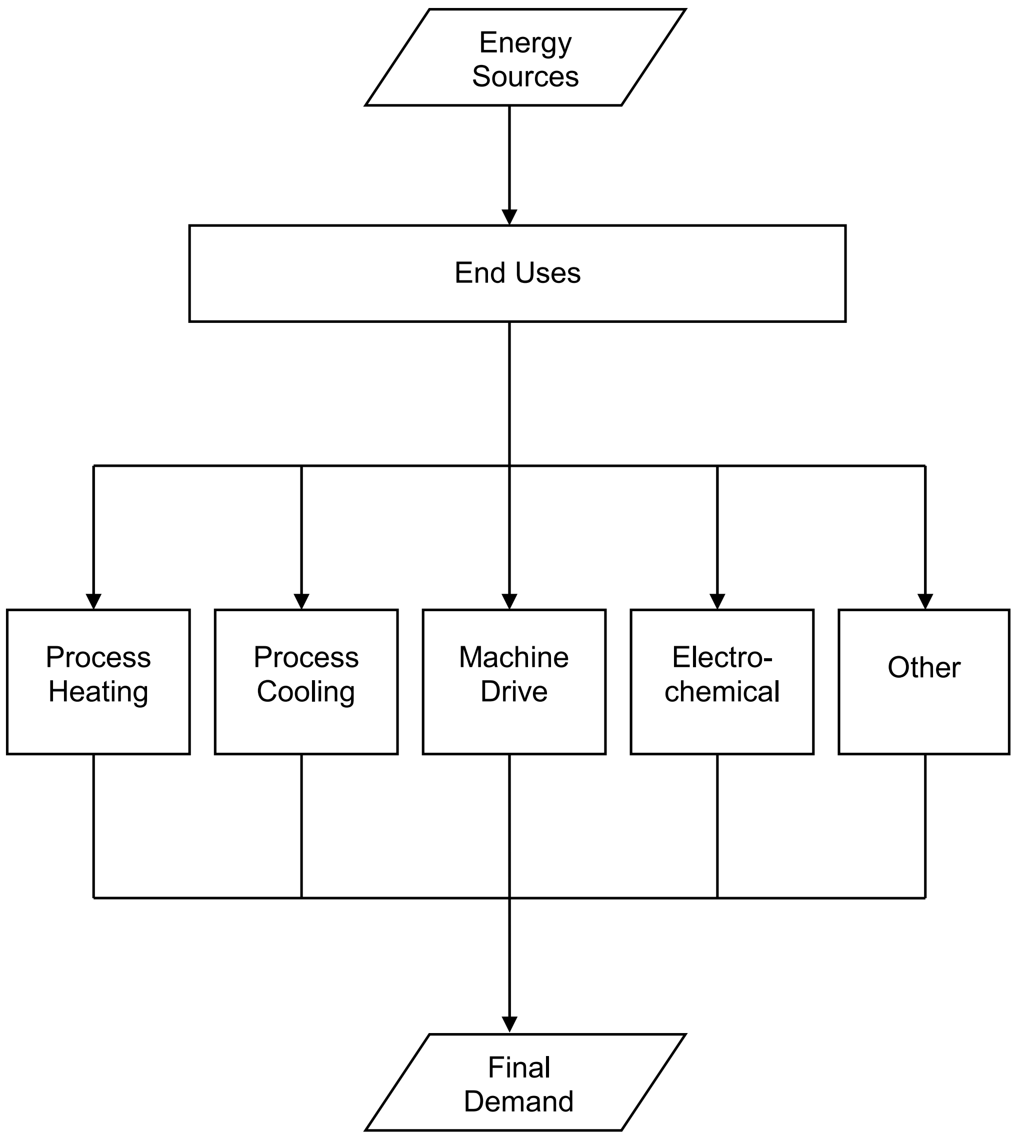
Figure 4 illustrates the major process steps for all pulp and paper manufacturing that are process steps (denoted by *isx*) in the module. Almost all process steps have multiple technologies. The wood preparation step is removing the bark and chipping the whole tree into small pieces. Pulping is the process by which the fibrous cellulose in the wood is removed from the surrounding lignin. Pulping can be conducted with a chemical process (for example, Kraft, semi-chemical) or a mechanical process. The pulping step also includes processes such as drying, liquor evaporation, effluent treatment, and miscellaneous auxiliaries. Bleaching is required to produce white paper stock. The pulp and paper industry has significant recycling. Black liquor that is used as fuel in combined heat and power (CHP) and boilers is produced from chemical process step outputs to black liquor evaporators and recovery furnaces. Wood preparation produces hog fuel that is also used as fuel in CHP and boilers.

Paper and paperboard-making takes the pulp from the preceding processes and makes the final paper and paperboard products. The manufacturing operations after pulp production are similar for all of the paper end products even though their processes differ. The processes in the papermaking step include converting and packaging, coating and re-drying, effluent treatment, and other miscellaneous processes associated with the process steps of drying, finishing, and stock preparation.

The paper products are associated with the process steps of paperboard, uncoated paper, coated paper, tissue paper, and newsprint. The major paperboard products include Kraft paperboard, corrugating medium, and recycled paperboard. Future additions to pulping capacity are assumed to reflect a slight relative increase in waste pulping via increased use of market pulp. This assumption reflects recent trends in additional imports of market pulp.

Bulk chemical industry (parts of NAICS 325): end-use method

Figure 5. Bulk chemical end uses in the Industrial Demand Module



Source: U.S. Energy Information Administration

The bulk chemical sector is very complex. The modeled subsector industries are inorganic chemicals, organic chemicals, resins and synthetics, and agricultural chemicals. Their NAICS codes are listed in Table 2. These chemical industries are aggregated to the bulk chemicals output while the other chemicals industries are part of the light chemicals industry. Bulk chemicals is a major energy feedstock user and a major producer of combined heat and power.

Table 3. Chemical products in the bulk chemicals industry submodule in the Industrial Demand Module

Organic chemicals	Inorganic chemicals	Resins	Agricultural chemicals
Ethylene	Acetylene	Polyvinyl chloride	Ammonia
Propylene	Chlorine	Polyethylene	Phosphoric acid
Butadiene	Oxygen	Polystyrene	Other agricultural chemicals
Acetic acid	Sulfuric acid	Styrene-butadiene	
Acrylonitrile	Hydrogen	Rubber	
Ethylbenzene	Other inorganic chemicals	Vinyl chloride	
Ethylene dichloride		Other resins	
Ethylene glycol			
Ethylene oxide			
Formaldehyde			
Methanol			
Styrene			
Vinyl acetate			
Ethanol			
On-purpose propylene (and byproduct ethylene)			
Other organic chemicals			

Source: U.S. Energy Information Administration, based on U.S. Census Bureau

Note: Acetylene is an organic molecule, but the existing NAICS codes classify it as inorganic.

The bulk chemical industry's energy consumption patterns are equally complex; demands for heat, steam, electricity, and energy feedstocks are driven by the demand for production of numerous chemical products, as well as the processes and technologies involved in making these products. Chemicals are aggregated into the four categories as defined in Table 2. Modeling of energy consumption within these groups is accomplished by the TPC method used for most other industries as described in Figure 4. A limited feedstock selection algorithm is included as well (see below).

The delineation of feedstock demand applies only to the PA component of the bulk chemical energy consumption projections. The PA component also estimates energy consumption for direct process heating, cooling and refrigeration, machine drive, electro-chemical processes, and other uses. The BSC and BLD components remain the same for this industry as in other modules. Thus, steam demand projections are passed from the PA component to the BSC component. The BSC component then calculates fuel consumption to generate the steam. In addition, as in the other modules, the BLD component projects energy consumption for this industry's use of its facilities for space heating, space cooling, and lighting.

The feedstock UECs are initialized from the base year MECS data the same way as the fuel components, but unlike most fuels, the feedstock TPC rates of change are set to zero. In other words, the UECs for feedstocks are assumed not to improve over time. This assumption is based on the inherent stoichiometric relationship between basic chemical products, such as ethylene, propylene, and ammonia, and their feedstocks such as natural gas, HGLs, and naphtha. In the short term (history through one year after the last STEO year), EIA analysts estimate some feedstock values based on capacity and industry expectations. These values are read into the IDM via the READ_FEEDSTOCK subroutine (see below).

We estimate natural gas feedstock in the short term using a combination of EIA data (from MECS and the *Monthly Energy Review*), announced methanol and fertilizer projects, and analyst judgement. We apply this method of estimation through one year after the last STEO year (in other words, two years after the year of the AEO release). After that, we use the end-use method to determine natural gas feedstock consumption, whose intensity is assumed to be constant throughout the projection period.

The IDM calculates the total feedstock demand for all HGLs (ethane, propane, propylene, butanes, and natural gasoline) and for naphtha using the end-use method described above. HGL alkanes and naphtha are able to substitute for each other to some degree in the production of olefins, so the IDM uses an algorithm to calculate the relative shares of the total feedstock demand met by each HGL and by naphtha.

Hydrogen has been added to NEMS as an explicit feedstock and fuel as of AEO2025. Previously, industrial hydrogen consumption was implicitly accounted for in the natural gas feedstock consumed in the bulk chemicals industry. For AEO2025, we now assume a portion of that natural gas feedstock consumption (NAICS 325199 in MECS) is used for production of methanol and assume the rest of the natural gas feedstock is used to generate hydrogen. Now, instead of modeling the natural gas used to generate hydrogen in IDM, we model the industrial demand for hydrogen directly.

On-purpose hydrogen generation and supply and the associated energy consumption is now modeled in the new Hydrogen Market Module (HMM). HMM energy consumption (both fuel and feedstock) is included in the industrial total in NEMS tables unless explicitly specified, much in the same way refining is part of industrial consumption but is modeled in LFMM. (See the HMM documentation for more details on hydrogen generation.) The sum of IDM, LFMM, and HMM primary consumption (defined as consumption excluding hydrogen, to avoid double-counting of energy) still adheres to SEDS and STEO benchmarking in the same manner that the sum of IDM and LFMM primary consumption did in AEOs prior to AEO2025.

HMM does not run in the IDM base year in AEO2025. We estimated base year hydrogen supply (Table 4) and consumption (Table 5) using a combination of MECS data, U.S. Geological Survey data, and a steam methane reformer production factor of 0.1573 million British thermal units (MMBtu) feedstock natural gas per kilogram hydrogen[13]. We use the baseline hydrogen consumption and supply as input to the IDM. The subroutine Read_H2 reads the base year hydrogen supply and demand by industry and census region into IDM from the input file ind_H2.csv. The input file also includes refining supply of hydrogen in the base IDM year by census division (based on data from the *Petroleum Supply Annual*[14]).

[13] National Renewable Energy Laboratory, *H2A-Lite: Hydrogen Analysis Lite Production Model*, (Golden, Colorado, 2018)
[14] U.S. Energy Information Administration, *Petroleum Supply Annual*, (Washington, DC, January 2024).

Table 4. Base year hydrogen supply by bulk chemical subsector

trillion British thermal units

Bulk chemicals subsectors	Region 1	Region 2	Region 3	Region 4	U.S. total
Industrial gases	0	5	116	15	136
Other inorganics	0	1	38	1	40
Petrochemicals	0	0	3	0	3
Other organics	0	0	60	0	60
Resins	0	0	34	0	34
Agricultural chemicals	0	131	245	9	385

Source: U.S. Energy Information Administration

Table 5. Base year hydrogen consumption by bulk chemical subsector

trillion British thermal units

Bulk chemicals subsectors	Region 1	Region 2	Region 3	Region 4	U.S. total
Industrial gases	0	0	0	0	0
Other inorganics	0	1	38	1	40
Petrochemicals	0	0	3	0	3
Other organics	0	0	60	0	60
Resins	0	0	34	0	34
Agricultural chemicals	0	160	245	9	414

Source: U.S. Energy Information Administration

We grow the bulk chemical hydrogen demand based on regional macroeconomic shipments in years after the base year. Bulk chemicals is the only industry explicitly assumed to consume hydrogen in the base year, though the IDM's iron and steel industry submodule has a technology option that uses hydrogen feedstock and can deploy in later years.

Although HMM models on-purpose hydrogen production and price, IDM models byproduct hydrogen production. The base year byproduct hydrogen production is the difference between hydrogen demand in all sectors that can consume hydrogen (currently industrial, refining, transportation, and power generation) in the IDM base year and the read-in hydrogen supply from industrial and refining. We assume the difference in supply and demand is met with byproduct hydrogen from the chemical cracking of ethane, propane, and naphtha. Byproduct hydrogen production grows as a function of the consumption of ethane, propane, and naphtha feedstocks, weighted by the cracking yields in Table 6 for ethane and naphtha, and a cracking yield of 0.0296 trillion Btu (TBtu) hydrogen per TBtu propane (based on an assumed stoichiometric 1 mole of hydrogen produced per mole of propane cracked). Equation 1 shows the calculation of byproduct hydrogen in years following the IDM base year:

$$BYPRDH2IN_{d,y} = BYPRDH2IN_{d,y-1} * \left(\frac{\sum_i c_i Q_{i,d,y}}{\sum_i c_i Q_{i,d,y-1}}\right) \tag{1}$$

where

$BYPRDH2IN_{d,y}$ = TBtu of byproduct hydrogen produced in census division d and year y;

$Q_{i,d,y}$ = industrial consumption of feedstock i (ethane, propane, or naphtha) in census division d and year y; and,

c_i = the cracking yield of product i in TBtu hydrogen per TBtu feedstock.

The chemicals industry produces olefins from HGLs and naphtha through a chemical process known as cracking. We assume all new cracking capacity in the United States is light-feedstock-based (that is, it cracks HGLs and not naphtha). However, under certain price conditions, some amount of existing light feedstock cracking capacity is allowed to switch over to cracking heavy feedstock. This ability represents how certain facilities can switch between cracking HGLs and heavy feedstock.

The IDM's feedstock switching algorithm begins the year after the read-in feedstock data ends. Light-heavy feedstock switching is represented in the module as switching between using ethane (light) and naphtha (heavy) feedstocks for ethylene (the desired olefin) production. Ethane-naphtha switching is a function of ethylene demand (derived from linear regressions of third-party historical ethylene consumption data[15] and the MAM's shipments of resins, synthetic rubber, and fibers, as well as the calculated plastic recycle rate described below), the relative price of each feedstock and coproduct (derived from linear regressions of historical chemical price data and the West Texas Intermediate price), and the chemical cracking efficiencies of each feedstock[16] (shown in Table 7). The IDM calculates the feedstock cost of ethane needed to produce one metric ton of ethylene, and it subtracts the value of the side products produced from cracking one metric ton of ethane to get the net feedstock cost of producing ethylene from ethane. The same value is calculated for naphtha by subtracting the value of the side products produced from cracking one metric ton of ethylene from the cost of the naphtha used to produce one metric ton of ethylene. The net costs of each feedstock are compared against each other, and the feedstock with the lower net cost is considered more economical. We assume the differences in process and in capital costs are negligible.

Table 6. Chemical mass yields for cracking ethane and naphtha in the Industrial Demand Module, metric tons of product per metric ton of feedstock

Product	Ethane feedstock yield	Naphtha feedstock yield
hydrogen	0.0591	0.0097
methane	0.0704	0.1694
ethylene	0.8091	0.3867
propylene	0.0194	0.1547
butadiene	0.0178	0.0476
butylenes or butanes	0.0081	0.0507
benzene	0.0081	0.0437
toluene	0.0008	0.0166
xylene	0.0000	0.0224
other aromatics	0.0073	0.0735
fuel oil	0.0000	0.0251

Source: U.S. Energy Information Administration, based on *Ethylene Product Stewardship Manual*, December 2004

[15] American Chemistry Council, Business of Chemistry 2020 (Annual Data), 2020.

[16] American Chemistry Council, *Ethylene Product Stewardship Manual*, December 2004.

The amount of capacity that can switch between cracking ethane and naphtha is based on a few assumptions. First, we assume the baseline naphtha feedstock consumption is constant during the period the chemical feedstock switching algorithm runs, equal to 90% of 2019 naphtha feedstock consumption, or about 550 trillion British thermal units (TBtu) of naphtha. This assumption represents older cracking facilities that can only crack naphtha and cannot be converted to crack HGLs. All of this capacity is in the West South Central Census Division. We also assume some existing cracking capacity can quickly switch between cracking ethane and naphtha, depending on the relative net feedstock costs. This baseline flexible capacity is equal to 2011 ethylene produced from naphtha minus the ethylene produced from the nonflexible (naphtha-only) capacity, or about 2.6 million metric tons of ethylene. Flexible capacity is also all located in the West South Central Division and starts out cracking only ethane. In a given year where either ethane or naphtha is more economical, 50% of existing flexible capacity (after capacity additions) will change to the most economical feedstock (if that feedstock is not already being used in 100% of the flexible capacity).

Some existing capacity, which initially cracks only ethane, can convert to flexible capacity over time. Given a sustained price signal where the net feedstock costs (after accounting for the value of side products) for ethane are higher than the net feedstock costs for naphtha for three consecutive years, some of this convertible capacity will switch over to flexible capacity after a construction period of two more years. This shift represents ethane cracking facilities that need substantial investment to be able to crack naphtha (but, once converted, can quickly switch between feedstocks). The maximum amount of ethane capacity that can be converted to flexible capacity is equal to the 2004 ethylene produced from naphtha minus the 2011 ethylene produced from naphtha, or about 5.5 million metric tons of ethylene. This capacity can be converted to flexible capacity in increments of 1.1 million metric tons of ethylene capacity. We assume any new ethane cracking capacity built during the projection period will not be convertible to flexible capacity.

The difference between total feedstock demand and feedstock demand for the production of ethylene is met by the remaining HGLs: propane, propylene, butanes, and natural gasoline. Propylene consumption is constant at 302,000 barrels per day, while the remaining HGLs are assumed to remain a constant fraction of the remaining HGL demand (that is, total HGL demand minus demand met by ethane, naphtha, and propylene), based off relative demand in the last year of read-in data.

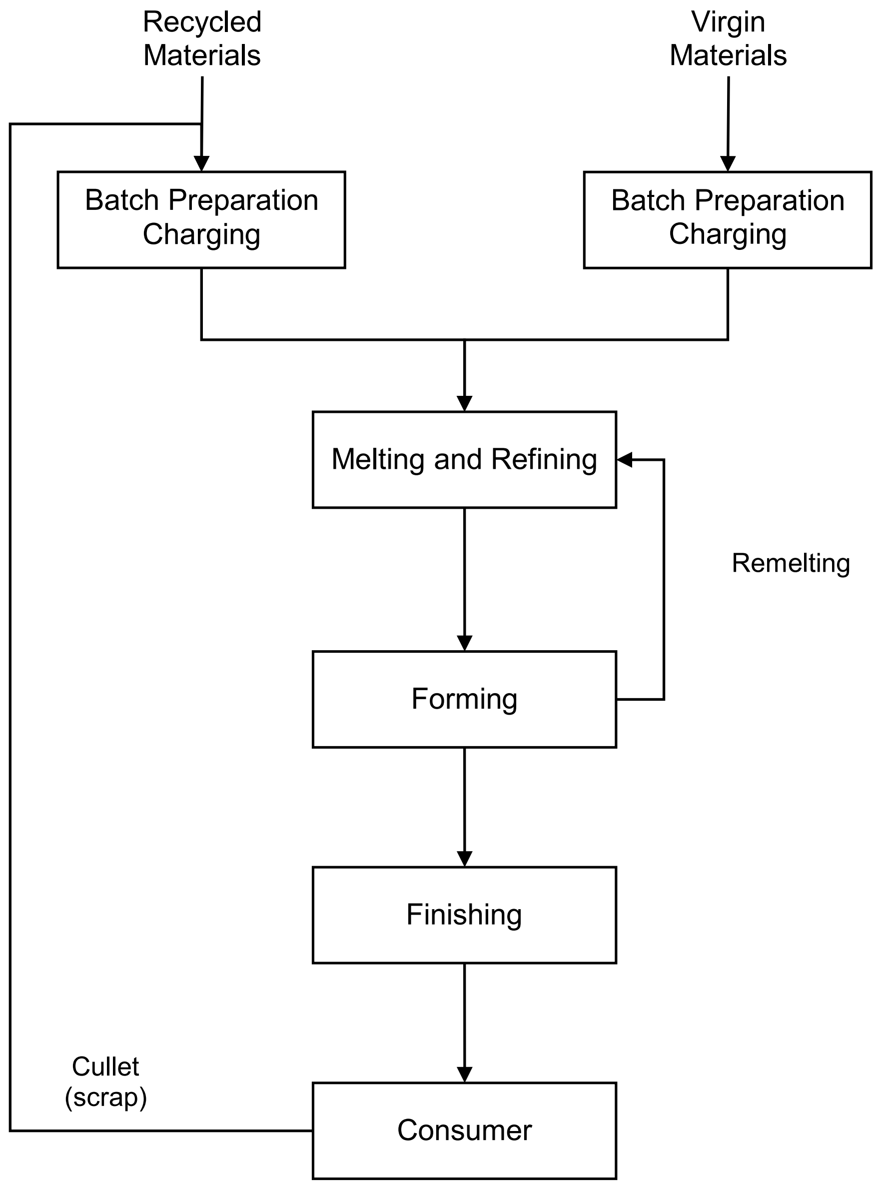
The demand for ethane may exceed the amount of ethane produced in the United States. We assume that when this shortfall happens, instead of importing ethane, demand for domestically produced propane and butanes meets the excess ethane demand at a ratio of 83% propane and 17% butanes (on an energy basis). We assume the shift between ethane and propane/butanes is approximately equivalent on an energy basis; propane and butane are both light feedstocks, similar enough to ethane that we use the same cracking efficiency. (Switching between lighter ethane and heavier naphtha requires accounting for very different cracking efficiencies.)

We also calculate a chemical recycle rate that reduces the total ethylene demand as well as total HGL demand (variable HGL_recycle_rate). This rate starts out at an estimated base value of 5% in 2018, which represents the approximate offset in HGL demand resulting from the recycling of plastics. In other words, there is a 5% reduction in HGL demand as a result of plastic recycling that is implicitly included in the base year feedstock data. Over time, this rate changes as a function of ethane price using a linear regression between historical ethane price and HGL demand reduction resulting from plastic recycling.

Finally, for AEO2025 (all cases), a hard-coding device was used to ensure that the consumption of HGL feedstock did not decline over the first 10 years or so of the projection. Modeling HGL feedstock consumption is extraordinarily difficult because the historical growth of energy-intensive petrochemicals production like ethylene does not comport with the actual value of organic chemical shipments. This dissonance creates chaos in modeling HGL feedstock because it is the *value* (as opposed to the quantity) of organic chemical shipments that drives feedstock consumption. In the past 10 years of history and in the first 5 years of the projection when organic shipments decrease sharply, HGL consumption rises due to increased production of low value ethylene. Because it is unlikely that ethylene production will drop in the near future, HGL feedstock consumption was hard-wired for AEO2025 to prevent it from dropping below its base level in the last historical year, 2023.

Glass and glass products industry (NAICS 3272): Process flowsheet method

Figure 6. Glass industry process flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

An energy use profile has been developed for the whole glass and glass products industry, NAICS 3272. This industry definition includes glass products made from purchased glass. The glass-making process contains four process steps: batch preparation, melting and refining, forming, and finishing. Figure 6 provides an overview of the process steps involved in the glass and glass products industry. Although cullet (scrap) and virgin materials are shown separately to account for the different energy requirements for cullet and virgin material melting, glass makers generally mix cullet with the virgin material.

The fuels consumed are predominantly for direct fuel use because this industry has very little steam demand. Direct fuel use is mainly in furnaces for melting.

We model the energy demand reduction resulting from the use of recycled cullet as input to the container glass subsector. We assume 30% of cullet going into the container glass industry is recycled cullet in the base year. That share grows linearly to an assumed 75% share recycled cullet in 2050. Container furnace energy consumption is reduced by about 2.5% for each 10% of input that is recycled cullet[17], so we apply this reduction factor uniformly to each fuel consumed for container glass production.

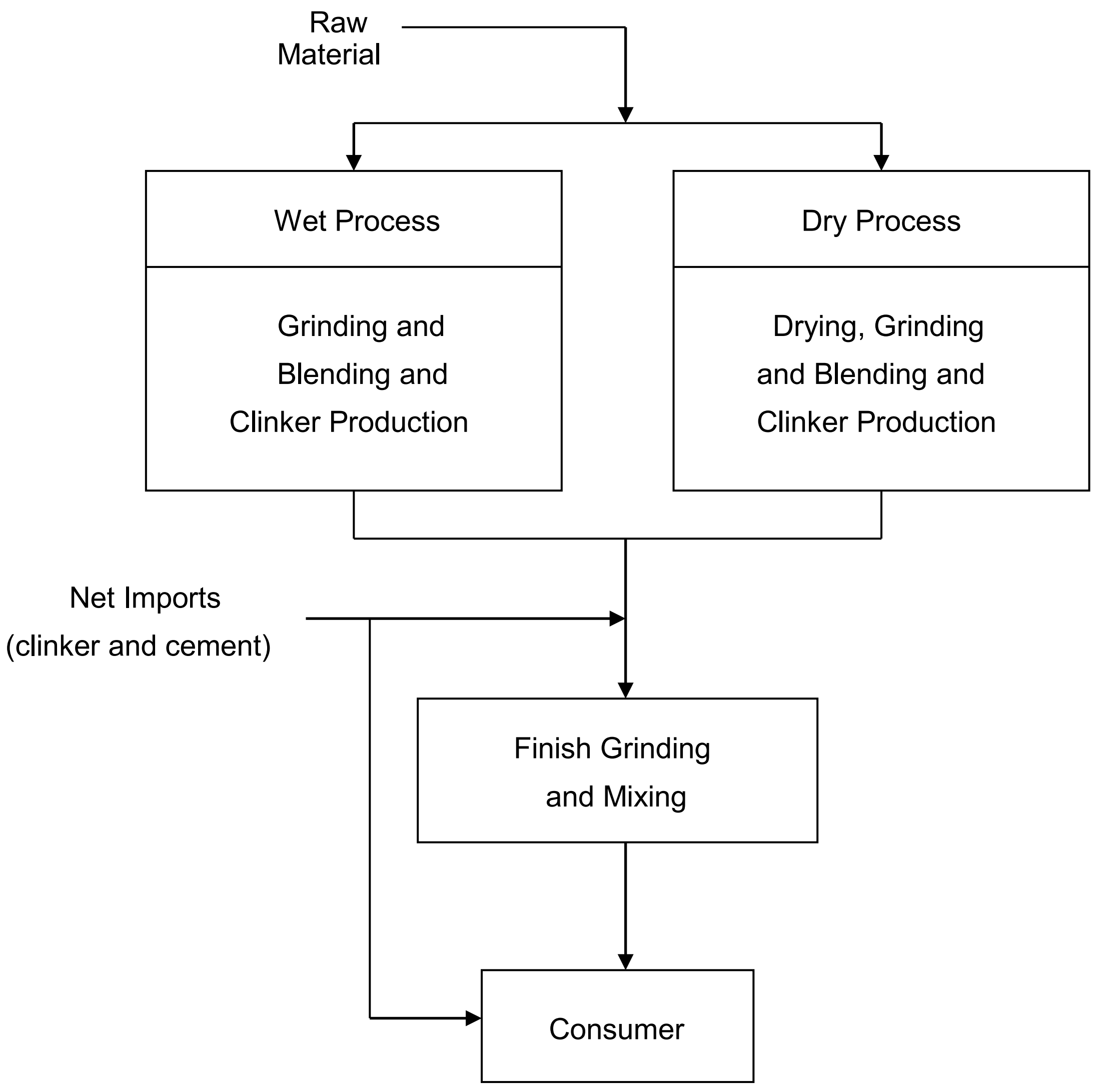
We also model non-energy-related process emissions in the glass industry, representing CO_2 released from virgin cullet when it is melted. We use an emissions factor of 0.155 metric tons CO_2 per metric ton of virgin glass. The emissions factor is based on total 2018 emissions from the U.S. glass industry[18], our input parameter for the total metric tons of all glass produced in 2018, and our assumed baseline recycle rate of 30% for the container glass. Process emissions in a given year are calculated by applying the emissions factor to the metric tons of each type of glass produced minus the tons of container glass that are produced from recycled cullet.

[17] Rue, David, 2018, *Cullet Supply Issues and Technologies*, Glass Manufacturing Industry Council.

[18] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2022*, April 18, 2024, https://www.epa.gov/system/files/documents/2024-04/us-ghg-inventory-2024-main-text_04-18-2024.pdf.

Cement and lime industries (NAICS 32731, 32741): process flowsheet method

Figure 7. Cement industry process flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

The cement (NAICS 32731) and lime (NAICS 32741) industries' energy consumption are reported together in NEMS. Both cement and lime are represented using a process flow submodule that derives energy use from specific technologies, rather than engineering judgment of general energy use.

The cement industry uses raw materials from non-manufacturing quarrying and mining industries. These materials are sent through crushing and grinding mills and are converted to clinker in the clinker-producing step. This clinker is then further ground to produce cement. The industry produces cement by two major processes: the wet process and the dry process. The dry process is less energy-intensive than the wet process, and so the dry process has steadily gained favor in cement production. As a result, it is assumed in the module that all new plants will be based on the dry process. Figure 7 provides an overview of the process steps involved in the cement industry.

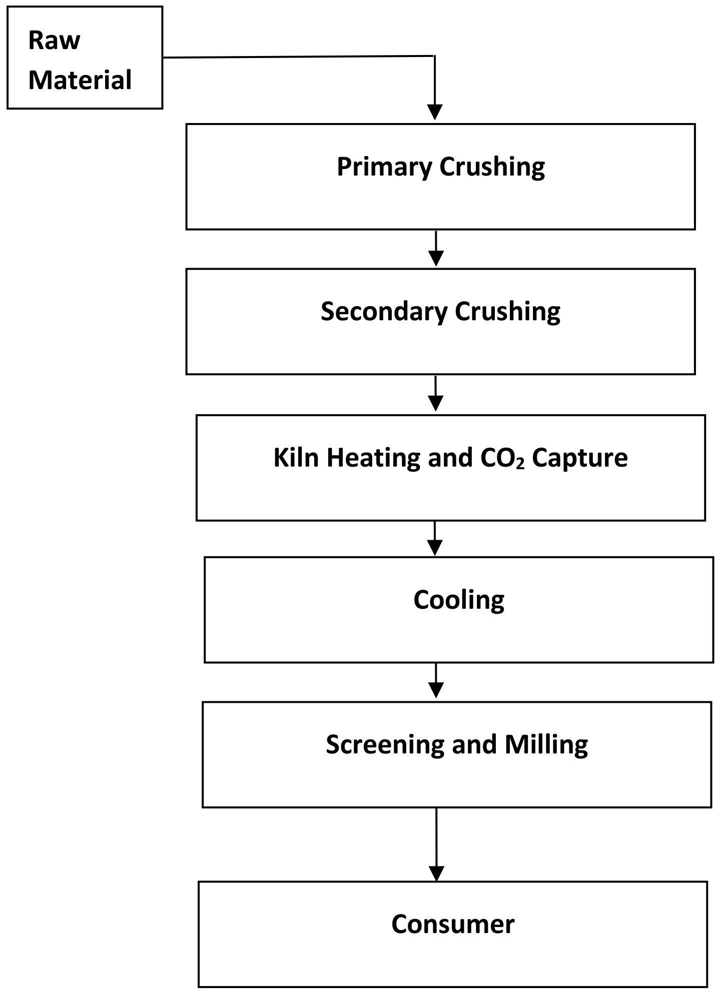
For AEO2025, carbon capture and sequestration (CCS) is modeled as retrofit equipment on existing (as of 2024) cement plant capacity. The economic motivation for these retrofits is the 45Q tax credit which was expanded in the Inflation Reduction Act (IRA). Full formulation and modeling details of the cement CCS submodule is described in Appendix C. Carbon Capture and Sequestration in Cement

All energy associated with operating the cement industry retrofit CCS equipment is accounted for as cement industry energy consumption (specifically, natural gas and purchased electricity employed to operate CCS equipment). In addition, although the new CCATS (Carbon Capture, Allocation, Transportation and Sequestration) module in NEMS is responsible for computing the purchased electricity associated with transporting CO_2 via pipelines from the capture source to the sequestration site, the IDM reports this energy use under its other mining industry in AEO2025. Similarly, electricity used to run CCS equipment for natural gas processers is also reported in IDM's "other mining" industry but it is modeled in the Hydrocarbon Supply Module (HSM).

Since cement is the primary binding ingredient in concrete mixtures, it is used in virtually all types of construction. As a result, the U.S. demand for cement is highly sensitive to the level of construction activity, which is projected in the MAM and used as an input for IDM.

Lime has a number of uses. The majority of lime is used in metallurgical applications—primarily iron and steel—and flue gas desulfurization. Other major uses are water treatment, construction (including cement), and pulp and paper. Lime is used chemically to make the properties of a product more desirable, such as by lowering acidity, as part of a chemical reaction (such as in cement), and to remove impurities (such as in metallurgical applications or flue gas desulfurization).

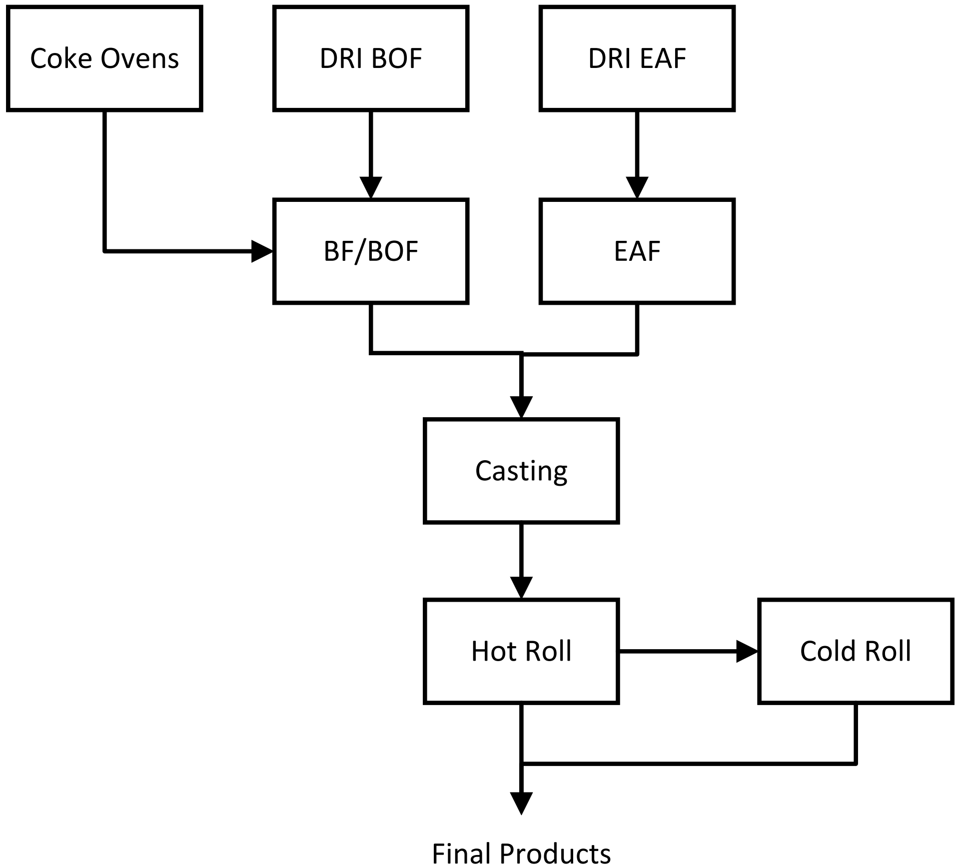
Figure 8. Lime process flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

Iron and steel industry: (NAICS 3311, 3312, 324199): process flowsheet method

Figure 9. Iron and steel industry process flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

Figure 9 shows the major process steps for the iron and steel industry. Almost all process steps have multiple technologies that are addressed in the detailed iron and steel documentation. The process steps are coke production, ironmaking in direct reduced iron for basic oxygen furnaces (DRI BOF), direct reduced iron for electric arc furnaces (DRI EAF), blast furnace/basic oxygen furnace (BF/BOF), steelmaking in BF/BOF and EAF, and steel product production via casting, hot rolling, and cold rolling. An agglomeration step is excluded from the IDM iron and steel submodule because it is considered part of mining. Iron ore and coal are the basic raw materials that are used to produce iron.

Steel manufacturing plants can be classified as integrated or non-integrated. The classification is based on the number of the major process steps that are performed in the facility. Integrated plants perform all the process steps, whereas non-integrated plants, in general, perform only the last three steps.

Iron produced in a blast furnace is charged into a BOF to produce raw steel. Coke ovens and blast furnaces also produce a significant amount of byproduct fuels, which are used throughout the steel plant. EAFs produce raw steel from scrap (recycled materials), sometimes supplemented with direct reduced iron or hot briquetted iron.

The raw steel is cast into blooms, billets, or slabs using continuous casting. Some cast steel is sold directly (for example, forging-grade billets). The majority is further processed by hot rolling into various mill products. Some of these products are sold as hot-rolled mill products, while others are further processed by cold rolling to impart surface finish or other desirable properties.

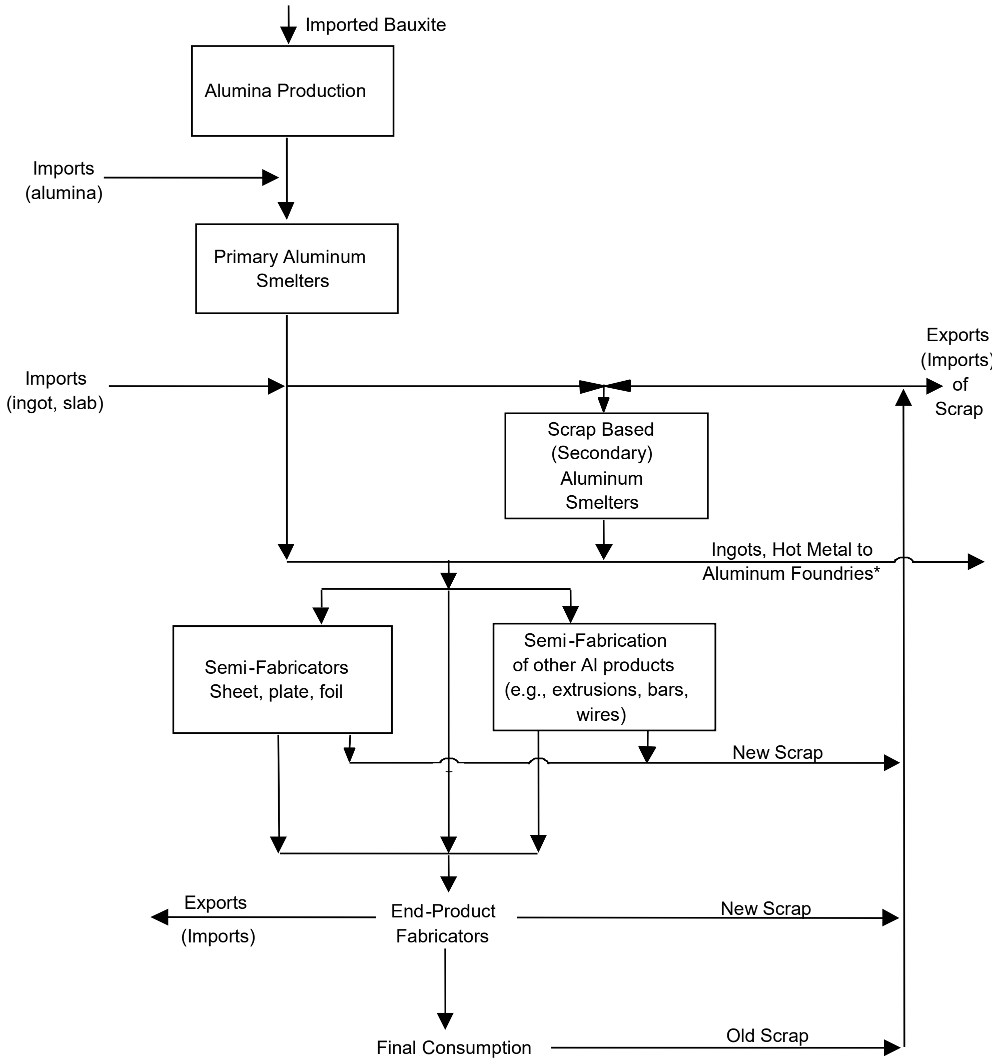
Alumina and aluminum industry (NAICS 3313): process flowsheet method

The U.S. aluminum industry consists of two major sectors: the primary aluminum sector, which uses alumina as raw material, and the secondary sector, which uses collected aluminum scrap as a raw material. The primary and secondary aluminum industries have historically catered to different markets, but these distinctions are fading. Traditionally, the primary industry bought little scrap and supplied wrought products, including sheet, plate, and foil. The secondary industry was scrap-based and historically supplied foundries that produce die, permanent mold, and sand castings. More recently, secondary aluminum smelters have started supplying wrought (sheet) stock. In addition, in the past decade, primary producers have increasingly used recycled aluminum, especially from beverage cans.

Figure 10 provides an overview of the process steps involved in the aluminum industry. The energy use analysis accounts for energy used in NAICS 3313, which includes the following:

- alumina refining and primary aluminum production (NAICS 331313)
- secondary smelting and alloying of aluminum (NAICS 331314)
- aluminum sheet, plate, and foil manufacturing (NAICS 331315)
- other aluminum rolling, drawing and extruding (NAICS 331318)

Figure 10. Aluminum industry process flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

Non-energy-intensive manufacturing industries

Metal-based durables industry group (NAICS 332-336): end-use method

The metal-based durables industry group consists of industries that manufacture fabricated metals; machinery; computer and electronic products; transportation equipment; and, electrical equipment, appliances, and components. Typical processes found in this group include re-melting operations followed by casting or molding, shaping, heat-treating processes, coating, and joining and assembly. Given this diversity of processes, the industry group's energy is represented using the end-use method based on the most recent MECS.[19] End-use processes for metal-based durables are the same as in bulk chemicals, as shown in Figure 5.

Other non-energy-intensive manufacturing industries: end-use method

This category is a group of non-energy-intensive industries consisting of:

- wood products
- plastics products
- light chemicals (all industries in NAICS 325 that are not bulk chemicals)
- other non-metallic minerals (all industries in NAICS 327 that are not cement, lime, or glass)
- other primary metals (all industries in NAICS 331 that are not steel or aluminum)
- miscellaneous finished goods (all other industries)

NAICS codes for these definitions are in Table 2. Wood products manufacturing is notable because the industry derives a majority of its energy from biomass in the form of wood waste and residue. The plastics manufacturing industry produces goods by processing goods from plastic materials but does not produce the plastic. The last four industries are disaggregated from the former balance of manufacturing. These industries were added as of AEO2025 and have different energy mixes and intensities. In addition, most asphalt consumption has been moved from the construction industry to miscellaneous finished goods, which includes the manufacture of paving materials and asphalt shingles. A relatively small amount of asphalt is consumed in the construction sector.

Non-manufacturing industries

The non-manufacturing industries do not have MECS as the predominant source for energy consumption data as the manufacturing industries do. Instead, we derive UECs for the agriculture, mining, and construction industries from various sources collected by a number of federal agencies, notably U.S. Department of Agriculture (USDA) and the U.S. Census Bureau. Energy consumption data for the two agriculture subsectors (crops and other agriculture) are largely based on information contained in the Farm Production Expenditures 2020 Summary conducted by the National Agricultural Statistical Service (NASS) of the USDA.[20] NASS collects data on expenditures for four energy sources for crop farms and livestock farms. We converted these data from dollar expenditures to energy quantities using prices from USDA and EIA. We used the (now suspended) EIA *Fuel Oil and Kerosene Sales* (FOKS)[21], the U.S. Census Bureau's Census of Mining[22], and the U.S. Census Bureau's Census of Construction[23] to determine distillate consumption. We also account for the use of propane fuel in the agriculture and the construction industries.

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[19] U.S. Energy Information Administration (EIA), *2018 Manufacturing Energy Consumption Survey*, http://www.eia.gov/consumption/manufacturing/index.cfm, March 2021.

[20] U.S. Department of Agriculture, Economic Research Service, Agriculture Research Management Survey (ARMS) Farm Production Expenditures 2020 Summary, July 30, 2021 (cornell.edu).

[21] U.S. Energy Information Administration, Fuel Oil and Kerosene Sales 2019, (Washington, DC, January 2021).

[22] U.S. Census Bureau, 2017 Economic Census Mining: Industry Series: Selected Supplies, Minerals Received for Preparation, Purchased Machinery, and Fuels Consumed by Type for the United States: 2017 (Washington, DC, December 15, 2020).

[23] U.S. Census Bureau, 2017 Economic Census; Construction: Industry Series: Detailed Statistics by Industry for the United States: 2017 (Washington, DC, October 8, 2021).

These sources are the most complete and consistent data available for each of the three non-manufacturing sectors. These data, supplemented by available EIA data, are used to derive total energy consumption for the non-manufacturing industrial sectors. The additional EIA data are from the *State Energy Data System*.[24] The source data relate to total energy consumption and provide no information on the processes or end uses for which the energy is consumed. Therefore, the UECs for the mining and construction industries relate energy consumption for each fuel type to value of shipments.

TPCs for non-manufacturing industries are not fixed; they change over time, unlike most manufacturing TPCs. This dynamic process is determined by output from other NEMS modules such as the Commercial Demand Module (CDM) and the Transportation Demand Module (TDM), which are used in the agriculture, construction, and mining submodules. For mine productivity, the Hydrocarbon Supply Module (HSM) provides consumption data for oil and natural gas wells, and the Coal Market Module (CMM) provides data for coal mines.

The mining industry is divided into three subsectors in the IDM: coal mining, oil and natural gas extraction, and other mining. The U.S. Census Bureau collected the quantities of seven energy types consumed by 29 mining sectors as part of the 2017 Economic Census of Mining. We aggregated the data for the 29 sectors into the 3 sectors included in the IDM, and converted the physical quantities to Btu for use in NEMS.

Only one construction subsector is included in the IDM. We aggregated the detailed statistics for the 31 construction subsectors included in the Economic Census. The U.S. Census Bureau collected expenditure amounts for five energy sources. We converted these expenditures from dollars to energy quantities using EIA price data.

IDM has submodules that calculate the non-manufacturing TPCs each year for each subsector, region, and fuel.

Agricultural submodule

U.S. agriculture consists of three major subsectors: crop production, which is determined primarily by regional environments and crops demanded; animal production, which is largely determined by food demands and feed accessibility; and all remaining agricultural activities, primarily forestry and logging. IDM calculates agriculture TPCs in the AGTPC subroutine. The energy use analysis accounts for energy used in the following categories, with the second and third categories combined for modeling purposes:

- crop production and support activities (NAICS 111 and 1151)
- animal production and support activities (NAICS 112 and 1152)
- forestry and logging and support activities (NAICS 113 and 1153)

Consumption in these industries is tied to specialized equipment, which often determines the fuel requirement with little flexibility. Within each of these subindustries, the key energy-using equipment can be broken into three major categories: off-road vehicles, buildings, and other equipment (which is

[24] U.S. Energy Information Administration, *State Energy Data System* (Washington, DC, June 2024), https://www.eia.gov/state/seds/seds-data-complete.php.

primarily irrigation equipment for crop production).[25] In the IDM, building energy consumption is driven by building characteristics retrieved from the CDM. Vehicle energy consumption is determined by vehicle efficiencies, which are retrieved from the TDM.

Mining submodule

The mining sector comprises three subsectors: coal mining, oil and natural gas extraction, metal and other non-metal mining. IDM calculates mining TPCs in the COALTPC (coal mining), OGSMTPC (oil and natural gas extraction), and OTH_MINTPC (metal and other non-metal mining) subroutines. Energy use is based on equipment used at the mine and onsite vehicles used. All mines use extraction equipment and lighting, but only coal and metal and other non-metal mines use grinding and ventilation. Characteristic of the non-manufacturing sector, efficiency changes in buildings and transportation equipment influence TPCs.

Coal mining production is obtained from the CMM. Currently, we assume approximately 70% of the coal is mined at the surface, while the rest is mined underground. As these shares evolve, however, so does the energy consumed because surface mines use less energy overall than underground mining. Moreover, the energy consumed for coal mining is based on coal mine productivity, which is also obtained from the CMM. Distillate fuel and electricity are the predominant fuels used in coal mining. Electricity used for coal grinding is calculated using the raw grinding process step from the cement industry submodule described beginning on page 95. In metal and non-metal mining, energy use is similar to coal mining. Output used for metal and non-metal mining is derived from the MAM's variable for other mining.

For oil and natural gas extraction, production is derived from the HSM. Energy use depends on the fuel extracted as well as whether the well is conventional or unconventional.

Construction submodule

IDM calculates construction TPCs in the CONTPC submodule. Construction uses electricity, natural gas, off-road distillate, off-road gasoline, propane, and asphalt and road oil. Asphalt and road oil are tied to state and local government real investment in highways and streets, and this investment is derived from the MAM. TPCs for distillate are directly tied to the TDM's heavy- and medium-duty vehicle efficiency projections. For non-vehicular construction equipment, TPCs are a weighted average of vehicular TPCs and highway investment.

Additional model assumptions

Legislative and regulatory requirements

The Energy Policy Act of 1992 (EPACT92) and the Clean Air Act Amendments of 1990 (CAAA) contain requirements that are represented in the IDM. These requirements fall into three main categories: coke oven standards; efficiency standards for boilers, furnaces, and electric motors; and industrial process technologies. The IDM assumes the leakage standards for coke oven doors do not reduce the efficiency of producing coke or increase unit energy consumption. The IDM uses heat rates of 1.25 (80% efficiency) and 1.22 (82% efficiency) for natural gas and oil burners, respectively. These efficiencies meet the EPACT92 standards. The EPACT92 electric motor standards set minimum efficiency levels for all motors

[25] Eugeni, Edward, SRA International "Report on the Analysis and Modeling Approach to Characterize and Estimate Fuel Use by End-Use Applications in the Agriculture and Construction Industries," unpublished report prepared for the Office of Energy Analysis (Washington, DC: March 2011).

up to 200 horsepower purchased after 2002. The EISA2007 increases the motor efficiency standard for all motors up to 500 horsepower purchased after 2011. The IDM incorporates the necessary reductions in unit energy consumption for the energy-intensive industries.

Section 108 of the Energy Policy Act of 2005 (EPACT05) requires that federally funded projects involving cement or concrete increase the amount of recovered mineral component (for example, fly ash or blast furnace slag) used in the cement. Such use of mineral components is a standard industry practice, and increasing the amount could reduce both the quantity of energy used for cement clinker production and the level of process-related CO_2 emissions. Because the proportion of mineral component is not specified in the legislation, possible effects of this provision are not currently simulated in the module. When specific regulations are published, their estimated impact may be modeled in NEMS. However, the current cement industry submodule does include the capability to increase the amount of blended component in the clinker mix.

Maximum Achievable Control Technology for Industrial Boilers (Boiler MACT): Section 112 of the Clean Air Act (CAA) requires the regulation of air toxics by implementing the National Standards for Hazardous Air Pollutants (NESHAP) for industrial, commercial, and institutional boilers. The final regulations, known as Boiler MACT, are modeled in the AEO. Pollutants covered by Boiler MACT include the hazardous air pollutants (HAP), hydrogen chloride (HCl), mercury (Hg), dioxin/furan, carbon monoxide (CO), and particulate matter (PM). Generally, industries comply with the Boiler MACT regulations by including regular maintenance and tune-ups for smaller facilities and emission limits and performance tests for larger facilities. Boiler MACT is modeled as an upgrade cost in the MAM. These upgrade costs are classified as *nonproductive costs*, which are not associated with efficiency improvements. The effect of these costs in the MAM is a reduction in shipments coming into the IDM.

California Assembly Bill 32: Emissions cap-and-trade as part of the Global Warming Solutions Act of 2006 (AB32) established a comprehensive, multiyear program to reduce greenhouse gas (GHG) emissions in California, including a cap-and-trade program. In addition to the cap-and-trade program, AB32 also authorizes the Low Carbon Fuel Standard (LCFS); energy efficiency goals and programs in transportation, buildings, and industry; combined heat and power goals; and renewable portfolio standards. The cap-and-trade provisions were modeled for industrial facilities, refineries, and fuel providers. GHG emissions include both CO_2 and specific non-CO_2 GHG emissions. The allowance price, representing the incremental cost of complying with AB32 cap-and-trade, is modeled in the NEMS Electricity Market Module via a region-specific emissions constraint. This allowance price, when added to market fuel prices, results in higher effective fuel prices in the demand sectors. Limited banking and borrowing, as well as a price containment reserve and offsets, have been modeled in NEMS. The basic price adjustments resulting from AB32 are determined in the Electricity Market Module (EMM) of NEMS and enter the IDM implicitly through higher effective fuel prices and the macroeconomic effects of higher prices, all of which affect energy demand and emissions.

4. Module Structure

First year: Initialize data and arrays

The first year of the projection cycle is used to set up arrays and initialize data used for projecting energy consumption. For the *Annual Energy Outlook 2025* (AEO2025), the first year of the cycle (base year) is 2018, which corresponds to the *2018 Manufacturing Energy Consumption Survey* (MECS).

The following procedures are used to initialize the Industrial Demand Module (IDM).

Read module inputs include the following:

- Read indrun.txt, which contains special run parameters. For example, it is used to turn on and off calibration to State Energy Data System (SEDS) and *Short-Term Energy Outlook* (STEO) numbers.
- Read itlbshr.txt building energy consumption for base year.
- Read cogeneration data files (called from the main industrial subroutine, IND).
- Calculate 2018 boiler fuel by subtracting Form EIA-923 cogeneration fuel from 2018 MECS indirect fuels (MecsLess860).
- Read mining input data.
- Read prodflow.txt containing process and assembly step definitions and flow rates from most recent MECS data. Define structure of prodflow arrays.
- Read itech.txt file with MECS-based UEC rates and the TPC assumptions.
- Read exogenous macroeconomic data, shipments and employment, and energy price variables from NEMS system.
- Read the initial energy and production industrial data from enprod.txt.
- Open output files for writing.

Industry processing

The IDM processes data by industry group and region. Twenty-four industry groups are represented: 6 non-manufacturing, 7 energy-intensive, and 11 non-energy-intensive manufacturing industries. Within each industry, projections are calculated for each of four census regions and summed to create a U.S.-level estimate for each industry. Below is a list of some key subroutines used in the IDM:

- RDBIN: Read memory management file with previous years' data for this industry and region. This subroutine is used to create lag variables.
- REXOG: Assign exogenous macroeconomic and energy price variables that come from NEMS global variables.
- CALBTOT: Compute consumption of energy in the buildings component for those industries that have a buildings energy component.
- CALCSC: Evaluate changes in UECs based on technological possibility curves (TPC) for end-use industries only. For non-manufacturing industries, evaluate the TPC based on external data.
- AGTPC: Calculate TPCs for agriculture industries only.
- COALTPC: Calculate TPCs for coal mining only.
- OGSMTPC: Calculate TPCs for oil and natural gas mining only.

- OTH_MINTPC: Calculate TPCs for other mining only.
- CONTPC: Calculate TPCs for construction only.
- CALPROD: Compute revised productive capacity and throughput by process and assembly step and vintage; implement retirement and vintage assumptions for end-use industries.
- CALPATOT: Compute consumption of energy in the process assembly component for end-use industries.
- CALBYPROD: Calculate consumption of byproduct fuels.
    - CALGEN: Compute on-site electricity generation for sale and internal use by fuel for all industries except iron and steel and pulp and paper. Calculates steam for cogeneration and estimates penetration of new builds. Calls the following routines:
    - COGENT: Read cogeneration assumptions spreadsheet (first year).
    - SteamSeg: Assign fraction of steam load in current load segment for current industry.
    - COGINIT: Initialize the cogeneration data arrays with capacity, generation, and fuel-use data.

Process flow industry submodules

The IS_GETDATA obtains exogenous inputs from the ironstlx.xlsx input file, which are used in the following subroutines:

- CEMENT_INDUSTRY
- LIME_INDUSTRY
- ALUMINUM_INDUSTRY
- GLASS_INDUSTRY
- IRONSTEEL_INDUSTRY
- PAPERPULP_INDUSTRY

National summaries

- NATTOTAL: Accumulate total energy consumption over all industries.
- CONTAB: Accumulate aggregates for non-manufacturing heat and power.

Apply exogenous adjustments and assign values to global variables

The WEXOG subroutine implements variable benchmarking and ultimately assigns the variables that are passed back into the NEMS restart file. WEXOG includes the following benchmarking:

- SEDS years values: calculate regional benchmark factors as the ratio of actual consumption to model consumption for each fuel in four census regions during SEDS years, and multiply model consumption by the SEDS benchmark factors.
- STEO years values: calculate national benchmark factors as the ratio of model consumption for each fuel to the STEO projection for each fuel. Disaggregate STEO values from national level to census regions using splits from last year of SEDS data.
- Post-STEO years values: Use benchmarks that are initially a combination of SEDS and STEO, shifting over 12 years to be fully SEDS-based (see below).

Main subroutines and equations

This section provides the solution algorithms for the IDM. The subroutines that are only associated with the process flow submodules are documented in the sections for cement and lime, aluminum, glass, iron and steel, and pulp and paper. The order in which the equations are presented follows the logic of the FORTRAN source code very closely to facilitate an understanding of the code and its structure. All subroutines are run for each year y, industry i, and each of the four census regions r unless otherwise indicated. Variables disaggregated to the nine census divisions use the subscript *d* to differentiate them from standard regional detail.

IND

IND is the main industrial subroutine called by NEMS. This subroutine calls some data initialization subroutines, including one to retrieve energy price and macroeconomic data (Setup_Mac_and_Price) and routines to solve the module (ISEAM) and to export its results to NEMS global variables (WEXOG).

SETUP_MAC_AND_PRICE

In subroutine Setup_Mac_and_Price, the value of shipments data from the MAM is processed. Employment is also obtained from the MAM for each non-agricultural industry. Prices for the various fuels, as well as the previous year's consumption, are obtained from NEMS COMMON blocks. The IDM energy demand projections are benchmarked to values presented in the *State Energy Data System 2023* (SEDS). The national-level values are allocated to the census divisions using this data. Because detailed data for the IDM are available only for the four census regions, the energy prices obtained from NEMS (available for each of the nine census divisions) are combined using a weighted average of the fuel prices as shown in the following equation for the first model year. A similar weighted average is used for all other fuels and model years. However, the previous year's consumption is used rather than SEDS consumption. The price for purchased electricity is given by the following:

$$PRCX_{elec} = \frac{\sum_{d=1}^{Num_r} DPRCX_{elec,d} * QSELIN_{d,\mathrm{byr}}}{\sum_{d=1}^{Num_r} QSELIN_{d,\mathrm{byr}}} \tag{1}$$

where

$PRCX_{elec}$ = price for purchased electricity;

Num_r = number of census divisions in census region r;

$DPRCX_{elec,d}$ = price of purchased electricity in census division d; and

$QSELIN_{d,byr}$ = SEDS consumption of electricity in census division d in the base year.

IND then calls ISEAM, the subroutine that guides the IDM calculations, and WEXOG, the subroutine that reports the results back to NEMS. The other fuels are calculated in the same manner.

ISEAM

ISEAM controls all of the IDM calculations and initiates some input operations. It opens external files for debugging, binary files for restarting on successive iterations and projection years, and the input data files. In the first model year and only on the first iteration, ISEAM calls RCNTRL to read the runtime parameters file (indrun.txt) and base year boiler data (itlbshr.txt). ISEAM also reads a data file, indbeu.txt, containing building energy use for lighting, heating, ventilation, and air conditioning. ISEAM calls REXOG to read in exogenous inputs on each model run. For the first model year, ISEAM calls the following subroutines for each census region within each industry: IEDATA, UECTPC, CALBYPROD, CALPATOT, CALBTOT, CALGEN, CALBSC, CALSTOT, and INDTOTAL. After the projection for the last census region for a particular industry has been calculated, the following two subroutines are called to compute totals: NATTOTAL and CONTAB. After the first model year, ISEAM calls two subroutines: RDBIN to read the restart files and MODCAL to carry out model calculations. After all model calculations have been completed, ISEAM calculates industry totals and saves information to the variables in the subroutine WRBIN. Finally, after each industry has been processed, ISEAM calls the subroutines ADDUPCOGS and INDCGN to aggregate and report industrial cogeneration estimates to NEMS.

RCNTRL

RCNTRL reads data from the input files indrun.txt and itlbshr.txt. The indrun.txt file contains internal control variables for the IDM. Data in this file are based on user-defined parameters consisting of indicator variables for subroutine tracing, debugging, writing summary tables, options to calculate model sensitivities, and benchmarking options. The itlbshr.txt data contain estimated base year boiler energy use by fuel and are used for calculating boiler fuel shares.

IEDATA

IEDATA stands for industrial enprod data, where enprod.txt is the name of the initial industrial input data file. This routine consists of many subprograms designed to retrieve industrial input data.

REXOG

REXOG prepares exogenous data obtained from MAM for use in the IDM. Dollar value of shipments and employment are aggregated over the appropriate census divisions to obtain data at the census region level. The macroeconomic variables used by the IDM are based on 2017 NAICS codes. Employment data are obtained from NEMS at the three-digit NAICS level. For some industries, employment data must be shared out among industries at a three-digit NAICS level.

IRHEADER

The IRHEADER subroutine imports industry and region identifier numbers, base year values of output, physical-to-dollar-output conversion factors, and base year steam demand.

It calculates the ratio of physical output to base year value of shipments for glass, cement, and aluminum industries. This constant ratio is applied to value of shipments for subsequent years. For the iron and steel industries, PHDRAT can vary from year to year, given as follows:

$$PHDRAT = BASE\_SHIP/PRODVX \qquad (2)$$

where

$PHDRAT$ = ratio of physical units to value of shipments (for process flow industries);

$BASE\_SHIP$ = physical units of output in the base year; and

$PRODVX$ = value of shipments.

If the unit energy consumption (UEC) is in physical units, then the following equation is used:

$$PRODX = PRODVX * PHDRAT \tag{3}$$

where

$PRODX$ = output in physical units;

$PHDRAT$ = ratio of physical units to value of shipments; and

$PRODVX$ = value of shipments.

If the UEC is in dollar units, then no physical conversion is made, and PRODX is set equal to PRODVX.

MECSBASE

The MECSBASE subroutine imports production throughput coefficients, process step retirement rates, and other process step flow information from the file prodflow.txt. Imported process step flow data for each process step include process step number, number of links, the process steps linked to the current step, physical throughput to each process step, retirement rate, and process step name. A linkage is defined as a link between one or more process steps. The module simulates process steps for three of the energy-intensive industries that use the process flowsheet method: glass, cement and lime, and aluminum.

ISEAM

The ISEAM subroutine gets building energy use data including lighting, HVAC, facility support, and on-site transportation from indbeu.txt.

IRBSCBYP

The IRBSCBYP subroutine gets byproduct fuel information for the boiler, steam, and cogeneration component. These data consist of fuel identifier numbers of steam intensity values.

RCNTL

The RCNTL subroutine reads indrun.txt and itlbshr.txt. The latter contains base year boiler-fuel use and is used to calculate boiler-fuel shares. Biomass data are retrieved in the IRBSCBYP routine.

IRCOGEN

The IRCOGEN subroutine gets cogeneration information from file exstcap.txt, including capacity, generation, fuel use, and thermal output from 1990 through 2023. Gets corresponding data for planned units from file plancap.txt.

IRSTEPBYP

The IRSTEPBYP subroutine gets byproduct data for process and assembly component. These data consist of fuel identifier numbers and heat intensity values.

UECTPC

The UECTPC subroutine reads the industrial technology data file (itech.txt) to update the initial enprod.txt data file with base year values of UECs and TPCs.

IFINLCALC

The IFINLCALC subroutine calculates initial year values for process step production throughput for the energy-intensive industries.

Specialized subroutines

These subroutines perform calculations for energy consumption and output results that can be used by other modules of NEMS. Specialized subroutines calculate process and assembly energy for end-use manufacturing industries and steam allocation to boiler or CHP (except iron and steel and pulp and paper). The description of energy consumption calculations for non-manufacturing industries starts on page 82, and energy consumption calculations for process-flow industries (cement, aluminum, glass, iron and steel, and pulp and paper) starts on page 95.

CALPATOT

CALPATOT calculates the total energy consumption from the process and assembly (PA) component. Energy consumption at each process step is determined by multiplying the current production at a particular process step by the UEC for that process step.

The annual UEC for the old and new vintage is calculated as the product of the previous year's UEC and a factor that reflects the assumed rate of intensity decline over time and the impact of energy price changes on the assumed decline rate, given as follows:

$$Enpint_{v,f,s,y} = EnpintLag_{v,f,s,y} * (1 + TPCRate_v) \tag{4}$$

where

$Enpint_{v,f,s}$ = unit energy consumption of fuel f at process step s for vintage v;
$EnpintLag_{v,f,s}$ = previous year's energy consumption of fuel f at process step s for vintage v; and
$TPCRate_v$ = energy intensity decline rate for vintage v after accounting for the impact of increased energy prices.

The values for $TPCRate_v$ are calculated using the following relationships if the fuel price is higher than it was in the base year. Otherwise, the default value for the intensity decline rate ($BCSC_{v,f,s}$) is used.

$$Pricerat_y = \max\left(1, \frac{AvgPrice_y}{AvgPrice_{ibyr}}\right) \tag{5}$$

$$TPCPriceFactor_y = \frac{Pricerat_y^{TPCBeta}}{1 + Pricerat_y^{TPCBeta}} \tag{6}$$

$$TPCRate_{v,f,s,y} = 2 * TPCPriceFactor_y * BCSC_{v,f,s} \tag{7}$$

where

$Pricerat_y$ = ratio of current year average industrial energy price to base year price;

$TPCBeta$ = parameter of logistic function, currently specified as 4;

$TPCPriceFactor_y$ = TPC price factor, ranging from 0 (no price effect) to 1;

$TPCRate_{v,f,s,y}$ = energy intensity for capital of vintage v, fuel f, step s, and year y after accounting for changes due to energy price changes for vintage v; and

$BCSC_{v,f,s}$ = default intensity rate for old and new vintage v for each fuel f and step s.

The old vintage consists of capital in production in the base year and is assumed to retire at a fixed rate each year. Middle vintage capital is that which is added from the base year through the year $y-1$, where y is the current projection year. New capital is added for the projection years when existing production is less than the output projected by the MAM. Capital stock added during the projection period is retired in subsequent years at the same rate as the pre-2007 capital stock.

Estimates of existing old and middle vintage production are reduced by the retirement rate of capital through the equations, as follows:

$$RetirePriceFactor_y = \frac{Pricerat_y^{RetireBeta}}{\left(1 + Pricerat_y^{RetireBeta}\right)} \tag{8}$$

$$RetireRate_{s,y} = 2 * RetirePriceFactor_y {}^* \; ProdRetr_s \tag{9}$$

where

$Pricerat_y$ = is defined on page 55;

$RetireBeta$ = parameter of logistic function, currently specified as 2 for capital stock retirement;

$RetirePriceFactor_y$ = TPC price factor in year y, ranging from 0 (no price effect) to 2;

$RetireRate_{s,y}$ = retirement rate in year y after accounting for energy price increases for step s; and

$ProdRetr_s$ = default retirement rate for step s.

Energy consumption is calculated for each fuel, vintage, and step using the following equation:

$$ENPQTY_{v,f,s} = PRODCUR_{v,s} * ENPINT_{v,f,s} \tag{10}$$

where

$ENPQTY_{v,f,s}$ = consumption of fuel f at process step s for vintage v;

$PRODCUR_{v,s}$ = production at process step s, for vintage v; and

$ENPINT_{v,f,s}$ = unit energy consumption of fuel f at process step s for vintage v.

Consumption of each fuel is converted to trillions of Btu. Energy consumption is subdivided into main fuels, intermediate fuels, and renewable fuels. The main fuel group includes the following[26]:

- purchased electricity
- core and non-core natural gas
- natural gas feedstocks
- steam coal
- coking coal (including net coke imports)
- residual oil
- distillate oil
- propane for heat and power
- hydrocarbon gas liquids (including propane) feedstocks
- motor gasoline
- still gas
- petroleum coke
- asphalt and road oil
- petrochemical (naphtha) feedstock
- other petroleum

The intermediate fuel group includes the following:

- steam
- coke oven gas
- blast furnace gas
- other byproduct gas
- waste heat
- coke

The renewable fuels group represented in the module includes the following:

- hydropower
- biomass—wood
- biomass—pulping liquor
- municipal solid waste

Geothermal, solar, and wind are currently not represented in the module because of their low industrial penetration.

[26]Still gas and petroleum coke are consumed primarily in the refining industry, which is modeled in the Liquid Fuels Market Module of NEMS.

Energy consumption for the three fuel groups is determined for each fuel by summing over the process steps and the three vintage categories, as shown below for main fuels. The equations for intermediate and renewable fuels are similar, as shown by the following:

$$ENPMQTY_f = \sum_{s=1}^{MPASTP} \sum_{v=1}^{3} ENPQTY_{v,f,s} \tag{11}$$

where

$ENPMQTY_f$ = consumption of main fuel f in the process and assembly component;

$MPASTP$ = number of process step s; and

$ENPQTY_{v,f,s}$ = consumption of fuel f at process step s for all vintages *v*.

Additional energy demand to grow corn for ethanol production

Higher demand for corn-based ethanol increases the use of energy in the agricultural industry, as well as the use of energy to produce fertilizer in the agricultural chemical subsector of the bulk chemicals industry. While this demand is accounted for in the base year values, ethanol production volumes in later years come from the LFMM, and change at a different rate than the rest of the agricultural sector (which grows based on macroeconomic series from the MAM). We project the effect of increased corn-based ethanol production on energy used in agriculture and in producing nitrogenous fertilizer in the chemical sector as follows:

$$CORNFUEL_f = \sum_{f=1}^{5} CORNFAC_f * CORNINCR\_FUEL_y \tag{12}$$

$$NITROFUEL = NITROFAC * CORNINCR\_FEED_y \tag{13}$$

where

$CORNFUEL_f$ = consumption of fuel f in agricultural production for ethanol feedstocks;

$CORNFAC_f$ = thousand Btu of fuel f to produce 1 bushel of corn;

$CORNINCR\_FUEL_y$ = incremental change in corn production between year y and the IDM base year for the fuels;

$NITROFUEL$ = consumption of natural gas feedstock for fertilizer produced to grow corn for ethanol feedstocks;

$NITROFACT$ = 23.4 thousand Btu hydrogen feedstock per bushel of corn; and

$CORNINCR\_FEED_y$ = incremental change in corn production between year y and the last year of natural gas feedstock data in the feedstock.csv input file.

The fuels for agricultural production of corn, f, are electricity, natural gas, distillate, propane, and motor gasoline. The increased energy requirements are then added to the demand for the agricultural crops industry (NAICS 111) and, for fertilizer feedstocks, to the agricultural chemicals industry (NAICS 3253).

Coke imports

We calculate energy consumption for coke imports as the difference between coke consumption and coke production. In the current IDM, coke is consumed only in the BF/BOF process step in the iron and steel industry. Coke is produced only in the coke oven process step in the iron and steel industry. The equation for net coke imports is shown below:

$$ENPMQTY_{coke} = ENPIQTY_{coke} - \left(PRODCUR_{total,co} * \frac{27.34}{10^6}\right) \tag{14}$$

where

$ENPMQTY_{coke}$ = quantity of coke imports in the PA component;

$ENPIQTY_{coke}$ = consumption of coke in the PA component;

$PRODCUR_{total,co}$ = current production at the coke oven process step for all vintages; and

$27.34/10^6$ = unit conversion factor of heat content per short ton of coke.

CALBTOT

CALBTOT calculates the total energy consumption for the buildings portion of the IDM. Building energy consumption is calculated for three building uses: lighting; heating, ventilation, and air conditioning (HVAC); and on-site transportation. Total energy consumption is determined as a weighted average of the industry employment UEC and the industry output UEC, as follows:

$$ENBQTY_{e,f} = \left(EWeight^{*}\left[EMPLX^{*}ENBINT_{e.f}\right] + PWeight * \left[ProdVX^{*}ONBINT_{e,f}\right]\right) * BldPFac \tag{15}$$

where

$ENBQTY_{e,f}$ = consumption of fuel f for building end use e;

$EMPLX$ = employment in thousands;

$ProdVX$ = output in million 2012 dollars;

$ENBINT_{e,f}$ = employment unit energy consumption (trillion Btu per thousand employees) of fuel f for building end use e;

$ONBINT_{e,f}$ = output unit energy consumption of fuel f for building end use e;

$EWeight$ = weight for employment unit energy consumption (0.7);

$PWeight$ = weight for output unit energy consumption (0.3); and

$BldPFac$ = effect of energy price increases on buildings energy consumption.

The $BldPFac$ variable adjusts buildings energy consumption if the average industrial energy price increases above a threshold. Below the threshold, $BldPFac$ is equal to 1. Above the threshold, the value of $BldPFac$ is calculated as follows:

$$BldPFac = BldPRat^{BldElas} \tag{16}$$

where

$BldPRat$ = ratio of current year's average industrial energy price to the base year price; and

$BldElas$ = assumed elasticity, currently -0.5.

CALGEN

Subroutine CALGEN accounts for electricity generation from cogeneration. It combines estimated existing and planned cogeneration with new projected cogeneration based on an endogenous economic and engineering evaluation. The subroutine estimates market penetration of new (not currently planned) cogeneration capacity as a function of steam load, steam already met through cogeneration, and cost and performance factors affecting cogeneration economics. CALGEN calls subroutine COGENT to read in the cogeneration assumptions and calls subroutine EvalCogen to evaluate the economics of prototypical cogeneration systems sized to match steam loads in eight size ranges. A function, SteamSeg, is also called to access a size distribution of steam loads for each industry. Generation for own use and electricity sales to the grid are calculated based on total generation and the shares of sales to the grid reported on Form EIA-860 data[27].

CALGEN computes total steam demand as the sum of steam use in buildings (HVAC being the only system using steam) and steam use from the process and assembly component, as follows[28]:

$$STEMCUR = ENBQTY_{hvac,steam} + ENPIQTY_{steam} \tag{17}$$

where

$STEMCUR$ = total steam demand;

$ENBQTY_{hvac,steam}$ = consumption of steam for HVAC; and

$ENPIQTY_{steam}$ = consumption of steam in the process and assembly component.

Next, the portion of steam requirements that could be met by new cogeneration plants, up to the current model year, is determined as follows:

$$NonCogSteam = STEMCUR - CogSteam \tag{18}$$

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[27]Several subroutines not shown here perform the calculations required to initialize, aggregate, and summarize the cogeneration data derived from Form EIA-860, Form EIA-923, and predecessor EIA surveys. These subroutines also incorporate changes from module additions. They include IRCOGEN, COGINIT, MECSLESS860, and ADDUPCOGS.

[28]This subroutine also calculates the amount of steam produced by byproduct fuels, which reduces the amount of steam required to be produced by purchased fuels.

where

$NonCogSteam$ = non-cogenerated steam based on existing cogeneration capacity;

$STEMCUR$ = total steam demand; and

$CogSteam$ = steam met by existing cogeneration units as of the last data year.

Non-cogeneration steam uses are disaggregated into eight size ranges, or segments, based on an exogenous data set providing the boiler size distribution for each industry. These data are accessed in the function SteamSeg. Steam load segments are assumed to be distributed in the same proportions as boiler capacity, as follows:

$$AggSteamLoad_{loadsegment} = NonCogSteam * SteamSeg_{loadsegment} \tag{19}$$

where

$AggSteamLoad_{loadsegment}$ = steam demand for a given load segment; and

$SteamSeg_{loadsegment}$ = the fraction of total steam in each of eight boiler firing ranges, in million Btu/hour, with the ranges being 1.5–3, 3–6.5, 6.5–10, 10–50, 50–100, 100–250, 250–500, and more than 500.

The average hourly steam load, $AvgHourlyLoad_{loadsegment}$ in each segment is calculated from the aggregate steam load, $AggSteamLoad_{loadsegment}$, based on 8,760 operating hours per year and converting from trillions to millions of Btu per hour, as follows:

$$AveHourlyLoad_{loadsegment} = \frac{AggSteamLoad_{loadsegment}}{0.008760} \tag{20}$$

The maximum technical potential for cogeneration is calculated assuming all non-cogeneration steam demand for each load segment is converted to cogeneration. This calculation assumes that the technical potential is based on sizing systems, on average, to meet the average hourly steam load in each load segment. The number of system or segment options is *nsys*, currently eight, and each system is indicated by the subscript *isys*. Using the power-steam ratio of the prototype cogeneration system selected for each load segment (from subroutine EvalCogen), this calculation is given as follows:

$$TechPot_{loadsegment} = AvgHourlyLoad_{loadsegment} * PowerSteam_{isys} \tag{21}$$

where

$TechPot_{loadsegment}$ = technical potential for cogeneration, in megawatts, for a load segment, irrespective of the economics;

$AveHourlyLoad_{loadsegment}$ = average hourly steam load in each load segment; and

$PowerSteam_{isys}$ = power-steam ratio of the cogeneration unit, $isys$, which is equivalent to the ratio of electrical efficiency to thermal efficiency.

The economic potential for cogeneration is estimated from the technical potential by applying the estimated fraction of that potential that will be realized over an extended time period, based on market acceptance criteria (as applied in subroutine EvalCogen), as follows:

$$EconPot_{loadsegment} = TechPot_{loadsegment} * EconFrac_{loadsegment} \tag{22}$$

where

$EconPot_{loadsegment}$ = economic potential for cogeneration in megawatts;

$TechPot_{loadsegment}$ = technical potential for cogeneration, in megawatts, for a load segment if all cogeneration was adopted, irrespective of the economics; and

$EconFrac_{loadsegment}$ = economic fraction based on the payback period and the assumed payback acceptance curve.

Given the total economic potential for cogeneration, the amount of capacity that would be added in the current model year is given by the following:

$$CapAddMW_{loadsegment} = EconPot_{loadsegment} * PenetrationRate \tag{23}$$

where

$CapAddMW_{loadsegment}$= cogeneration capacity added, in megawatts, for a load segment;

$EconPot_{loadsegment}$ = economic potential for cogeneration in megawatts; and

$PenetrationRate$ = constant annual rate of penetration, assumed to be 5% based on the economic potential being adopted over a 20-year time period; also includes collaboration coefficients provided by the American Council for an Energy-Efficient Economy (ACEEE)[29] that show the relative likelihood of CHP adoption among U.S. regions.

Based on the results of a study performed for EIA,[30] which includes cogeneration system cost and performance characteristics, capacity additions are assumed to be natural-gas-fired except in certain industries that are known to use biomass for existing CHP, notably pulp and paper products. The corresponding generation and fuel use from these aggregated capacity additions are calculated from the assumed capacity factors and heat rates of the prototypical systems. The energy characteristics of the additions are used to increment the module's cogeneration data arrays: capacity (COGCAP), generation (COGGEN), thermal output (COGTHR), and electricity-related-fuel use (COGELF). These arrays are all indexed by census division, year, industry, and fuel. Because the module runs at the census region level,

[29] American Council for an Energy-Efficient Economy, "Challenges Facing Combined Heat and Power Today: A State-by-State Assessment," September 2011, http://aceee.org/research-report/ie111, and U.S. Energy Information Administration, Office of Energy Analysis.

[30] SENTECH Inc., *Commercial and Industrial CHP Technology Cost and Performance Data for EIA*, report prepared for the Office of Integrated Analysis and Forecasting, Energy Information Administration, Washington, DC, June 2014.

regional results are shared equally among the census divisions using a factor, $DSHR$, where $DSHR$ is either one half or one-third. The assignment statements to increment the arrays are as follows:

$$COGGEN_{d,ngas,y} = COGGEN_{d,ngas,y-1} + CAPADDGWH * DSHR \tag{24}$$

$$COGCAP_{d,ngas,t} = COGCAP_{d,ngas,y-1} + CAPADDGWH * DSHR \tag{25}$$

$$COGTHR_{d,ngas,y} = COGTHR_{d,ngas,y-1} + STMADDTRIL * DSHR \tag{26}$$

$$COGELF_{d,ngas,y} = COGELF_{d,ngas,y-1} * \left(\frac{CAPADDGWH * AVEHTRT}{10^6} - \frac{STMADDTRIL}{0.8}\right) * DSHR \tag{27}$$

where

$CAPADDGWH$ = generation from new capacity in gigawatthours;

$STMADDTRIL$ = thermal (steam) output of new capacity in trillion Btu; and

$AVEHTRT$ = heat rate, or total fuel use per unit of generation in Btu/kWh.

Cogeneration from biomass (*BIO*) is also directly related to the amount of biomass available for that industry (calculated in subroutine CALBYPROD), which is calculated as follows:

$$BIO_y = MAX\left(0, \frac{BioAvail_y - BioAvail_{y-1}}{HeatRate}\right) \tag{28}$$

where

$BioAvail_y$ = biomass available for generation in model year y; and

$HeatRate$ = converts Btu to kWh (assumed to be 25,000 Btu/kWh through 2003 and decline linearly to 17,000 Btu/kWh by 2020).

The available biomass generation is then added to the current year's cogeneration arrays by the following calculation (incremental assignment shown) as follows:

$$COGGEN_{d,biomass,y} = COGGEN_{d,biomass} + BIO^{*}DSHR \tag{29}$$

where

$COGGEN_{d,biomass}$ = total biomass cogeneration by census division d; and

$DSHR$ = factor to share census region addition to census divisions such that each division gets an equal share.

The biomass capacity, thermal output, and electricity-related fuel use associated with the generation (*BIO*) are used to increment the corresponding cogeneration data arrays, *COGCAP*, *COGTHR*, and *COGELF*, respectively.

Once the energy input and output characteristics of the cogeneration capacity additions have been combined with those of the existing capacity, the effect of cogeneration on purchased electricity demand and conventional fuel use can be determined.

The cogeneration capacity values (*COGCAP*) are used only for reporting purposes and are not used within the IDM. The thermal output and fuel use from cogeneration, derived from arrays *COGTHR* and *COGELF*, are used in subroutine CALSTOT (see below) to determine the balance of the industry's steam demand that must be met by conventional boilers, and then this balance is combined with boiler fuel use to estimate total boiler, steam, and cogeneration (BSC) component energy requirements.

The amount of cogenerated electricity used on site (own-use) is estimated, and the balance of total electricity needs are met from purchased electricity. The shares of electricity generation for grid sales and own-use are derived from Form EIA-860 survey data and are assumed to remain constant for existing capacity. The grid share for each census division, industry, and fuel, by year, is maintained in array $COGGRD_{d,f}$. In most industries, capacity additions are assumed to have the same grid or own-use shares as that of the average (across regions) of the existing capacity for 2017 through 2021. As capacity is added, the average grid-sales share for each region and industry (*COGGRD*) is recomputed as follows:

$$NEWGEN_{d,f} = CapAddGWH_f * DSHR_d \tag{30}$$

$$OLDGRD_{d,f} = COGGEN_{d,f} + COGGRD_{d,f} \tag{31}$$

$$NEWGRD_{d,f} = NEWGEN_{d,f} * COGGRDNEW_d \tag{32}$$

$$COGGRD_{d,f} = \frac{\left(OLDGRD_{d,f} + NEWGRD_{d,f}\right)}{\left(COGGEN_{d,f} + NEWGEN_{d,f}\right)} \tag{33}$$

Electricity generation for own use is then calculated as follows:

$$ELOWN = \sum_d \sum_f \left(COGGEN_{d,f} + COGGRD_{d,f}\right) \tag{34}$$

where

$ELOWN =$ electricity generation for own use;

$COGGEN_{d,f}$ and $COGGRD_{d,f}$ are defined above; and

Electricity generation for sales to the grid is calculated similarly.

EvalCogen

Subroutine EvalCogen is called by subroutine CALGEN to evaluate a set of prototype cogeneration systems sized to match steam loads in eight size ranges, or load segments. The thermal capacities of the systems are assigned to approximately match the average boiler size in each industry for each of the following ranges (in million Btu per hour): 1.5−3, 3−6.5, 6.5−10, 10−50, 50−100, 100−250, 250−500, and more than 500. The corresponding steam output, or steam load, is determined from the average boiler capacity as follows:

$$SteamLoad_{loadsegment} = AveBoilSize_{loadsegment} * EboilEff_{loadsegment} \quad (35)$$

where

$SteamLoad_{loadsegment}$	= steam output of average boiler in the load segment, in million Btu per hour;
$AveBoilSize_{loadsegment}$	= firing capacity of average boiler in the load segment; and
$EboilEff_{loadsegment}$	= assumed boiler efficiency.

For each load segment, the module preselects a candidate cogeneration system with thermal output that approximately matches the steam output of the average-sized boiler in the load segment. The module relies on the following user-supplied set of characteristics for each cogeneration system, as follows:

$CogSizeKW_{isys}$	= net electric generation capacity in kW;
$CogCapCostKW_{isys}$	= total installed cost, in 2005 dollars per kilowatthour;
$CapFac_{isys}$	= system capacity factor;
$CHeatRate_{isys}$	= total fuel use per kilowatthour generated (Btu/kWh); and
$OverAllEff_{isys}$	= fraction of input energy converted to useful heat and power.

From the above user-supplied characteristics, the following additional parameters for each system are derived:

$ElecGenEff_{isys}$ = fraction of input energy converted to electric energy, or electric energy efficiency;

$\approx 3412 / CHeatRate_{isys}$

$ElecSizeMWh_{isys}$ = electric generation from the cogeneration plant in megawatthours;

$\approx CogSizeKW_{isys} * 8.76 * CapFac_{isys}$

$FuelUse_{isys}$ = cogeneration system fuel use per year in billion Btu;

$\approx ElecSizeMWh_{isys} * CHeatRate_{isys} / 10^6$

$PowerSteam_{isys}$ = ratio of electric power output to thermal output;

$\approx ElecGenEff_{isys} / \left(OverAllEff_{isys} - ElecGenEff_{isys}\right)$

$SteamOutput_{isys}$ = thermal output of the cogeneration system in MMBtu per hour; and

$\approx CogSizeKW_{isys} * 0.003412 / PowerSteam_{isys}$

$disrate$ = real discount rate, which is the 10-year Treasury bill rate adjusted for risk.

For consistency, the system number for each steam load segment is the same as the subscript *isys*:

$$CogSys_{loadsegment} = isys \tag{36}$$

Next, the module estimates the investment payback period ($Cpayback_{loadsegment}$) required to recover the aggregate cogeneration investment for each load segment. This figure is determined by estimating the annual cash flow from the investment, defined as the value of the cogenerated electricity, less the cost of the incremental fuel required for generation. For this purpose, the annual cost of fuel (natural gas) and the value of the electricity are based on the prices averaged over the first 10 years of operating the cogeneration system. The electricity is valued at the average industrial electricity price in the region, net of standby charges that would be incurred after installing cogeneration (*CogElecPrice*).

The standby charges are assumed to be the user-specified fraction of the industrial electricity rate (10%). For natural gas (*CogFuelPrice*), the price of firm-contract natural gas was assumed to apply. The steps performed in each annual module loop are as follows:

Determine annual fuel cost of the aggregated cogeneration systems in each load segment:

$$FuelCost_{loadsegment} = FuelUse_{isys} * CogFuelPrice \tag{37}$$

Determine the annual fuel use and cost of operating the existing system (conventional boiler):

$$ExistFuelUse_{loadsegment} = \frac{SteamOutput_{isys} * 8.76 * CapFac_{isys}}{EboilEff_{loadsegment}} \tag{38}$$

$$ExistFuelCost_{loadsegment} = ExistFuelUse_{loadsegment} * CogFuelPrice \tag{39}$$

Determine incremental fuel cost and the value of cogenerated electricity:

$$IncrFuelCost_{loadsegment} = FuelCost_{loadsegment} - ExistFuelCost_{loadsegment} \tag{40}$$

$$ElecValue_{loadsegment} = ElecSizeMWh_{isys} * CogElecPrice * 0.003412 \tag{41}$$

Determine the cash flow, or operating profit, of the investment:

$$OperProfit_{loadsegment} = ElecValue_{loadsegment} - IncrFuelCost_{loadsegment} \tag{42}$$

Determine the investment capital cost and the investment payback period:

$$Investment_{loadsegment} = CogSizeKW_{isys} * CogCapCostKW_{isys} \tag{43}$$

$$CPayBack_{loadsegment,y} = \frac{Investment_{loadsegment}}{OperProfit_{loadsegment} \frac{1}{(1 + disrate)^y}} \tag{44}$$

Given the payback for the aggregated system evaluated for each load segment, the module estimates the fraction of total technical potential considered economical. This calculation uses an assumed distribution of required investment payback periods, referred to as the payback acceptance curve. A table of assumptions is used containing acceptance rates for each integer payback period from 0 to 12 years. We use a linear interpolation to obtain an acceptance fraction, or economic fraction, from a non-integer value for payback. The economic fraction is determined from a table lookup and interpolation function called Acceptance.

Given the table of acceptance fractions, the number of rows in the table (13), and the payback period for the load segment, the calculation is

$$EconFrac_{loadsegment} = Acceptance\left(AcceptFrac, 13, CPayBack_{loadsegment}\right) \quad (45)$$

where

$EconFrac_{loadsegment}$ = fraction of cogeneration investments adopted based on payback period of acceptance assumptions;

$AcceptFrac$ = array of payback acceptance rates corresponding to integer payback periods ranging from 0 to 12 (13 rates altogether); and

$CPayBack_{loadsegment}$ = cogeneration investment payback period.

CALSTOT

CALSTOT calculates total fuel consumption in the boiler, steam, and cogeneration (BSC) component based on total steam demand within an industry (*STEMCUR*). Steam demand and fuel consumption (in Btu) are allocated between cogeneration and conventional boilers. Fuel use and steam demand from cogeneration, calculated in subroutine CALGEN, are treated as inputs to this subroutine.

Steam from cogeneration (*COGSTEAM*) is obtained by summing the cogeneration thermal output (in array *COGTHR*) across fuels and census divisions. Steam demand to be met by conventional boilers (*NonCOGSTEAM*) is equal to total steam demand (*STEMCUR*) minus cogeneration steam (*COGSTEAM*) production.

The estimated consumption of fuel for cogeneration is stored in two variables: fuel used to generate electricity (*COGELF*) and fuel associated with the thermal output (*COGTHR*). The fuel associated with the thermal output assumes a hypothetical 80% efficiency, so it is computed as *COGTHR* divided by 0.8. Thus, total cogeneration system fuel use, $FuelSys_f$, is given by the following:

$$FuelSys_f = \sum_d \left(COGELF_{d,f} + COGTHR_{d,f}/0.8\right) \quad (46)$$

Conventional boiler fuel use is split between biomass-derived fuels and fossil fuels. The total available biomass is calculated as byproduct fuels ($BYPBSCR_{biofuel}$). Some of it is used in cogeneration; the remainder of the available biomass (*AvailBiomass*) is assumed to be used as boiler fuel. The amount of steam from this biomass (*BIOSTEAM*) is estimated based on assumed biomass boiler efficiency (0.69).

The steam demand that must be met through fossil fuel-fired boilers is the total non-cogenerated steam (*NonCogSteam*) less the biofueled steam (*BIOSTEAM* or *NonCogFosSteam*). A trial estimate for total fossil fuel for boilers is derived from *NonCogFosSteam* and assumes average boiler efficiency across fuels.

Allocating this total to specific fuels in a manner consistent with MECS data is difficult. The MECS data indicate only the total amounts of indirect fuels associated with boilers and cogeneration, so fuel-specific boiler use cannot be computed from MECS data alone. Because fuel use and thermal output data is taken from Form EIA-860, deriving an estimated conventional boiler fuel requirement consistent with MECS requires a calibration step. The module calibrates the fuel volumes to ensure that the sum of the cogeneration fuel and conventional boiler fuel (from Form EIA-860) equals the MECS indirect fuel estimate in the base year.

The derivation of the boiler fuel calibration factor is based on the results of subroutine MecsLess860, which, as its name implies, calculates the difference between total MECS indirect fuels (*BSCbsyr*) and the cogeneration (or CHP) fuel use from Form EIA-860 (*CHPbsyr*) and stores it in array *BOILBSYR*. A separate calibration is performed for biomass- and fossil-fueled boilers. The calibration factor for fossil fuels is computed as follows for the base year:

$$Estimated = NonCogFosSteam / \, 0.8 \tag{47}$$

$$Implied = \sum_f BOILIBYR_f \tag{48}$$

$$CALIBBSYR\_FOS = \, Implied / \, Estimated \tag{49}$$

where

$Estimated$ = preliminary estimate of fossil fuel use from conventional boilers;

$Implied$ = conventional boiler fuel use;

$BOILIBYR_f$ = ratio of MECS and Form EIA-860 for each boiler fuel f; and

$CALIBBSYR\_FOS$ = calibration factor for conventional boiler fuel use.

In the projection, the calibration factors for the base year adjust the preliminary estimates to yield the estimated non-cogeneration fossil fuel, as follows:

$$NonCogFosFuel \;=\; NonCogFosSteam \, * \, BSSHR_f \tag{50}$$

where

$NonCogFosFuel$ = non-cogeneration (conventional) fossil fuel use in boilers, calibrated to match MECS when combined with Form EIA-860 cogeneration data;

$BSSHR_f$ = boiler fuel shares estimated in subroutine CALBSC; and

Conventional boiler fuel use ($FuelFosSteam_f$) is allocated to fuels based on fuel shares adjusted for price changes since the base year and fuel-specific efficiencies, as follows:

$$FuelFosSteam_f = \left(NonCogFosFuel \mathbin{/} beff_f\right) * CALIBBSYR\_FOS \tag{51}$$

where

$beff_f$ = boiler efficiency by fuel given in Table 7.

Table 7. Boiler efficiency by fuel

Fuel	Efficiency (percentage)
natural gas	78%
coal	83%
residual oil	84%
distillate	80%
propane	76%
electricity	98%
petroleum coke	80%
other	80%
biomass	69%

Source: Personal communication with Council of Industrial Boiler Owners, 2011 and Schoeneberger et al. (2022)

The fossil fuels consumption for non-cogeneration boilers is added to cogeneration fuel consumption to yield total fuel consumption in the boiler, steam, and cogeneration (BSC) component, as follows:

$$ENSQTY_f = CogBoilFuel_f + FosFuelSteam_f \tag{52}$$

where

$CogBoilFuel_f$ = fossil fuel consumption for cogeneration by fuel f; and

$FosFuelSteam_f$ = fossil fuel consumption for conventional boilers by fuel f.

INDTOTAL

The consumption estimates derived in the PA, BSC, and BLD components are combined in INDTOTAL to estimate overall energy consumption for each industry. The consumption estimates include byproduct consumption for each of the main, intermediate, and renewable fuels. Only electricity, natural gas, and steam are included in building consumption. For all fuels except electricity, the following equation is used:

$$QTYMAIN_{f,r,i} = ENPMQTY_{f,r,i} + ENBQTYTOT_{f,r,i} + ENSQTY_{f,r,i} + BYPBSCM_{f,r,i} \tag{53}$$

where

$QTYMAIN_{,f,r,i}$ = consumption of fuel f and region r;

$ENPMQTY_{f,r,i}$ = consumption of fuel f and region r in the PA component;

$ENBQTYTOT_{f,r,i}$ = consumption of fuel f and region r for all building end uses;

$ENSQTY_{f,r,i}$ = consumption of fuel f and region r to generate steam; and

$BYPBSCM_{f,r,i}$ = byproduct consumption of fuel f and region r to generate electricity from the BSC component.

For modeling purposes, consumption of electricity is defined as purchased electricity only; therefore, electricity generation for own use is removed from the consumption estimate as follows:

$$QTYMAIN_{,elec,r,i} = ENPMQTY_{elec,r,i} + ENBQTYTOT_{elec,r,i} - ELOWN_{r,i} \tag{54}$$

where

$QTYMAIN_{elec,r}$ = consumption of purchased electricity in region r ;

$ENPMQTY_{elec,r}$ = consumption of electricity in the PA component in region r;

$ENBQTYTOT_{elec,r}$ = consumption of electricity for all building end uses; and

$ELOWN_r$ = electricity generated for own use, from subroutine CALGEN.

NATTOTAL

After calculating energy consumption for all four census regions for an industry, NATTOTAL computes a national industry estimate of energy consumption. This subroutine also computes the consumption total over all fuel categories (main, intermediate, and renewable). Total consumption for the entire industrial sector for each main, intermediate, and renewable fuel is computed by accumulating across all industries as follows:

$$TQMAIN_f = \sum_{r=1}^{4} \sum_{i=1}^{INDMAX} QTYMAIN_{f,r,i} \tag{55}$$

where

$TQMAIN_f$ = total national consumption for fuel f;

$INDMAX$ = total number of industries; and

$QTYMAIN_{f,r,i}$ = consumption of fuel f for census region r and industry i.

CONTAB

CONTAB reports consumption values for individual industries. National consumption values are reported for each of the fuels used in each particular industry. The procedure for main fuels in the food products industry is calculated as follows[31] (with similar equations used for the other industries, which have different values of i):

[31]Another subroutine, INDFILLCON, is called from CONTAB to actually fill the FOODCON consumption array.

$$FOODCON_f = \sum_{r=1}^{4} QTYMAIN_{f,r,i=7} \quad (56)$$

where

$FOODCON_f$ = total national consumption of fuel f in the food products industry; and

$QTYMAIN_{f,r,i=7}$ = consumption of fuel f for census region r in the food products industry.

WRBIN

WRBIN writes data for each industry to a binary file. Two different binary files are created. The first contains variables and coefficients that do not change over time but vary over industry or process. The second binary file contains data that vary by projection year.

INDCGN

Subroutine INDCGN calculates aggregate industrial sector cogeneration capacity, generation, and fuel use by summing the results of subroutine CALGEN over all the industries. Subroutine INDCGN shares these cogeneration results into two parts: that associated with generation for own use and that used for sales to the grid. The results are copied to the corresponding NEMS global data variables for industrial cogeneration capacity (*CGINDCAP*), generation (*CGINDGEN*), and fuel use (*CGINDQ*), as follows:

$$CGINDCAP_{d,f,grid} = \sum_{i}^{indmax} \left(COGCAP_{d,i,f} * COGGRD_{d,i,f}\right) \quad (57)$$

$$CGINDCAP_{d,f,ownuse} = \sum_{i}^{indmax} \left(COGCAP_{d,i,f} * \left(1 - COGGRD_{d,i,f}\right)\right) \quad (58)$$

$$CGINDGEN_{d,f,grid} = \sum_{i}^{indmax} \left(COGGEN_{d,i,f} * COGGRD_{d,i,f}\right) \quad (59)$$

$$CGINDGEN_{d,f,ownuse} = \sum_{i}^{indmax} \left(COGGEN_{d,i,f} * \left(1 - COGGRD_{d,i,f}\right)\right) \quad (60)$$

$$CGINDQ_{d,f,grid} = \sum_{i}^{indmax} \left(COGELF_{d,i,f} * COGGRD_{d,i,f}\right) \quad (61)$$

$$CGINDQ_{d,f,ownuse} = \sum_{i}^{indmax} \left(COGELF_{d,i,f} * \left(1 - COGGRD_{d,i,f}\right)\right) \quad (62)$$

where

$CGINDCAP_{d,f,u}$ = cogeneration capacity by census division d, fuel f, and use u where u=1 is grid and u=2 is own use.

$CGINDGEN_{d,f,u}$ = cogeneration generation by census division d, fuel f, and use u;

$CGINDQ_{d,f,u}$ = cogeneration fuel use, electricity portion, by census division d, fuel f, and use u;

$COGGRD_{d,i,f}$ = share of cogeneration sold to the grid by census division d, industry i, and fuel f;

$COGCAP_{d,i,f}$ = cogeneration capacity by census division d, industry i, and fuel f;

$COGGEN_{d,i,f}$ = cogeneration generation by census division d, industry i, and fuel f; and

$COGELF_{d,i,f}$ = cogeneration fuel use, electricity portion, by census division d, industry i, and fuel f.

WEXOG

WEXOG writes calculated industrial quantities to the NEMS exogenous variable array. Before assigning values to the NEMS variables, the module computes total industrial fuel consumption quantities. These values are then calibrated or benchmarked to the SEDS estimates for each data (history) year, and they thereafter are calibrated to the STEO forecast estimates. The calibration factors are multiplicative for all fuels that have consumption values greater than zero and are additive otherwise.

The equation for total industrial electricity consumption is below. Similar equations are used for all other fuels. Where appropriate, the summands include refinery consumption and oil and natural gas consumption, as follows:[32]

$$BMAIN_f = TQMAIN_f + QELRF \tag{63}$$

where

$BMAIN_f$ = total (industrial and refinery) consumption of fuel f (electricity);

$TQMAIN_f$ = IDM consumption of fuel f (electricity); and

$QELRF$ = refinery consumption of fuel f (electricity).

The equation for total industrial natural gas consumption is given as follows:

$$BMAIN_{f,s,o} = TQMAIN_f + QNGRF + CGOGQ_{sg} + CGOGQ_{og} \tag{64}$$

where

$BMAIN_f$ = consumption of fuel f (natural gas);

$TQMAIN_f$ = consumption of fuel f (natural gas);

$QNGRF$ = consumption of natural gas from refining;

$CGOGQ_{sg}$ = consumption of natural gas from cogeneration of electricity for sales to the grid in enhanced oil recovery, input from the Hydrocarbon Supply Module (HSM); and

[32] Consumption of electricity and fuels for the production of ethanol is calculated in the Liquid Fuels Market Module and consumption of electricity for the processing of oil shale is calculated in the Hydrocarbon Supply Module.

$CGOGQ_{og}$ = consumption of natural gas from cogeneration of electricity for own use in enhanced oil recovery, input from the HSM.

Total industrial consumption for other fuels is calculated similarly. The fuels that correspond to each fuel index f in BMAIN (Table 8).

Table 8. BMAIN indices and fuels in the Industrial Demand Module

Index	Fuel
1	electricity
2	hydrogen feedstock
3	natural gas—core (from process and assembly and buildings module components)
4	natural gas—noncore (from boiler, steam, and cogeneration module components)
5	natural gas—feedstock
6	natural gas—lease and plant fuel
7	steam coal
8	met coal
9	net coke coal imports
10	residual fuel
11	distillate
12	propane for heat and power
13	HGL feedstock
14	motor gasoline
15	still gas
16	petcoke
17	asphalt and road oil
18	lubes and waxes
19	petrochemical feedstock (naphtha feedstock)
20	kerosene
21	other petroleum feedstock
22	other petroleum
23	hydrogen for heat and power

Source: Industrial Demand Module

Regional SEDS benchmark factors are calculated as follows:

$$SEDSBF_{f,d} = \frac{\sum_d SEDS4_{f,d}}{BMAIN_f} \tag{65}$$

where

$SEDSBF_{f,d}$ = current SEDS data year benchmark factors by fuel f and census division d;

$SEDS4_{f,d}$ = current SEDS data year consumption for census division d, aggregated to the census region level by fuel f; and

$BMAIN_f$ = total industrial consumption of fuel f.

SEDS benchmark factors are then multiplied by the total industrial consumption value as follows:

$$BENCH_f = SEDSBF_f * BMAIN_f \tag{66}$$

where

$BENCH_{y,f}$ = benchmarked total industrial consumption of fuel f.

STEO benchmark factors are calculated as follows:

$$STEOBF_f = \frac{STEO_f}{\sum_f \sum_r BENCH_{f,r}} \tag{67}$$

where

$STEOBF_f$ = STEO benchmark factor, which equals each fuel's share of the total SEDS benchmarked industrial consumption, by fuel f (note that these factors are applied after SEDS data years);

$STEO_f$ = STEO forecast industrial consumption by fuel f for each STEO forecast year; and

$BENCH_{f,r}$ = benchmarked total industrial consumption by fuel f and census division r.

The STEO factors are applied to the SEDS industrial benchmarked consumption values as follows:

$$FinalBENCH_f = STEOBF_f * BENCH_f \tag{68}$$

To avoid a break in the series after the last STEO projection year, the STEO benchmark factors are incrementally decreased to one (no effect) over 12 years beginning in the first year after the last STEO projection year.

The benchmark factor for renewable fuels are computed similarly.

Benchmarked consumption values are then passed into the appropriate variables for reporting to NEMS. The following equation calculates consumption of electricity, and the equations for other fuels are similar:

$$QELIN_d = BENCH_{elec} * SEDSHR_{elec,d} \tag{69}$$

where

$QELIN_d$ = industrial consumption of electricity in census division d;

$BENCH_{elec}$ = benchmarked consumption of electricity; and

$SEDSHR_{elec,d}$ = SEDS share of electricity in census division.

Consumption of total renewable fuels is calculated by summing the consumption totals for the individual renewable fuel sources as follows:

$$QTRIN_d = QHOIN_d + QGEIN_d + QBMIN_d + QMSIN_d + QSTIN_d + QPVIN_d + QWIIN_d \tag{70}$$

where

$QTRIN_d$ = total industrial consumption of renewable fuels in census division d;

$QHOIN_d$ = industrial consumption of hydropower in census division d;

$QGEIN_d$ = industrial consumption of geothermal in census division d;

$QBMIN_d$ = industrial consumption of biomass in census division d;

$QMSIN_d$ = industrial consumption of municipal solid waste in census division d.

$QSTIN_d$ = industrial consumption of solar thermal in census division d;

$QPVIN_d$ = industrial consumption of photovoltaic in census division d;

$QWIIN_d$ = industrial consumption of wind in census division d; and

RDBIN

RDBIN is called by the main industrial subroutine ISEAM on model runs after the first model year. This subroutine reads the previous year's data from the binary files. The previous year's values are assigned to lagged variables for price, value of output, and employment. The previous year's UECs, TPC coefficients, price elasticities, and intercepts are read into the variables for initial UEC, TPC, price elasticity, and intercept. Process-specific data are read into either a lagged variable or an initial estimate variable. Three cumulative variables are calculated in this subroutine for future use. A cumulative output variable, a cumulative UEC, and a cumulative production variable are computed for each fuel and process step.

MODCAL

MODCAL performs like the main industrial subroutine ISEAM in all years after the first model year. In subsequent years, data from the input files do not need to be read; however, UECs and TPC coefficients must be adjusted to reflect the new model year, whereas the first model year uses only initial estimates of these values. MODCAL calls the following subroutines: PRODFLOW_PAPER, PRODFLOW_STEEL, CALPROD, CALCSC, CEMENT_INDUSTRY, ALUMINUM_INDUSTRY, GLASS_INDUSTRY, IRONSTEEL_INDUSTRY, PAPERPULP_INDUSTRY, CALPATOT, CALBYPROD, CALBTOT, PPIS_BSC, CALGEN, PCOGGEN, CALBSC, CALSTOT, BENCHMECS, INDTOTAL, NATTOTAL, and CONTAB. Similar to the functioning of ISEAM, the subroutines NATTOTAL and CONTAB are called only after the last region for an industry has been processed.

CALPROD

CALPROD determines the throughput for production flows for the process and assembly component for industries that are not process flow industries. Existing old and middle vintage production is reduced by applying a retirement rate of capital. The retirement rate is posited to be a positive function of energy prices, as follows:

$$RetirePriceFactor = \frac{Pricerat_y^{RetireBeta}}{\left(1 + \ Pricerat_y^{RetireBeta}\right)} \tag{71}$$

$$RetireRate_s = 2 * RetirePriceFactor * ProdRetr_s \tag{72}$$

where

$RetirePriceFactor$ = TPC price factor, ranging from 0 (no price effect) to 2 for retirements;

$Pricerat_y$ = ratio of current year average industrial energy price to base year price;

$RetireBeta$ = parameter of logistic function, currently specified as 2 for retirements;

$RetireRate_s$ = retirement rate, after accounting for energy price increases, for step s; and

$ProdRetr_s$ = default retirement rate for step s.

Production throughput for the existing capacity in an industry and step is calculated:

$$PRODCUR_{old,s,y} = \left(PRODCUR_{old,s,y-1} + IDLCAP_{old,s,y-1}\right) * \left(1 - RetireRate_{s,y-1}\right) \quad (73)$$

where

$PRODCUR_{old,s,y}$ = existing production for process step s for old vintage and year y; and

$IDLCAP_{old,s}$ = idle production at process step s for old vintage and year y.

If the initial UEC is in physical units, the value of output for the current year is multiplied by the fixed ratio of physical units to the value of output calculated in the first model year, as follows:

$$PRODX = PHDRAT * PRODVX \quad (74)$$

where

$PRODX$ = value of output in physical units in base year;

$PHDRAT$ = ratio of physical units to value of output (by industry but not region) in base year; and

$PRODVX$ = output in dollars in the base year.

If the initial UEC is in dollar units, then the current year's value of output is used to determine total production throughput. Total production throughput is calculated by determining new capacity requirements at each process step so as to meet final demand changes and replace retired capacity. This calculation is complicated because retirement rates of some steps differ, as do the process flow rates of old and new capacity. In addition, several process steps may jointly provide output for one or more downsteps. The solution to the problem is simplified by formulating the process flow relationships as input-output coefficients as described in the Leontief Input-Output Model (as described in Chiang, *Fundamental Methods of Mathematical Economics*, pp. 123-131). In this model, the output of a process step can either be a final demand or used as input to another process step. The objective is to determine the mix of old and new productive capacity at each process step such that all final demands are met. In this case, the final demand is the industry output.

The following definitions are provided to illustrate the problem:

A = input or output coefficient matrix with final demand as the first column and the production steps as the other columns. The coefficients are the values in the PRODFLOW array, placed in the array according to the IPASTP step definitions;

I = identity array;

D = final demand vector, but only the first element is nonzero (D_1 is equivalent to $PRODX$); and

X = vector of productive capacity needed to meet the final demand, based on **A** and **D** (**X** is equivalent to PRODCUR).

The input-output model is written as follows:

$$\left(\boldsymbol{I} - \boldsymbol{A_y}\right) * \boldsymbol{X_y} = \boldsymbol{d_y} \tag{75}$$

X is obtained by pre-multiplying both sides by the inverse of (**I-A**):

$$\boldsymbol{X_y} = (\boldsymbol{I} - \boldsymbol{A_y})^{-\boldsymbol{1}} * \boldsymbol{d_y} \tag{76}$$

Because the **A** coefficients for old and new capacity differ, there are two such arrays: $\mathbf{A_{old}}$ and $\mathbf{A_{new}}$. The corresponding technology matrices are $(\mathbf{I} - \mathbf{A_{old}})$ and $(\mathbf{I} - \mathbf{A_{new,y}})$.

Likewise, $\mathbf{X_{old}}$ and $\mathbf{X_{new,y}}$ are distinguished to account for old and new productive capacity. However, to incorporate the retirement calculation, the base year productive capacity will be referred to as $\mathbf{X_{old}}$, and the portion of that capacity that survives to a given year is called $\mathbf{X_{surv,y}}$. The portion that is retired is called $\mathbf{X_{ret}}$. Therefore, total productive capacity ($\mathbf{X_{tot}}$) is given by the following:

$$\mathbf{X_{tot,y}} = \mathbf{X_{surv,y}} + \mathbf{X_{new,y}} \tag{77}$$

or

$$\mathbf{X_{tot,y}} = \mathbf{X_{old}} - \mathbf{X_{ret,y}} + \mathbf{X_{new,y}} \tag{78}$$

$\mathbf{X_{old}}$ is defined in the base year as follows:

$$(\mathbf{I} - \mathbf{A_{old}}) * \mathbf{X_{old}} = \mathbf{d_{ibyr}} \tag{79}$$

$$\mathbf{X_{old}} = (\mathbf{I} - \mathbf{A_{old}})^{-\mathbf{1}} * \mathbf{d_{ibyr}} \tag{80}$$

$\mathbf{X_{new,y}}$ is defined as the cumulative capacity additions in year y since the base year.

A set of retirement rates, **R**, is defined for each producing step. The final demand step need not have a designated retirement rate. Retired capacity is given by the following:

$$\mathbf{X_{ret}} = \mathbf{X_{old}} * (\mathbf{1} - \mathbf{R})^{(y-ibyr)} \tag{81}$$

$$\mathbf{X_{surv}} = \mathbf{X_{old}} - \mathbf{X_{ret}} \tag{82}$$

The final demand that can be met by the surviving capacity is given by the following:

$$\mathbf{d_{orig,y}} = (\mathbf{I} - \mathbf{A_{old}}) * \mathbf{X_{surv,y}} \tag{83}$$

The remaining demand must be met by new capacity, such that the following condition holds:

$$(\mathbf{I} - \mathbf{A_{old}}) * \mathbf{X_{surv,y}} + (\mathbf{I} - \mathbf{A_{new}}) * \mathbf{X_{new,y}} = \mathbf{d}_{\mathrm{y}} \tag{84}$$

where $\mathbf{X_{new,year}}$ is the cumulative additions to productive capacity since the base year. $\mathbf{X_{new,year}}$ can be determined by solving the following system:

$$(\mathbf{I} - \mathbf{A_{new}}) * \mathbf{X_{new,y}} = \mathbf{d}_{\mathrm{y}} - (\mathbf{I} - \mathbf{A_{old}}) * \mathbf{X_{surv,year}} \tag{85}$$

Therefore, the following equation holds:

$$\mathbf{X_{new,y}} = (\mathbf{I} - \mathbf{A_{new}})^{-1} * \left(\mathbf{d_{year}} - (\mathbf{I} - \mathbf{A_{old}}) * \mathbf{X_{surv,y}}\right) \tag{86}$$

The last equation is used to implement the approach in the module. The solution is found by calling a matrix inversion routine to determine $(\mathbf{I} - \mathbf{A_{new}})^{-1}$, followed by calls to intrinsic matrix multiplication functions to solve for $\mathbf{X_{new}}$. As a result, the amount of actual code to implement this approach is minimal.

CALBYPROD

We run the IDM assuming that all byproduct fuels are consumed before the purchasing of any fuels. The CALBYPROD subroutine calculates the energy savings resulting from byproduct fuel consumption for the location on the technology possibility curve (TPC) based on the current year's industry production and the previous year's industry production for each process step, fuel, and vintage. The TPC for biomass byproducts is assumed to be a positive function of energy prices. For all other industries that do not include iron and steel and pulp and paper, the UEC remains unchanged. The iron and steel and pulp and paper industries do not use this subroutine because submodule CHP uses specific code.

$$TPCRate_{v,f,s,y} = 2^{*}TPCPriceFactor_y * BYPCSC_{v,f,s} \tag{87}$$

where

$TPCRate_{v,f,s,y}$	= is the TPC rate for vintage v, fuel f, step s, and year y, for biomass byproduct fuels;
$TPCPriceFactor_y$	= is calculated on page 55; and
$BYPCSC_{v,f,s}$	= initial byproduct TPC for vintage v, fuel f, and step s.

CALBYPROD calculates the rate of byproduct energy produced for each process step, fuel, and vintage as shown in the following equation. This value is based on the previous year's rate of production and the current energy savings for each vintage:

$$BYPINT_{v,f,s} = \left(BYPINTLag_{v,f,s}\right) * \exp(TPCRate_v) \tag{88}$$

where

$BYPINT_{v,f,s}$ = rate of byproduct energy production (or UEC) for byproduct fuel f at process step s for vintage v;

$BYPINTLag_{v,f,s}$ = lagged rate of byproduct energy production for byproduct fuel f at process step s for vintage v; and

$TPCRate_v$ = TPC multiplier on TPC rate due to energy price increases for vintage v, calculated on page 55.

The UEC for middle vintage is a weighted average (by production) of the previous year's energy savings for new vintage and the previous year's energy savings for middle vintage, as shown by the following:

$$BYPINT_{mid,f,s} = \left[\frac{\left(PRODLag_{mid,f,s} \; * \; BYPINTLag_{mid,f,s}\right) + \left(PRODLag_{new,s} * \; BYPINTLag_{new,f,s}\right)}{\left(PRODLag_{mid,s} \; + \; PRODLag_{new,s}\right)}\right] * \exp(TPCRate_{old}) \quad (89)$$

where

$PRODLag_{new,s}$ = previous year's production from new vintage capacity at process step s;

$BYPINTLag_{new,f,s}$ = lagged rate of byproduct energy production for byproduct fuel f at process step s for new vintage;

$PRODLag_{mid,s}$ = previous year's production from middle vintage capacity at process step s;

$BYPINTLag_{mid,f,s}$ = lagged rate of byproduct energy production for byproduct fuel f at process step s for middle vintage; and

$TPCRate_{old}$ = TPC multiplier on TPC rate due to energy price increases for old vintage; calculation is shown on page 55.

The rate of byproduct fuel production is used to calculate the quantity of byproduct energy produced by multiplying total production at the process step by the production rate, as shown in the following:

$$BYPQTY_{v,f,s} \; = \; PRODCUR_{v,s} \; * \; BYPINT_{v,f,s} \quad (90)$$

where

$BYPQTY_{v,f,s}$ = byproduct energy production for byproduct fuel f at process step s for vintage v;

$PRODCUR_{v,s}$ = production at process step s for vintage v; and

$BYPINT_{v,f,s}$ = rate of byproduct energy production for byproduct fuel f at process step s for vintage v.

Note that $PRODCUR_{v,s}$ is production by a vintage at a step and is not fuel-specific. The rate of byproduct fuel production is then converted from millions of Btu to trillions of Btu. Byproduct fuel production is subdivided into three categories: main fuels, intermediate fuels, and renewable fuels.

Byproduct production for each group of fuels is determined by summing byproduct production over the individual process steps for each fuel and vintage as shown below for main byproduct fuels. The equations for intermediate and renewable fuels are similar, as follows:

$$ENBYM_{f,v,s} = \sum_{s=1}^{MPASTP} BYPQTY_{v,f,s} \tag{91}$$

where

$ENBYM_{f,v,s}$ = byproduct energy production for main byproduct fuel f for vintage v and process step s; and

$MPASTP$ = number of process steps.

CALCSC

CALCSC computes UEC for all industries. The current UECs for the old and new vintages are calculated as the product of the previous year's UEC and a factor that reflects the assumed rate of intensity decline over time and the impact of energy price changes on the assumed decline rate.

For all industries except the process flow industries,[33] the IDM capital stock is grouped into three vintages: old, middle, and new. The old vintage consists of capital in production in the base year and is assumed to retire at a fixed rate each year. Middle vintage capital is that which is added from the base year through the year *Year*-1, where *Year* is the current projection year. New capital is added for the projection years when existing production is less than the output projected by the MAM. Capital stock added during the projection period is retired in subsequent years at the same rate as the pre-base year capital stock.

CALCSC starts by calculating the REIs for years after the base year as follows:

$$REI_{v,f,s} = \left(1 + BCSC_{v,f,s}\right)^{(ijumpcalyr - ibyr)} \tag{92}$$

where

$REI_{v,f,s}$ = the relative energy intensity of fuel f for vintage v and step s;

$BCSC_{v,f,s}$ = default TPC for old and new vintage v for each fuel f and step s;

$ijumpcalyr$ = the last model year; and

$ibyr$ = the base IDM year.

[33] The process flow industries are cement and lime, aluminum, glass, iron and steel, and pulp and paper.

After the base year, the price-adjusted REI is defined as:

$$REI\_Adj_{v,f,s} = 1 + (REI_{v,f,s} - 1) * \left(1 - \frac{1}{1 + \left[alpha1_s * \frac{\max\left((y - ibyr2 - Tshift_{f,s}), 0\right)}{Tmid_{f,s} - ibyr2 - Tshift_{f,s}} + alpha2_s * \max\left((TPCratio - 1), 0\right)\right]^{beta1_s}}\right) \tag{93}$$

where

$REI\_Adj_{v,f,s}$ = price-adjusted REI of fuel f for vintage v and step s;

$alpha1_s$ = time-dependence coefficient, set to 1;

$alpha2_s$ = price-dependence coefficient, set to 1;

$Tshift_{f,s}$ = logistic curve time shift, set to 4;

$Tmid_{f,s}$ = logistic curve inflection point, set to 15;

$beta1_s$ = logit parameter, set to 2;

$TPCratio$ = result of a function that returns the ratio of fuel prices relative to the base year; and

$ibyr2$ = the year before the IDM base year.

The dynamic TPC is then defined as:

$$TPCrate_v = \min\left(\frac{REI\_Adj_{v,f,s}}{REI\_Adj\_lag_{v,f,s}}, 1\right) \tag{94}$$

where

$TPCrate$ = dynamic TPC (accounting for the effect of increased energy prices); and

$REI\_Adj\_lag_{v,f,s}$ = REI from the previous year.

The annual UEC for the old and new vintage is calculated as the product of the previous year's UEC and the TPC, which reflects the assumed rate of intensity decline over time and the impact of energy price changes on the assumed decline rate:

$$Enpint_{v,f,s,y} = EnpintLag_{v,f,s,y} * TPCRate_v \tag{95}$$

where

$Enpint_{v,f,s}$	= unit energy consumption of fuel f at process step s for vintage v (for old or new vintages only); and
$EnpintLag_{v,f,s}$	= previous year's energy consumption of fuel f at process step s for vintage v.

The UEC for middle vintage is calculated as the ratio of cumulative UEC to cumulative production for all process steps and industries:

$$ENPINT_{mid,f,s} = \left[\frac{\left(PRODLag_{mid,f,s} * ENPINTLag_{mid,f,s}\right) + \left(PRODLag_{new,s} * ENPINTLag_{new,f,s}\right)}{\left(PRODLag_{mid,s} + PRODLag_{new,s}\right)}\right] \tag{96}$$

where

$ENPINT_{mid,f,s,y}$	= is the UEC of process step s for fuel f of middle vintage capacity;
$PRODLag_{mid,s}$	= is the previous year's production from middle vintage capacity at process step s;
$ENPINTLag_{mid,f,s}$	= is the lagged rate of energy consumption for fuel f at process step s for middle vintage capacity;
$PRODLag_{new,s}$	= is the previous year's production from new vintage capacity at process step s; and
$ENPINTLag_{new,f,s}$	= is the lagged rate of energy consumption for fuel f at process step s for new vintage capacity.

CALBSC

This subroutine revises boiler fuel shares each year based on changes in fuel prices since the base year. The fuel sharing is calculated using a logit formulation. The fuel shares apply only to conventional boiler fuel use. Cogeneration fuel shares are assumed to be constant and are based on data from Form EIA-860. Base year boiler fuel use is obtained by subtracting cogeneration fuel use from total MECS indirect fuels (this calculation is done in subroutine MECSLESS860). Waste and byproduct fuels are excluded from the logit calculation because they are assumed to be consumed first. The boiler fuel sharing equation for each industry is as follows:

$$ShareFuel_{i,f,y} = \frac{\left(P_{f,y}^{\propto_f} \beta_f\right)}{\sum_{f=1}^{3} P_{f,y}^{\propto_f} \beta_f} \tag{97}$$

where

$ShareFuel_f$	= boiler fuel share for industry i and fuel f in year y;

P_f = fuel price relative to the base year price for fuel f with fuel premium index applied;[34]

$\propto_f$ = sensitivity parameter for fuel f, default value is -2.0; and

β_f = efficiency for boiler fuel fired by fuel f.

To accommodate the preference for natural gas industrial boilers (both new and replacements) due to the implementation of the boiler MACT, price premium indices were applied to the fuels coal (1.33) and oil (1.17) relative to natural gas (1.00).

The fuels are limited to coal, petroleum, natural gas, and electricity because they are the only fuels used in substantial quantities in industrial boilers. Base year boiler shares for individual petroleum products are calculated explicitly to obtain exact estimates of these fuel shares from the aggregate petroleum fuel share calculation. The byproduct fuels are consumed before the quantity of purchased fuels as explained in the WEXOG section on page 71.

CALBSC also allows for the expansion of electric boilers over time. By 2050, 40% of the coal-fired boilers and 20% of the natural-gas-fired boilers are assumed to be replaced by electric boilers. Electric boilers are deployed according to a logistic (or S-shaped) curve.

Non-manufacturing subroutines

AGRICULTURE INDUSTRY: Subroutine AGTPC

The AGTPC subroutine calculates the consumption of energy in the agriculture industries by further subdividing consumption in each subindustry based on the equipment in which the energy is used: off-road vehicles, which are trucks, tractors, and other specialty vehicles; buildings, which require lighting and temperature control; and other equipment, which covers a variety of both common (for example, pumps) and specialty (for example, cotton gins) equipment used in the various types of agricultural production.

Vehicle intensity is calculated as a weighted average using the existing stock of light-, medium-, and heavy-duty trucks. The miles per gallon (mpg) measured by fuel from the TDM is indexed to decline over time. The TPC for agricultural vehicles is therefore estimated in the module as follows:

$$VEH\_Index_{f,y} = \min\left(\frac{1}{10}\left(\frac{Trk_{Intens_{f,y}}}{Trk_{Intens_{f,y-1}}} - 1\right), TPC\_Limit\right) \tag{98}$$

$$Trk\_Intens_{f,y} = \frac{1}{\sum_s TFR\_TRK\_FAS\_T_{s,f,y}} \sum_s \frac{TFR\_TRK\_FAS\_T_{s,f,y}}{TFR\_FTMPG_{s,f,y}} \tag{99}$$

where

[34] NESCAUM, Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers, January 2009.

$VEH\_Index_{f,y}$ = index used to calculate subindustry TPC for vehicles for fuel f in year y;

$Trk\_Intens_{f,y}$ = average truck energy intensity for fuel f in year y;

TPC_Limit = the upper constraint on the TPC, set to -0.001 to ensure a minimum level of improvement;

$TFR\_TRK\_FAS\_T_{s,f,y}$ = existing truck stock for fuel f in year y for truck size s; and

$TFR\_FTMPG_{s,f,y}$ = truck mpg for fuel f in year y for truck size s.

We calculate building energy intensity using an index of heating, lighting, and building shells retrieved from the Commercial Demand Module (CDM) for warehouses because this building type is most similar to the types of buildings used in agricultural production. The shares for these three energy users are based on data analysis commissioned by EIA[35] and shown in Table 9. The TPC for agricultural buildings is estimated in the module as follows:

$$BLD\_Index_{r,1,y} = \min\left(\left(\frac{WHSE_{HeatIndex_{r,f,y}}}{WHSE_{HeatIndex_{r,f,y-1}}} - 1\right), TPC\_Limit\right) \tag{100}$$

$$BLD\_Index_{r,2,y} = \min\left(\left(\frac{WHSE\_LightIndex_{r,f,y}}{WHSE\_LightIndex_{r,f,y-1}} - 1\right), TPC\_Limit\right) \tag{101}$$

$$BLD\_Index_{r,3,y} = \min\left(\left(\frac{WHSE\_ShellIndex_{r,f,y}}{WHSE\_ShellIndex_{r,f,y-1}} - 1\right), TPC\_Limit\right) \tag{102}$$

where

$BLD\_Index_{r,\mathrm{k},y}$ = index, before weighting for heating equipment (k=1), lighting equipment (k=2), or building shells (k=3), used to calculate subindustry TPC for buildings for region r in year y;

$WHSE\_HeatIndex_{r,f,y}$ = composite of warehouse energy consumption in heating equipment retrieved from the CDM in region r for fuel f in year y;

$WHSE\_LightIndex_{r,f,y}$= composite of warehouse energy consumption in lighting equipment retrieved from the CDM in region r for fuel f in year y; and

$WHSE\_ShellIndex_{r,f,y}$ = composite of warehouse energy consumption in building shells retrieved from the CDM in region r for fuel f in year y.

Irrigation intensity is computed much the same way as the building intensity, relying on

[35] SRA International, Report on the Analysis and Modeling Approach to Characterize and Estimate Fuel Use by End-Use Applications in the Agriculture and Construction Industries, unpublished report prepared for the U.S. Energy Information Administration, March 2011.

$WHSE\_VentIndex_{r,f,y}$ instead, as follows:

$$IRR\_Index_{r,f,y} = \min\left(\left(\left(\frac{WHSE_{VentIndex_{r,f,y}}}{WHSE_{VentIndex_{r,f,y-1}}}\right) - 1\right), TPC\_Limit\right) \tag{103}$$

where

$IRR\_Index_{r,f,y}$ = irrigation intensity index in census region r for fuel f in year y; and

$WHSE\_VentIndex_{r,f,y}$ = composite of warehouse energy consumption in building vents retrieved from the CDM in census region r for fuel f in year y.

Table 9. Building weights for technology possibility curve index by fuel in the Commercial Demand Module

Equipment type	Heating	Lighting	Shell
electricity	0.25	0.25	0.50
natural gas	0.25	0	0.75
distillate	0.25	0	0.75
propane	0.25	0	0.75
motor gasoline	0.25	0	0.75

Source: Commercial Demand Module Documentation

Other equipment is directly indexed to other warehouse equipment using a fourth composite retrieved from the CDM[36].

CONSTRUCTION INDUSTRY

The construction industry does not have a specialized subroutine, and is modeled the same way as the other end-use industries.

COAL INDUSTRY: Subroutine COALTPC

The COALTPC subroutine calculates the consumption of energy in the coal mining industry by further subdividing consumption in each subindustry based on the equipment in which the energy is used: off-road vehicles, which are trucks, tractors, and other specialty vehicles; various equipment, which encompasses lighting, heating, and ventilation; and grinding equipment.

The most significant determinant of energy use in the coal mining sector is the distinction between underground and surface mining, and so aggregate production values of underground versus surface are obtained from the Coal Market Module (CMM) for use in COALTPC.

The amount of fuel (*f*) demanded by the Coal Mining industry in a given year (*y*) is calculated as follows:

$$Q_{f,y} = COALMN_y * UEC_{f,y} \tag{104}$$

[36]Details of the three warehouse energy consumption variables can be found in U.S. Energy Information Administration, Documentation of the Commercial Demand Module (CDM), DOE/EIA-M066(2013), Washington, DC, July 2011, pg. 16−39.

where

$Q_{f,y}$ = consumption of fuel f in year y for coal mining;

$COALMN_y$ = the value of coal mining output in year y, supplied by the MAM; and

$UEC_{f,y}$ = the unit energy consumption of fuel f in year y for coal mining.

The IDM calculates this quantity for each of the four census regions. The UEC changes from year to year according to the value of the TPC, as follows:

$$UEC_{f,y} = UEC_{f,y-1} * \left(1 + TPC_{f,y}\right) \tag{105}$$

where the TPC indicates the marginal change in energy intensity from the previous year.

The TPC is calculated as the weighted average of three indices representing the marginal change in three factors: equipment efficiency, the share of underground mining, and labor productivity. These indices are described in detail below.

Factor indices

Equipment

Heating, lighting, and ventilation

The weighted equipment index is based on the fuel in question and is determined using proxy measures derived from the CDM, the TDM, and results of the cement submodule in the IDM.

From the CDM, measures are based on the weighted average efficiency of heating, lighting, and ventilation services provided to the warehouse building type (type 10 in the CDM). Definitions and calculations are the same as in the AGTPC subroutine on page 82.

Vehicle energy intensity

From the TDM, the freight truck submodule generates (at the national level) fuel economy estimates for three classes of truck: medium, medium-heavy, and heavy. The contribution to the TPC is based on stock-weighted average fuel economy estimates of the truck population. The average energy intensity is the inverse of the average fuel economy and the marginal change in vehicle energy intensity is defined and computed by fuel (*f*) and year (*y*) exactly as in AGTPC subroutine on page 82.

Grinding equipment

From the results of the cement submodule, the average efficiency of raw grinding equipment is extracted to use as a proxy for changes in the energy intensity of mining equipment. This factor is only applied to the TPC for electricity, as follows:

$$Raw\_Grind\_Eff_y = \frac{\sum_{Tech} Elec\_Use\_Rpt_{Tech,y}}{\sum_{Tech} Tot\_ProdG_{Tech,y}} \tag{106}$$

where

$Elec\_Use\_Rpt_{Tech,y}$ = reported electricity consumption for cement grinding, by grinder technology $Tech$ and year y; and

$Tot\_ProdG_{Tech,y}$ = total grinding output, by grinder $Tech$ and year y.

The weighted equipment index is then calculated. For electricity, the calculation is as follows:

$$Wt\_EQP\_Index_{f,y} = \left[\frac{Raw\_Grind\_Eff_y}{Raw\_Grind\_Eff_{y-1}} - 1.0\right] * Elec\_Weight_{Grind} + \left[\frac{WHSE\_LightIndex_y}{WHSE\_LightIndex_{y-1}} - 1.0\right] * Elec\_Weight_{Light} + \left[\frac{WHSE\_VentIndex_y}{WHSE\_VentIndex_{y-1}} - 1.0\right] * Elec\_Weight_{Vent} \quad (107)$$

For other fuels, the calculation is as follows:

$$Wt\_EQP\_Index_{f,y} = \left[\frac{WHSE\_HeatIndex_{f,y}}{WHSE\_HeatIndex_{f,y-1}} - 1.0\right] * NonEl\_Weight_{Heat,f} + VEH\_Index_{f,y} * NonEl\_Weight_{Vehicle,f} \quad (108)$$

where the various weighting factors are input from an exogenous data file.

Table 10. Energy weights for mining equipment in the Industrial Demand Module

Elec_Weight		NonEl_Weight		
			Share	
Function	**Share**	**Fuel**	**Heat**	**Vehicle**
grinding	20%	natural gas	80%	20%
lighting	20%	distillate	70%	30%
		gasoline	0%	100%
ventilation	60%	coal	100%	0%
		resid	100%	0%

Source: U.S. Energy Information Administration

Surface and underground mining share

This component of the TPC reflects changes in the regional share of coal produced from underground mines. Surface and underground production is reported by the CMM and provided to the IDM for this calculation. Production is aggregated from the 14 coal regions to the 4 census regions, as follows:

$$CL\_Surface_{r,y} = \sum_{cr} PMTS_{r,y,cr} \tag{109}$$

$$CL\_Underground_{r,y} = \sum_{cr} PMTD_{r,y,cr} \tag{110}$$

where PMTS and PMTD represent the tons of coal produced on the surface and underground, respectively (from the CMM), and the 14 coal production regions are mapped to the 4 census regions as follows:

Table 11. Census region and coal region mapping from the Coal Market Module

Census region	Coal regions
1	1
2	2, 3, 6
3	4, 5, 7
4	8–14

Source: Coal Market Module

The fraction of annual production from underground mines is then given as follows:

$$Under\_Share_{r,y} = \frac{CL\_Underground_{r,y}}{\left(CL\_Underground_{r,y} + CL\_Surface_{r,y}\right)} \tag{111}$$

The marginal change in that share is given as follows:

$$Under\_Index_{r,y} = \frac{Under\_Share_{r,y}}{Under\_Share_{r,y-1}} - 1.0 \tag{112}$$

Labor productivity

Labor productivity is derived from one of the data input files, CLUSER.txt, employed by the CMM. Each of the production regions has projections of productivity by coal type; these are used to construct a production-weighted average productivity projection mapped to the census regions: $CL\_L\_Prod_{r,y,Surf}$, for census region r, year y, and mine type $Surf$ (1 = surface, 2 = underground).

The productivity index is given as follows:

$$L\_Prod\_Index_{r,y,Surf} = \quad 1.0 - \frac{CL\_L\_Prod_{r,y,Surf}}{CL\_L\_Prod_{r,y-1,Surf}} \tag{113}$$

TPC calculation

The collective TPC by fuel type and region may now be explicitly calculated as follows:

$$TPC_{r,f,y} = TPC\_Weight_{1,f} * Wt\_EQP\_Index_{f,y}$$
$$+ TPC\_Weight_{2,f} * Under\_Index_{r,y}$$
$$+ TPC\_Weight_{3,f} * Under\_Share_{r,y} * L\_Prod\_Index_{r,1,y}$$

$$+ TPC\_Weight_{3,f} * (1.0 - Under\_Share_{r,y}) * L\_Prod\_Index_{r,2,y} \quad (114)$$

where the number index represents the weight associated with either the equipment (1), the underground coal production index (2), or the underground coal share (3).

The factor weights by region and fuel for mining equipment are as follows, based on analyst judgment:

Table 12. Technology possibility curve (TPC) mining equipment component weights by region for the Industrial Demand Module

$TPC\_Weight_{1,f}$	Electricity	Natural gas	Distillate	Gasoline	Coal	Resid
Region 1	70%	85%	90%	100%	70%	90%
Region 2	70%	85%	90%	100%	70%	90%
Region 3	70%	85%	90%	100%	70%	90%
Region 4	70%	85%	90%	100%	70%	90%

Source: U.S. Energy Information Administration

The weights for the two remaining factors are calculated as follows:

$$TPC\_Weight_{2,f} = \frac{(1.0 - TPC\_Weight_{1,f})}{2} \quad (115)$$

$$TPC\_Weight_{3,f} = 1.0 - (TPC\_Weight_{1,f} + TPC\_Weight_{2,f}) \quad (116)$$

In other words, the difference between 1.0 and the equipment weighting factor is divided between the other two weights.

OIL AND NATURAL GAS MINING: Subroutine OGSMTPC

The OGSMTPC subroutine calculates the consumption of energy in the oil and natural gas extraction industry with the major exception of lease and plant fuel, which is natural gas fuel used for any purpose at the lease (extraction) site and fuel used in natural gas processing plants (lease and plant fuel is modeled in the Natural Gas Market Module). All other fuels (electricity, residual fuel oil, distillate, motor gasoline, and other petroleum) are covered by OGSMTPC, as well as that natural gas that is not used in lease and plant fuel (that is, in natural gas liquids fractionators).

Energy consumption in this sector is largely driven by the number of wells drilled (related to oil and natural gas volumes) and their productivity.

The amount of fuel (*f*) demanded by the oil and gas mining industry in year (*y*) is calculated as follows:

$$Q_{f,y} = OGMN_y * UEC_{f,y} \quad (117)$$

where

$Q_{f,y}$ = consumption of fuel f in year y for oil and natural gas production;

$OGMN_y$ = the value of domestic onshore oil and natural gas production in year y, supplied by the MAM; and

$UEC_{f,y}$ = the unit energy consumption of fuel f in year y for oil and natural gas production.

The IDM calculates this quantity for each of the four census regions. The UEC (by fuel *f*) changes from year to year (year *y-1* to year *y*) according to the value of the TPC, as follows:

$$UEC_{f,y} = UEC_{f,y-1} * (1 + TPC_{f,y}) \tag{118}$$

where the TPC indicates the marginal change in energy intensity from the previous year. The TPC is calculated as the weighted average of three indices representing the marginal change in three factors: vehicle energy intensity, the regional productivity of oil and natural gas wells, and trends in the share of drilling that result in dry wells. Each of these components is described below.

Factor indices for oil and natural gas mining

Vehicle energy intensity

As noted in earlier sections, the freight truck submodule generates fuel economy estimates for three classes of truck. The contribution to the TPC is based on stock-weighted average fuel economy estimates of the truck population, and the marginal change in vehicle energy intensity is defined and computed by fuel (*f*) and year(*y*) exactly as in *AGTPC* subroutine on page 82.

Productivity factors

The Hydrocarbon Supply Module (HSM) produces estimates of onshore oil and natural gas production for six production regions (PR) and seven product types (K) related to fuel types, as follows (the variable PROD_Wt is a measure of the relative difficulty of extraction, used in subsequent calculations):

Table 13. Relative difficulty of extraction of oil and natural gas, as calculated in the Hydrocarbon Supply Module

K	Product type	PROD_Wt
1	conventional oil	1.0
2	enhanced oil recovery	3.0
3	conventional shallow natural gas	1.0
4	conventional deep natural gas	1.0
5	tight gas	3.0
6	shale gas	2.0
7	coal bed methane	3.0

Source: Hydrocarbon Supply Module

The output from the production regions is first mapped to the corresponding census regions and converted from million barrels of oil and trillion cubic feet of natural gas to trillion Btu, as follows:

$$OG\_Prod_{K,r,y} = \left[\sum_{PR=1}^{7} OGREGPRD_{PR,K,y} * OGSM\_Map_{PR,r}\right] * Convert_{Tech} \tag{119}$$

where

$OG\_Prod_{K,r,y}$ = production of product K in region r in year y;

$OGREGPRD_{PR,K,y}$ = regional production by production region *PR*, and fuel type *K*, from HSM;

$OGSM\_Map_{PR,r}$ = regional mapping factors, based on the geographic areas of states in each census region *r*, provided in the table below; and

$Convert_{Tech}$ = conversion factor for oil (Tech=1) and natural gas (Tech=2).

Table 14. Hydrocarbon Supply Module and census region mapping

	HSM production region						
OGSM_Map	**Northeast**	**Gulf Coast**	**Midcontinent**	**Southwest**	**Rocky Mountains**	**Northern Great Plains**	**West Coast**
Census region	**1**	**2**	**3**	**4**	**5**	**6**	**7**
1	22.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	38.0%	0.0%	71.3%	0.0%	15.5%	15.5%	0.0%
3	39.1%	100.0%	28.7%	57.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	43.0%	84.5%	84.5%	100.0%

Source: U.S. Energy Information Administration

The share of total production represented by oil is then calculated as follows:

$$Oil\_Share_{r,y} = \frac{\sum_{K=1}^{2} OG\_Prod_{K,r,y}}{\sum_{K=1}^{7} OG\_Prod_{K,r,y}} \tag{120}$$

In addition, the oil and natural gas production factor, $OG\_ProdFac_{K,r,y}$, representing the weighted average difficulty of extraction by fuel K, region r, and year y, is calculated as follows:

$$OG\_ProdFac_{r,y} = \frac{\sum_K OG\_Prod_{K,r,y} * PROD\_Wt_K}{\sum_K OG\_Prod_{K,r,y}} \tag{121}$$

where K is 1 and 2 for oil and 3−7 for natural gas (see Table 14. Hydrocarbon Supply Module and census region mapping). The productivity index is then calculated as follows:

$$Prod\_Index_{r,y} = Oil\_Share_{r,y} * \left[\frac{OG\_ProdFac_{Tech=1,r,y}}{OG\_ProdFac_{Tech=1,r,y-1}} - 1.0\right] + \left(1.0 - Oil\_Share_{r,y}\right) * \left[\frac{OG\_ProdFac_{K=2,r,y}}{OG\_ProdFac_{K=2,r,y-1}} - 1.0\right] \tag{122}$$

Dry well index

Another factor affecting the TPC is the share of drilling that produces dry wells. Growth in this factor is assumed to correlate with increased energy required for overall extraction. The data for successful and dry wells are obtained from the HSM and are mapped from the seven production regions (*PR*) to the four census regions (*r*), as follows:

$$Success\_Well_{K,r,y} = \sum_{PR=1}^{7} ogsrl48_{PR,K,y} * ogwellsl48_{PR,K,y} * OGSM\_Map_{PR,r} \tag{123}$$

$$Dry\_Well_{K,r,y} = \sum_{PR=1}^{7} \left(1.0 - ogsrl48_{PR,K,y}\right) * ogwellsl48_{PR,K,y} * OGSM\_Map_{PR,r} \tag{124}$$

$$Total\_Well_{K,r,y} = Success\_Well_{K,r,y} + Dry\_Well_{K,r,y} \tag{125}$$

where

$ogsrl48_{PR,K,y}$ = share of successful wells by production region *PR*, product type *K*, and year y;

$ogwellsl48_{PR,K,y}$ = total wells drilled, by region and type; and

$OGSM\_Map_{PR,r}$ = regional mapping factors, based on the geographic areas of states in each region, described above.

The production-weighted average dry well percentage by census region is then calculated as follows:

$$Wtd\_OG\_WellFac_{r,y} = \frac{\frac{\sum_K Dry\_Well_{K,r,y}}{\sum_K Total\_Well_{K,r,y}} * OG\_Prod_{K,r,y}}{\sum_K OG\_Prod_{K,r,y}} \tag{126}$$

The well index is expressed as the change in this factor from the previous year:

$$Well\_Index_{r,y} = Wtd\_OG\_WellFac_{r,y} - Wtd\_OG\_WellFac_{r,y-1} \tag{127}$$

TPC calculation

The collective TPC by fuel type and region may now be explicitly calculated as follows:

$$TPC_{f,r,y} = TPC\_Fac\_Wt_{f,1} * VEH\_Index_{f,y} + TPC\_Fac\_Wt_{f,2} * Prod\_Index_{r,y} + TPC\_Fac\_Wt_{f,3} * Well\_Index_{r,y} \tag{128}$$

where

$TPC\_Fac\_Wt_{f,i}$ = ad hoc weighting factors within each fuel type that indicate the influence of each of the index factors (i=1 is for the vehicle index, i=2 is for the productivity index, and i=3 is for the dry well index), shown in Table 15.

Table 15. Technology possibility curve (TPC) factor weights by fuel *(TPC_Fac_Wt)*

Fuel	Vehicle index	Productivity index	Dry well index
electricity	0.0	0.8	0.2
natural gas	0.5	0.4	0.1
distillate	0.5	0.4	0.1
gasoline	0.5	0.4	0.1
renewables	0.0	0.8	0.2
residual fuel oil	0.0	0.8	0.2

Sources: Hydrocarbon Supply Module and Transportation Demand Module

OTHER MINING: Subroutine OTH_MINTPC

The OTH_MINTPC subroutine calculates the consumption of energy for mining metals and minerals, which constitute all other mining subsectors. As in the COALTPC subroutine, energy usage for grinding equipment used in this sector is evolved parallel to grinding equipment in the cement industry. In addition, like the COALTPC subroutine, the distinction between surface and subsurface mining is made, which governs a large portion of energy consumption patterns in this industry.

The amount of fuel (*f*) demanded by the other mining (metals and minerals) industry in year (*y*) is calculated as follows:

$$Q_{f,y} = OTHMN_y * UEC_{f,y} \tag{129}$$

where $OTHMN_y$ represents the value of metals and non-metals mining production, supplied by the MAM. The IDM calculates this quantity for each of the four census regions. The UEC changes from year to year according to the value of the TPC, as follows:

$$UEC_{f,y} = UEC_{f,y-1} * (1 + TPC_{f,y}) \tag{130}$$

where the TPC indicates the marginal change in energy intensity in year *y* from the previous year *y-1*. The TPC is calculated as the weighted average of three indices representing the marginal change in two factors: equipment efficiency and the labor productivity of surface mining, obtained from the CMM. The TPC is further subdivided between metal mining and non-metal mining, in recognition of their different characteristics. These indices are described in detail below.

Other mining macroeconomic split

Total mining shipments are reported at the regional level by the MAM, but the metals and non-metals components are available only at the national level. Accordingly, it is necessary to infer what share of regional mining output consists of metals. At present, the national metals share is included as a data statement, but it can be extracted from the MAM as follows:

$$MetlShr_y = \frac{R2122R\_1_y}{R2122R\_1_y + R2123R\_1_y} \tag{131}$$

where

$R2122R\_1_y$ = annual value of metals production from the MAM, by year *y*; and

$R2123R\_1_y$ = annual value of non-metals production from the MAM, by year *y*.

This share is regionalized by reference to the 2006 Census of Employment and Wages (CEW), which provides estimates of employment in the mining industries, by state. We used the following data to determine what fraction of each region's mining output may be attributed to metals. The parameter Reg_MetlShr is in the input file shown in Table 16 and is held static.

Table 16. Metal and non-metal shares by census region

Census region	Normalized share Reg_MetlShr
1	0.0%
2	21.0%
3	2.0%
4	77.0%

Source: U.S. Census Bureau
Note: These factors are used in the final calculation of the technology possibility curve, below.

Factor indices for other mining

Labor productivity

Labor productivity is defined and calculated on page 8787.

Equipment

The weighted equipment index is calculated similarly to that shown starting on page 86.

Grinding equipment

From the results of the cement submodule on page 95, the average efficiency of raw grinding equipment per year, or $Raw\_Grind\_Eff_y$, is extracted to use as a proxy for changes in the energy intensity of mining equipment.

Vehicle energy intensity

The freight truck submodule generates fuel economy estimates for three classes of truck. The contribution to the TPC is based on stock-weighted average fuel economy estimates of the truck population, and the marginal change in vehicle energy intensity is defined and computed by fuel (*f*) and year (*y*) exactly as in *AGTPC* subroutine on page 82.

The weighted equipment index is then calculated for metals and non-metals separately.

For electricity (metals mining), the calculation is as follows:

$$Wt\_Met\_EQP\_Index_{f,r,y} = \left[\frac{Raw\_Grind\_Eff_y}{Raw\_Grind\_Eff_{y-1}} - 1.0\right] * Elec\_Met\_Weight_{Grind}$$

$$+\left[\frac{WHSE\_LightIndex_{r,y}}{WHSE\_LightIndex_{r,y-1}}-1.0\right]*Elec\_Met\_Weight_{Light}$$

$$+\left[\frac{WHSE\_VentIndex_{r,y}}{WHSE\_VentIndex_{r,y-1}}-1.0\right]*Elec\_Met\_Weight_{Vent} \quad (132)$$

where the difference in the calculation is in the relative weights ascribed to grinding, lighting, and pumping (through its proxy, ventilation). The calculation for non-metals is similar, using weights for nonmetallic mining (Table 22).

Table 17. Electric equipment weights

	Variable	Grinding	Lighting	Pumping
metals	Elec_Met_Wt	0.2	0.2	0.6
non-metals	Elec_NM_Wt	0.6	0.2	0.2

Sources: Commercial Demand Module (for lighting and pumping), Industrial Demand Module–cement submodule (for grinding)

For other fuels (metals), the calculations are as follows:

$$Wt\_Met\_EQP\_Index_{f,y}=\left[\frac{WHSE\_HeatIndex_{f,r,y}}{WHSE\_HeatIndex_{f,r,y-1}}-1.0\right]*Elec\_Met\_Weight_{Heat,f}$$

$$+VEH\_Index_{f,y}*NonEl\_Met\_Weight_{Vehicle,f} \quad (133)$$

where the current weighting factors for metals and non-metals are identical. The calculation for non-metals is similar, using weights for non-metal mining. The submodule assigns the same weights to the two variables to make subsequent, user-specified changes easier to implement.

Table 18. Non-electric equipment weights (applies to metals and non-metals)

	Natural gas	Distillate	Gasoline	Coal	Residual
heating	80%	70%	0%	100%	100%
vehicles	20%	30%	100%	0%	0%

Source: Commercial Demand Module and Transportation Demand Module

TPC calculation

The collective TPC by fuel type *f* and region *r* may now be explicitly calculated as follows:

$$TPC_{r,f,y}=\begin{bmatrix}TPC\_Met\_Wt_{\mathrm{r,1,f}}*Wt\_Met\_EQP\_Index_{r,y}\\ +TPC\_Met\_Wt_{\mathrm{r,2,f}}*L\_Prod\_Index_{r,y}\end{bmatrix}*MetlShr_y*Reg\_MetlShr_r$$
$$+\begin{bmatrix}TPC\_NM\_Wt_{r,1,f}*Wt\_NM\_EQP\_Index_{r,y}\\ +TPC\_NM\_Wt_{r,2,f}*L\_Prod\_Index_{r,y}\end{bmatrix}*\left(1.0-MetlShr_y*Reg\_MetlShr_r\right) \quad (134)$$

where the TPC equipment index weights for both metals and non-metals are provided in Table 12, based on analyst judgment.

Table 19. Technology possibility curve equipment component weights for metals and non-metals, by region

Region	Electricity	Natural gas	Distillate	Gasoline	Coal	Residual
1	70%	85%	90%	100%	70%	90%
2	70%	85%	90%	100%	70%	90%
3	70%	85%	90%	100%	70%	90%
4	70%	85%	90%	100%	70%	90%

Source: U.S. Energy Information Administration

The non-equipment (that is, labor productivity) index weights are then calculated as follows:

$$TPC\_Met\_Wt_{r,2,f} = 1.0 - TPC\_Met\_Wt_{r,1,f} \quad (135)$$

As with the non-electric equipment weights, above, the factors are identical across regions and for metals and non-metals mining. This explicit separation of the two mine types in the code provides an easily adaptable structure for testing and scenario development.

Specialized submodules for process flow industries

Common technical choice subroutines for the process flow industries

For the iron and steel and paper industries, common subroutines are used where possible when calculating energy use, needed capacity, and technology choice. Because industries differ in process steps and products, common subroutines are not always possible.

- Tech_Step: the main process flow subroutine that reports energy consumption by fuel for each technology, needed productive capacity, and technology chosen for that capacity. Tech_Step calls these subroutines. Tech_Step is also used in the cement and lime, glass, iron and steel, pulp and paper, and aluminum submodules.
- Step_Capacity: computes needed capacity for each process step based on product demand and retirement rates.
- Logit_Calc: determines which technologies are chosen for each process step.

Subroutine Step_Capacity

For each process step, demand for production is defined by the sum of regional PRODCUR elements. After establishing the output of a given step, we must determine whether additional processing capacity will be needed. In each year following the base year, incremental additions to capacity are based on the following assumptions:

- Baseline capacity is retired at a linear rate over a fixed time frame (read in from ironstlx.xlsx).
- Production demand in excess of surviving baseline capacity will be met with replacement equipment.
- Equipment acquired after the base year will retire according to a logistic decay function.

Calculating surviving and needed capacity are the first two steps.

$$Surviving\_Cap_{j,y} = BaseCap_{j,y} + Surv\_Incr\_Adds_{j,y} \tag{136}$$

$$Needed\_Cap_{j,y} = \mathrm{MAX}\left(SumProdCur_{j,y} - Surviving\_Cap_{j,y}, 0\right) \tag{137}$$

where, for the current year y and step j,

$BaseCap_{j,y}$	= surviving baseline production capacity;
$Surv\_Incr\_Adds_{j,y}$	= surviving incremental capacity added before the current year y;
$Needed\_Cap_{j,y}$	= incremental production capacity required;
$SumProdCur_{j,y}$	= total production capacity required to meet demand (calculation details are on page 123); and
$Needed\_Cap_{j,y}$	= incremental production capacity required.

Surviving capacity has two components: base capacity and previously added capacity. Surviving baseline capacity is calculated as follows:

$$BaseCap_{j,y} = BaseCap_{j,y-1} - \left[\frac{BaseCap_{j,BaseYr}}{BaseCap\_Life}\right] \tag{138}$$

where

$BaseCap_{\ BaseYr}$	= initial value of baseline production capacity for base year $BaseYr$; and
$BaseCap\_Life$	= assumed lifetime of baseline capacity (read in from ironstlx.xlsx).

For equipment added to meet incremental demand in previous years, the calculation is as follows:

$$Surv\_Incr\_Adds_{j,y} = \sum_{ii=BaseYr}^{y-1} Surviving_{ii} * \left[\sum_{Tech=1}^{MaxTech} Added\_Cap_{j,Tech,ii}\right] \tag{139}$$

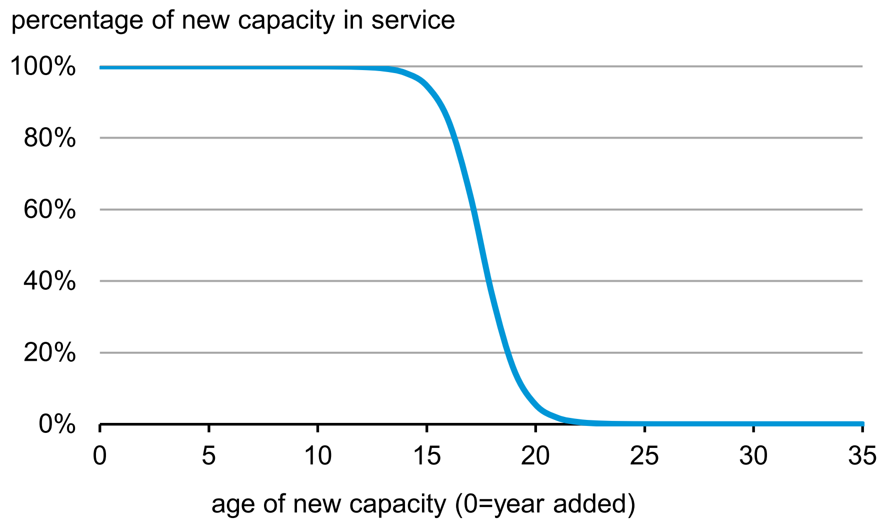
$$Surviving_{ii} = \frac{1}{1 + \exp\left[-Calib * \left(1.0 - \left[\frac{2.0 * (ii - 1)}{Lifetime}\right]\right)\right]} \tag{140}$$

where

$Surv\_Incr\_Adds_{j,y}$	= cumulative surviving added capacity for step j in year y;
$Added\_Cap_{j,Tech,ii}$	= capacity added for step j, technology $Tech$, in year ii.
$Surviving_{ii}$	= the retirement function for capacity added in year ii;
$Lifetime$	= assumed lifetime of added capacity (read in from ironstlx.xlsx); and
$Calib$	= calibration constant for the survival curve (read in from ironstlx.xlsx).

The survival function determines the share of capacity added in a given year that survives to the current year (Figure 11).

Figure 11. Example of new capacity survival function



Source: U.S. Energy Information Administration, based on parameters in ironstlx.xlsx

After establishing the required additions to production capacity, $Needed\_Cap_i$ must be allocated among competing technologies.

Subroutine Tech_Step

Tech_Step determines the relative shares of each technology used in the newly added capacity for each process step in each of the process-flow industries using a multinomial logit model that assesses the economics of competing technologies. Each alternative technology has identifying characteristics, in this case, the capital cost, operations and maintenance (O&M) cost, fuel use, steam demand, and CO_2 emissions associated with the production of a thousand metric tons of output. First, the model calculates equipment utility:

$$
\begin{aligned}
U_{j,Tech,y} = {} & \beta_1 * Tot\_Cost_{Tech} \\
& + \beta_2 * \left(\sum_f Fuel\_Use_{j,Tech,f,y} * Fuel\_Cost_{f,y} + Steam\_Use_{j,Tech} \right) \\
& + \beta_3 * \left(CO2Emiss_{j,Tech} * CO2\_Cost_y \right) \\
& + Alpha_{j,Tech} * Decay\_Fctr_{j,y} + Scale\_Factr
\end{aligned} \tag{141}
$$

where

$U_{j,Tech,y}$ = equipment utility, referred to in the code as *logit_comp* for step j, technology $Tech$, and year y;

β_i = scaling coefficient for each technology attribute i, referred to in the code as *calibrationc*;

$Alpha_{j,Tech}$ = alternative-specific constant (ASC) for step j and technology $Tech$, that ensures initial shares agree with historical values, described further below;

$Decay\_Fctr_{j,y}$ = alpha-decay factor for step j and year y, that reduces the ASC to zero over time, described below;

$Scale\_Fctr$ = dynamically-calculated scaling factor that ensures that the FORTRAN calculations will not go out of bounds and crash the program;

$Tot\_Cost_{j,Tech}$ = equipment fixed costs per thousand metric tons of output for step j and year y;

$Fuel\_Use_{j,Tech}$ = energy intensity of each fuel used by technology $Tech$ in step j, in MMBtu/thousand metric tons;

$Fuel\_Cost_{f,y}$ = price of energy, in $/MMBtu; for the associated fuel f in year y;

$Steam\_Use_{j,Tech}$ = steam service demand for technology $Tech$ in year y, in gigajoules (GJ) per thousand metric tons of output;

$CO2Emiss_{j,Tech}$ = CO_2 emissions for technology $Tech$ in step j, in thousand metric tons per thousand metric ton of output; and

$CO2\_Cost_y$ = CO_2 emissions cost in year y, in $/thousand metric tons, exogenously specified.

The market shares of the competing production technologies are then calculated as follows:

$$Tech\_Shares_{j,Tech,y} = \frac{\exp\,(U_{j,Tech,y})}{\sum_{Tech}\exp\,(U_{j,Tech,y})} \tag{142}$$

Alpha, the alternative-specific constant, is a scaling factor that ensures that initial shares of technology match the exogenously specified baseline shares. This scaling is done through a recursive process in the module's base year, in which all alphas are iteratively replaced as follows:

$$Alpha_{j,Tech,z} = Alpha_{j,Tech,z-1} + \ln\left(\frac{ExogShare_{j,Tech}}{Tech\_Shares_{j,Tech,BaseYr}}\right) \tag{143}$$

where

$Alpha_{j,Tech,z}$ = alternative specific constant for step j, technology $Tech$, and iteration z;

$ExogShare_{\ Tech}$ = exogenously-specified baseline share for the technology Tech; and

$Tech\_Shares_{j,Tech,BaseYr}$ = calculated baseline share for step j, technology $Tech$, at base year $BaseYr$, using specified coefficients.

This process continues until all alphas converge to within a specified tolerance; specifically, when the magnitude of change between iterations falls below 0.001, or $(Alpha_{j,Tech,z} - Alpha_{j,Tech,z-1})$. < 0.001. The alphas are subsequently held constant.

The decay factor reduces the effect of this constant over time so that the incremental additions of technology are increasingly determined by their attributes. The decay function is expressed as follows:

$$Decay\_Fctr_y = \exp\left(\frac{-alpha\_decay_1 * (y - ibyr) * ln\,(2)}{alpha\_decay_2}\right) \tag{144}$$

where *alpha_decay*$_1$ and *alpha_decay*$_2$ are user-specified parameters that determine the rate of decay and *ibyr* is the model base year.

The total production, by technology, is given by the following:

$$Tot\_Prod\_Tech_{j,Tech,y} = BaseCap_j * Base\_Tech\_Share_{j,Tech} + Surv\_Added\_Cap_{j,Tech,y} + Add\_Cap_{j,y} * Tech\_Shares_{j,Tech,y} \tag{145}$$

where

$BaseCap_j$ = surviving capacity for step j from the base year;

$Base\_Tech\_Share_{Tech}$ = base year shares of production technology $Tech$;

$Add\_Cap_{j,y}$ = capacity added to step j in current year y;

$Tech\_Shares_{j,Tech,y}$ = shares of technology $Tech$ added to step j in current year y; and

$$Surv\_Added\_Cap_{j,Tech,y} = \sum_{ii=BaseYr}^{y-1} Surviving_{ii,y} * Added\_Cap_{j,Tech,ii} \tag{146}$$

where

$Surv\_Added\_Cap_{j,Tech,y}$ = surviving added capacity for step j, technology $Tech$, and year y;

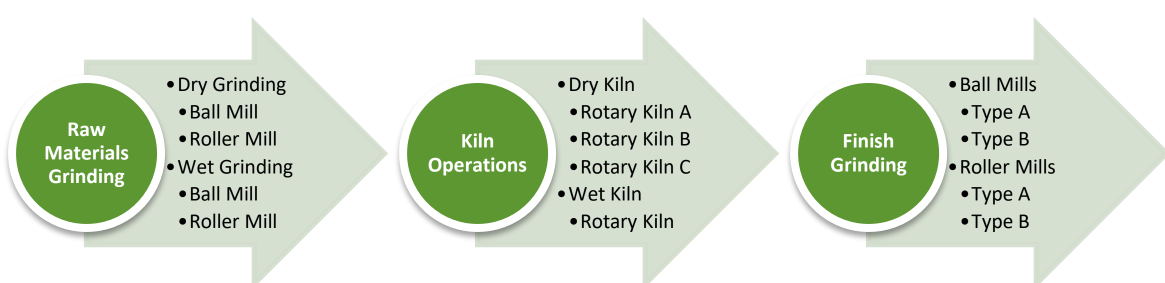
$Surviving_{ii,y}$ = is defined on page 96; and

$Added\_Cap_{j,Tech,i}$ = is defined on page 96.

CEMENT INDUSTRY

Figure 12 shows a detailed process flow diagram (PFD) for cement manufacturing. Raw materials containing calcium, silicon, aluminum, iron, gypsum, and small amounts of other ingredients are crushed and ground in ball mills, roller mills, or both. The mining and transport of raw materials to the plant site are excluded in the cement submodule because these operations are modeled in a separate module of NEMS. Internal submodule calculations are in metric units.

Figure 12. Cement industry detailed process flow in the cement submodule

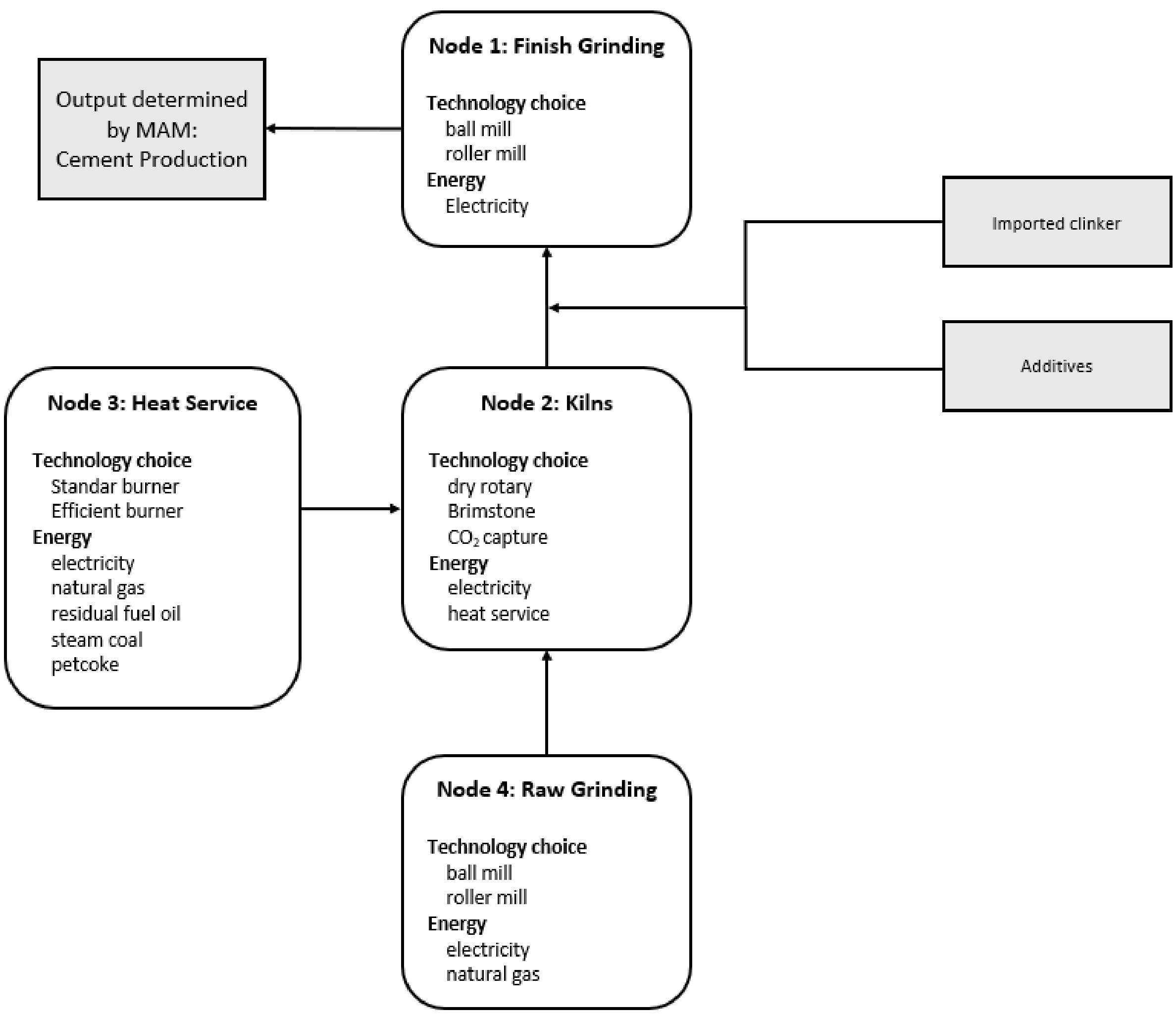


Source: U.S. Energy Information Administration

The raw materials are ground dry (dry processing) or combined with water to form slurry (wet processing). Wet grinding reduces grinding energy consumption, but it increases the energy consumption for evaporating the added water. The crushed raw materials enter a kiln (often preceded by a pre-heater system) and are heated to ~2,700°F/1,500°C. U.S. kilns are commonly fired by coal, with natural gas and residual oil as a starter or backup fuel. Alternative fuels such as waste are also used as supplementary fuels. The kiln converts the raw materials mixture into clinker, which is then cooled rapidly to prevent further chemical changes. The cooled clinker is blended with additives and ground into a fine powder that is cement. The cement may be bagged or transported in bulk to retail stores and commercial users.

Because of the chemistry of cement production, mass flows through each major unit operation will not be the same. For this reason, the calculation of mass flows through each unit operation will begin at the end of the PFD—that is, the annual production of cement in the finish grinding operation.

Figure 13. Cement submodule process steps in the Industrial Demand Module



Source: U.S. Energy Information Administration

TECH_STEP (Node 1)

The cement portion of the TECH_STEP subroutine represents cement production capacity requirements for the IDM.

The output of the finish grinding node is the total quantity of cement shipments (in thousand metric tons) in a given year, as follows:

$$Output_y = Output\_IBYR2 * \left[\frac{OUTIND_{11,y}}{CEMENTIBYR}\right] \tag{147}$$

where

$Output_y$ = physical quantity of cement shipments, in thousands of metric tons, projected for the cement industry;

$Output\_IBYR2$ = physical quantity of cement shipments, in thousands of metric tons in the base year, as reported by the U.S. Geological Survey;

$OUTIND_{11,y}$ = gross value of shipments for the cement industry (IDM industry code of 11) for the nation in the current projection year, as determined by the MAM; and

$CEMENTIBYR$ = gross value of shipments for the cement industry for the nation in the base year, as determined by MAM.

The output requirements of the finish grinders are reduced by including additives and imported clinker, following the grinding step:

$$Grinding\_Tonnes_y = Output_y \; * \; (1.0 - (cm\_import\_clink + cm\_add)) \tag{148}$$

where

$Grinding\_Tonnes_y$ = quantity of output from the finish grinding step in year y, in thousands of metric tons;

cm_add = percentage of additives, which is currently held constant at 9.6%; and

cm_import_clink = percent of clinker that is imported, which is currently held constant at 1.1%

Cement production in the base year represents existing baseline capacity, which is allocated among the four competing types of finish grinders as follows:

$$BaseCapF_{Tech} = Grinding\_Tonnes * Tech\_Share_{Tech} \tag{149}$$

where

$BaseCapF_{Tech}$ = initial baseline capacity, by equipment tech;

$Grinding\_Tonnes_y$ = quantity of output from the finish grinding step, in thousands of metric tons; and

$Tech\_Share_{Tech}$ = initial allocation of finish grinding capacity.

For each year following the base year, incremental additions to finish grinding capacity are based on the following assumptions:

- Baseline capacity is retired at a linear rate over a fixed period (read in from ironstlx.xlsx).
- Production demand in excess of surviving baseline capacity will be met with replacement equipment.
- Equipment acquired after the base year will retire according to a logistic function.

We calculate the baseline capacity that survives, the survival of any added incremental capacity, and needed capacity all in subroutine Step_Capacity (page 95). The survival function determines the share of needed capacity added in a given year that survives to the current model year (Figure 11).

After establishing the required additions to finish grinding capacity, the CEMENT_INDUSTRY submodule allocates the current model year's added capacity among competing technologies in subroutine Logit_Calc (page 97).

KILN_CAPACITY (Node 2)

Process heat service required by the kilns is addressed in this node. Wet process and dry process capacity are treated differently because the wet process is obsolete and retiring wet capacity is not replaced. Accordingly, the heating systems associated with the wet process are assumed to be retired at the same rate as the kilns they service.

Kilns provide the clinker for the finish grinding step, so total kiln output and capacity are linked to the previous node. Historically, a certain fraction of the material proceeding to the finish grinding step consists of imported clinker and other additives. This process reduces the needed capacity of kilns, as follows.

Baseline kiln capacity (that is, output in the base year) is distributed between wet and dry processes, and it is further allocated among different kiln technologies according to historical production shares as follows:

$$Wet\_Process_{Baseyear} = Process\_OutputK_{Baseyr} * pWet \tag{150}$$

$$Dry\_Process_{Baseyear} = Process\_OutputK_{Baseyr} * (1 - pWet) \tag{151}$$

where

$Wet\_Process_{Baseyr}$ = wet process capacity in base year;

$pWet$ = historical share of wet process output, 1.8%, in the base year;

$Dry\_Process$ = dry process capacity in base year; and

$Process\_OutputK$ = total output from cement kilns, in thousands of metric tons.

For the base year, storing of values for subsequent computations occurs as follows:

$$Wet\_RotaryIBYR_{Baseyr} = Wet\_Rotary_{Baseyr} \tag{152}$$

$$Dry\_Rotary_{Tech,Baseyr} = Dry\_Process_{Tech,Baseyr} * Tech\_Share_{Tech,Baseyr} \tag{153}$$

$$Dry\_RotaryIBYR_{Tech,Baseyr} = Dry\_Rotary_{Tech,Baseyr} \tag{154}$$

where

$Tech\_Share_{Tech,Baseyr}$ = allocation shares of dry rotary kilns;

$Wet\_RotaryIBYR_{Baseyr}$ = wet process capacity in the base year; and

$Dry\_RotaryIBYR_{Tech}$ = dry process capacity, by equipment technology in the base year.

Baseline capacities in subsequent years are calculated using the formula on page 96.

The survival of any added incremental capacity is based on a logistic function, $New\_Cap\_ServK_i$, which is similar to $Surv\_Incr\_Adds_{j,y}$, described on page 96. The survival function determines the share of needed capacity added in a given year that survives to the current model year (Figure 11).

Next, any needed added incremental capacity, stored and retained by model year, for the current model year is determined by both surviving baseline and surviving incrementally added capacity as follows:

$$Needed\_Capacity_y = Process\_OutputK_y - Surviving\_Capacity_y \tag{155}$$

Calculation details for $Needed\_Capacity_y$ and $Surviving\_Capacity_y$ are described in subroutine Step_Capacity (page 95).

The use of the wet process is considered to be declining and is consequently not replaced by new, similar technologies. Because of different input process (for example, raw grinding) requirements associated with the wet process, it needs to be tracked separately, and retirements are accommodated by additions to dry process technology. Any added incremental capacities for dry rotary kilns are subsequently allocated to kiln type in the KILN_ALLOCATION subroutine.

New capacity is allocated in the CM_RAW_GRIND subroutine using a multinomial logit model, in which the characteristics of competing alternatives are assessed. Each alternative technology has identifying characteristics—in this case, the capital cost, O&M cost, fuel use, and particulate emissions associated with the production of a thousand metric tons of cement. These characteristics are extracted from the ironstlx.lsx input file, which contains detailed data for each component in the cement manufacturing process. Each multinomial logit model used in allocating equipment types is initially calibrated to provide the baseline shares of equipment. The annual market share for each new technology is calculated in subroutine Logit_Calc (page 97).

KILN_ALLOCATION (Node 2)

As noted above, all additional kiln capacity is expected to be provided by dry process kilns, and the allocation of incremental demand is governed by the characteristics of the competing dry-process technologies, based on a multinomial logit model. Each multinomial logit model used in allocating equipment types is initially calibrated to provide the baseline shares of equipment, as shown above.

After these market shares are applied to the incrementally added production capacity, coupled with the surviving production capacity from both the wet and dry process kilns, the heat demand in total cement kilns is determined as follows:

$$Heat\_Demand_y = \sum\nolimits_{Tech} Heat\_Req_{Tech,y} \tag{156}$$

where

$Heat\_Demand_y$ = total amount of heat demand, as expressed in gigajoules (GJ), to produce $Process\_OutputK$, as expressed in thousands of metric tons of clinker; and

$Heat\_Req_{Tech,y}$ = heating requirements, by kiln process technology based on clinker production and reported CIMS energy requirements.

The heat (that is, $Heat\_Req_{Tech,y}$) required to produce this output (expressed in GJ) is calculated separately for each process and subsequently totaled and passed to the CEMENT_INDUSTRY's subroutine BURNER_CAP, as the variable $Heat\_Demand$ and $Heat\_Req_{1,y}$ (that is, 1 index denotes heating requirement for wet process kilns).

The electricity used in wet process kilns is produced in a CHP system that also provides the required process heat service. Accordingly, these kilns are net producers of electricity, and this component of the electric energy requirement is expressed as a negative in the CEMENT_INDUSTRY submodule's output.

In the base year, the total process heat requirement, calculated in subroutine KILN_ALLOCATION, is allocated among the available burner types, determined as follows:

$$Heat\_Demand_y = \sum\nolimits_{Tech} Heat\_Req_{Tech,y} \tag{157}$$

$$Wet\_Heat_y = Heat\_Req_{1,\mathrm{y}} \tag{158}$$

$$Dry\_Heat\_Req_{\ y} = \sum_{Tech=2}^{numtech} Heat\_Req_{Tech,y} \tag{159}$$

where

$Heat\_Demand_y$ = total amount of heat demand, as expressed in gigajoules (GJ) of burner output, to produce $Process\_OutputK$, as expressed in thousands of metric tons of clinker;

$Heat\_Req_{Tech,y}$ = heating requirements, by kiln process $Tech$, based on clinker production and reported CIMS energy requirements—in other words, wet process is denoted as type 1;

Wet_Heat_y = heat demand for wet process kilns; and

$Dry\_Heat\_Req_y$ = total heat demand for dry process kilns.

For years after the base year, heat requirements for each technology are calculated similar to the function $Tot\_Prod\_Tech_{j,Tech,y}$ (page 99).

Wet process heating systems are treated differently, in that the allocation of boiler types remains static at base year shares because wet process kilns are considered as declining linearly in IDM projections.

The survival function determines the share of needed capacity added in a given year that survives to the current model year (Figure 11). Then any needed added incremental dry heating capacity, stored and retained by model year, for the current model year is determined by both surviving baseline and surviving incrementally added heating capacity as follows:

$$Needed\_Capacity_y = Dry\_Heat\_Req_y - Surviving\_Capacity_y \tag{160}$$

$Needed\_Capacity_y$ and $Surviving\_Capacity_y$ are calculated in subroutine Step_Capacity (page 95).

Table 20. Initial allocation of cement kiln burners

Type	Description	Initial share$_{Type,\ ibyr}$
natural gas 1	standard natural gas-fired burner	6.0%
natural gas 2	efficient natural gas-fired burner	17.4%
oil 1	standard oil burner	0.1%
oil 2	efficient oil burner	0.3%
coal	standard coal burner	36.5%
petroleum coke	standard petroleum coke burner	12.7%
other petroleum	other petroleum products burner	27.0%

Source: U.S. Energy Information Administration, estimated based on data from the Portland Cement Association.

CM_BURNER (Node 3)

As with the other nodes, needed capacity additions, yielding $Needed\_Capacity_y$, and $Surviving\_Capacity_y$ are calculated in subroutine Step_Capacity (page 95). The annual market share for each new technology is calculated in subroutine Logit_Calc (page 97). The model does not build new residual-oil-fired burners.

CM_RAW_GRIND (Node 4)

The clinker output from the kilns in Node 2 governs the required demand in the raw grinding step of the CEMENT_INDUSTRY submodule. The submodule treats the dry and wet processes separately. The quantity of material passing through the raw grinding step is calculated as follows:

$$Dry\_Process\_Out_y = Process\_OutputK_y - Wet\_Process_y \tag{161}$$

$$Raw\_Material_y = Dry\_Process\_Out_y * MassLoss \tag{162}$$

where

$Dry\_Process\_Out$ = quantity of clinker, in thousand metric tons, produced using dry process, as determined from Node 2;

$Process\_OutputK$	= total quantity of clinker, in thousand metric tons, produced as determined from Node 2;
$Wet\_Process_y$	= quantity of clinker, in thousand metric tons, produced using wet process, as determined from Node 2 by year *y*;
$Raw\_Material$	= raw material throughput for dry process, in thousands of metric tons; and
$MassLoss$	= mass loss ratio, set to 1.6.

Wet and dry process grinders have different characteristics and initial allocations (Table 21).

Table 21. Initial allocations of process grinders in the cement submodule

Type	**Description**	**Initial share**
dry process grinders		*Shares* $_{Type,ibyr}$
ball mill	dry raw grinding ball mill	43%
roller mill	dry raw grinding roller mill	57%

Source: SAIC, *Model Documentation Report: The U.S. Cement Industry*, unpublished data report prepared for the Office of Energy Analysis, U.S. Energy Information Administration, Washington, DC, August 2012.

As noted previously, wet process capacity is assumed to retire linearly, without replacement, and the demand for associated raw grinding services is directly linked to wet process clinker production. Surviving baseline capacity is computed in subroutine Step_Capacity (page 95).

The survival function determines the share of needed capacity added in a given year that survives to the current model year. An example is shown in in Figure 11 on page 97.

Next, any needed added incremental capacity, stored and retained by model year, for the current model year is determined by both surviving baseline and surviving incrementally added capacity as follows:

$$Needed\_Capacity_y = Raw\_Material_y - Surviving_{Capacity_y} \tag{163}$$

$Needed\_Capacity_y$ and $Surviving\_Capacity_y$ are calculated in subroutine Step_Capacity (page 95).

As with the other nodes, needed capacity additions, yielding $Needed\_Capacity_y$, and $Surviving\_Capacity_y$ are calculated in subroutine Step_Capacity (page 95). The annual market share for each new technology is calculated in subroutine Logit_Calc (page 97).

Cement process emissions calculations

Process emissions are significant during clinker production at cement plants. The IDM calculates process emissions for cement using a factor of 0.507 metric tons of CO_2 per metric ton of clinker.[37] These are tracked separately from combustion CO_2 emissions.

[37] Gibbs, Michael J., Peter Soyka, David Conneely, January 2001, *CO_2 Emissions from Cement Production*, Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories.

LIME INDUSTRY

Lime industry production and energy demand are also calculated in the cement industry submodules. Cement and lime energy shipments and energy consumption are reported together, although they are projected separately. The MAM estimates lime shipments. The cement submodule calculates lime UECs as a function of capital equipment used and updates capital equipment based on demand, capacity surviving, and new capacity.

Capacity determination

We assume lime production in the base year represents existing baseline. Lime demand is subsequently allocated among the three competing types of kilns. In the IDM base year, baseline capacity is equal to physical production:

$$Baseline\_Capacity\_IBYR = \ Demand\_IBYR \tag{164}$$

where

$Demand\_IBYR$	= physical lime production reported by U.S. Department of Interior, U.S. Geological Survey, for the base year; and
$Baseline\_Capacity\_IBYR$	= lime kiln capacity in the base year.

For years after the base year, the lime kiln capacity is determined from baseline retirements and computed as follows:

$$Baseline\_Capacity\_Lag = Baseline\_Capacity \tag{165}$$

$$Baseline\_Capacity = Baseline\_Capacity\_Lag - \left[\frac{Baseline\_Capacity\_IBYR}{Baselife}\right] \tag{166}$$

where

$Baseline\_Capacity\_Lag$	= previous year's lime kiln capacity;
$Baseline\_Capacity$	= surviving baseline kiln capacity;
$Baseline\_Capacity\_IBYR$	= initial lime kiln capacity in the base year; and
$Baselife$	= lifetime of baseline lime kiln capacity.

The survival function determines the share of needed capacity added in a given year that survives to the current model year. An example is shown in in Figure 11. As with the other nodes, surviving capacity and needed capacity additions, are calculated in subroutine Step_Capacity (page 95).

Table 22. Initial allocation of lime kilns, by fuel

Type	Description	Initial share $Technology\_Share_{Type}$
coal	rotary kiln: coal	73%
residual fuel oil	rotary kiln: residual fuel oil	14%
natural gas	vertical shaft kiln: natural gas	13%

Source: U.S. Energy Information Administration

In summary, each year following the base year incremental additions to kiln capacity are based on the following assumptions:

- Baseline capacity is retired at a linear rate over a fixed time frame.
- Production demand in excess of surviving baseline capacity will be met with replacement equipment.
- Equipment acquired after the base year will retire according to a logistic decay function.

After establishing the required additions of kiln capacity, the submodule allocates the projected new capacity ($Incr\_Adds_y$) among the competing technologies.

Capacity allocation

New capacity is allocated among technologies using a multinomial logit model, in which the characteristics of competing alternatives are assessed. The annual market share for each new technology is calculated in subroutine Logit_Calc (page 97).

The energy projected and then reported in the IDM for lime production is based on the kiln output and energy of each type of kiln and other process and assembly end-use activities, as reported in the CIMS data and latest MECS data. Partitioning of the national estimate of energy consumption in the lime industry into census regions occurs in the CALPATOT subroutine of IDM.

Lime process emissions calculations

Process emissions are also significant during lime production. The IDM calculates process emissions for lime using a factor of 0.751 metric tons of CO_2 per metric ton of lime[38]. These are tracked separately from combustion CO_2 emissions.

GLASS INDUSTRY

Glass is an inorganic product that is typically produced by melting a mixture of silica (sand), soda, and a calcium compound (usually lime). The desired metallic oxides that serve as coloring agents are added to this mixture. All industrial glass is manufactured through the following steps:

1. preparing the right mix of raw materials
2. melting and refining the raw materials

[38] Stork, Michiel, Wouter Meindertsma, Martijn Overgaag, Maarten Neelis, July 2014, *A Competitive and Efficient Lime Industry*, Cornerstone for a Sustainable Europe, The European Lime Association.

3. forming and finishing the molten glass into desired products

The mix of raw materials is based on the type of glass being manufactured and its desired properties and color. Melting varies in scale, temperature, and residence time, and it is typically carried out in tank melters. Forming is much more diverse considering the wide range of products from the glass industry. Some glass products require additional finishing processes.

Products manufactured by the U.S. glass industry span a broad range, including food and beverage containers, flat glass, windows for automobiles and buildings, video displays, cookware, leaded crystal, and light bulbs. In the glass submodule, these products are classified under four general categories—flat glass, container glass, blown glass, and fiberglass. Blown glass (also known as specialty glass) is the smallest of the four glass industry segments. The large diversity of products is accompanied by an equally large diversity of forming processes.

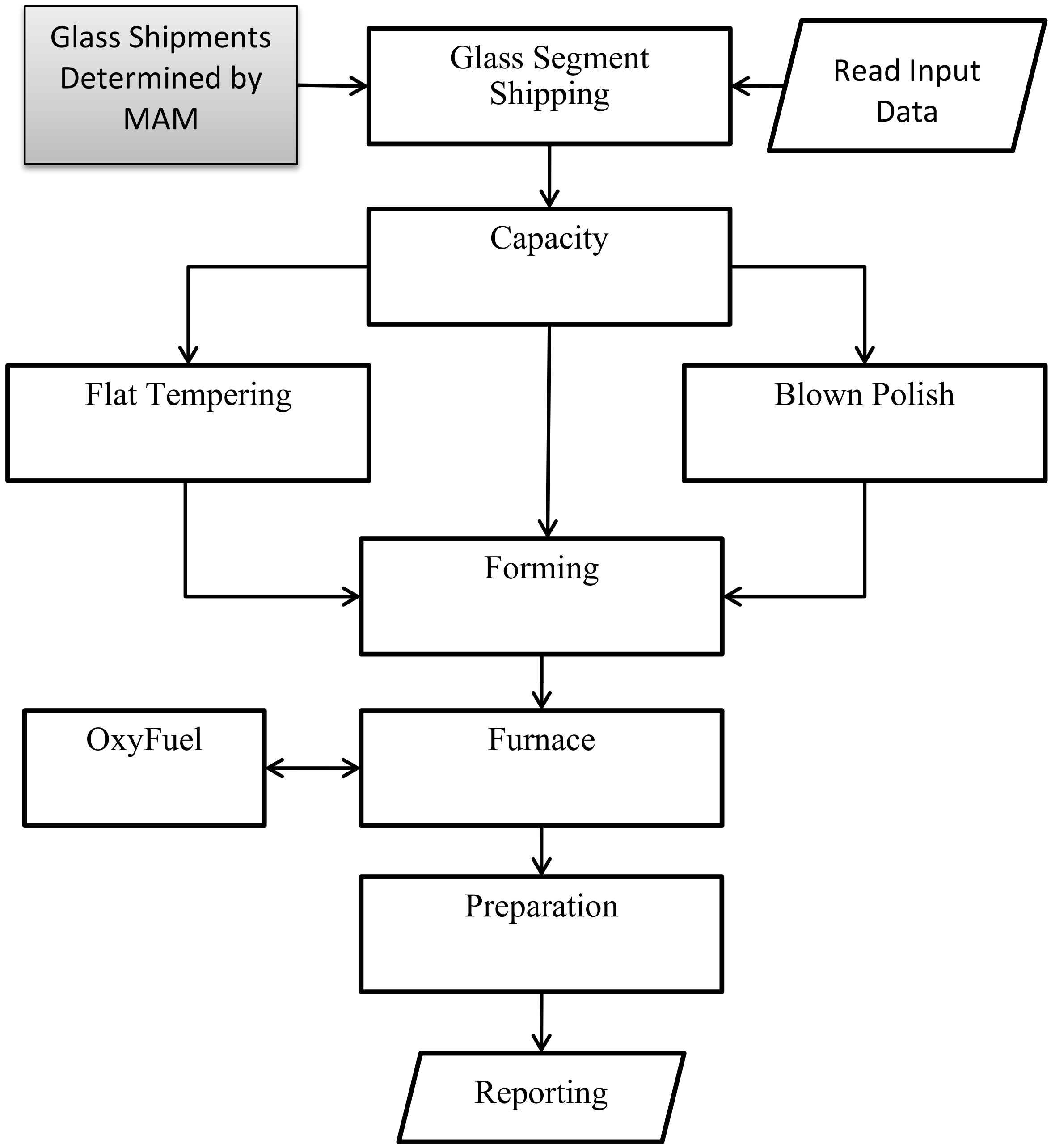
Table 23. Major U.S. glass industry segments and typical products modeled in the glass submodule, by NAICS code

Type of glass	North American Industry Classification System (NAICS) code	Description
flat glass	327211	Sheet plate and float glass for residential and commercial construction, automotive applications, tabletops, and mirrors.
container glass	327213	Packaging of foods, beverages, household chemicals, cosmetics, and pharmaceuticals.
blown glass	327212	Pressed and blown glass for tableware, cookware, lighting, televisions, liquid crystal displays, laboratory equipment, and optical communications.
fiberglass	327212	Textile and plastic reinforcement fibers for the construction, transportation, and marine industries.

Source: U.S. Census Bureau

Figure 14 summarizes the glass submodule execution. The code is run for each year in the projection period. The MAM determines the glass industry shipments in dollars. These shipments are then assigned to the four glass segments (subroutine GL_Shipping). The capacity requirement is estimated in metric tons for each glass segment. The capacity estimates include yearly estimates of both the remaining baseline capacity before the projection years and remaining new capacity added during the projection years, as well as the additional capacity required each year to meet demand. Flat glass and blown glass include finishing processes. All four glass segments have forming, furnace, and preparation processes. As new capacity is added for each process step in each glass segment, the technology is selected based on an evaluation of the relative economic benefit of the available technologies. An adjustment is made to fuel consumption for oxy-fuel furnaces (subroutine OxyFuel). The results are then reported.

Figure 14. Subroutine execution for the glass submodule in the Industrial Demand Module



Source: U.S. Energy Information Administration

The algorithms used for the four glass segments are the same with variations in parameters. The available technologies also vary by glass segment and are described in the next section followed by a description of the algorithms.

Technology choice options

Table 24 through Table 27[39] show the technologies that the submodule may select for the four glass segments and process steps. The base year technology share is shown. All listed technologies are options for the replacement of retired capacity, including those shown with a 0% share in the base year. The glass submodule only considers natural gas and electricity as fuels. The small amounts of other fuels used in glass production are based on the UEC/TPC data from MECS, which is outside of the glass submodule. All of the process steps shown in the figures below use electricity for various facilities support services. This electricity use is not part of the use of electricity as a fuel. In the case of the preparation process, the energy use is all electricity as part of services and not fuels. Even when the technology is the same among the four glass segments, the parameters associated with the technology, such as energy intensity, vary by glass segment.

Table 24. Flat glass technology choice in the glass submodule

Process steps and technologies	Base year technology share
Preparation	
Prep_1	99.9%
Prep_2	0.1%
Furnaces	
Furn_1	99.7%
Furn_2	0.0%
Furn_3	0.1%
Furn_4	0.0%
Furn_5	0.2%
Furn_HYB	0.0%
Form and finish	
Form_1	79.0%
Form_2	21.0%
Form_3	0.0%
Tempering	
FT_1	100.0%
FT_2	0.0%

Source: U.S. Energy Information Administration

Note: Preparation technologies only use electricity; all other technologies use both electricity and natural gas.

[39] SAIC, "Draft Report on Modeling the Mass and Energy Flow in the Glass Industry for the NEM-IDM, June, 2011.

Table 25. Container glass technology choice in the glass submodule

Process steps and technologies	Base year technology share	Energy source Natural gas	Energy source Electricity
Preparation			
CPrep_1	99.9%	no	yes
CPrep_2	0.1%	no	yes
Furnaces			
CFurn_1	20.0%	yes	yes
CFurn_2	29.7%	yes	yes
CFurn_3	50.1%	yes	yes
CFurn_4	0.0%	yes	yes
CFurn_5	0.0%	yes	yes
CFurn_6	0.0%	yes	yes
CFurn_7	0.0%	no	yes
CFurn_8	0.0%	yes	yes
CFurn_9	0.0%	yes	yes
CFurn_10	0.0%	no	yes
CFurn_HYB	0.0%	yes	yes
Form and finish			
CForm_1	49.3%	yes	yes
CForm_2	0.0%	yes	yes
CForm_3	50.7%	yes	yes

Source: U.S. Energy Information Administration

Table 26. Blown glass technology choice in the glass submodule

Process steps and technologies	Base year technology share	Energy source Natural gas	Energy source Electricity
Preparation			
BPrep_1	99.9%	no	yes
BPrep_2	0.1%	no	yes
Furnaces			
BFurn_1	69.4%	yes	yes
BFurn_2	5.4%	no	yes
BFurn_3	25.2%	yes	yes
BFurn_4	0.0%	no	yes
BFurn_5	0.0%	yes	yes
BFurn_HYB	0.0%	yes	yes
Form and finish			
BForm_1	99.8%	yes	yes
BForm_2	0.1%	yes	yes
BForm_3	0.1%	yes	yes

Process steps and technologies	Base year technology share	Energy source	
		Natural gas	Electricity
Polishing			
BPolish_1	100.0%	yes	yes
BPolish_2	0.0%	yes	yes

Source: U.S. Energy Information Administration

Table 27. Fiberglass technology choice in the glass submodule

Process step and technologies	Base year technology share	Energy source	
		Natural gas	Electricity
Preparation			
FPrep_1	99.9%	no	yes
FPrep_2	0.1%	no	yes
Furnaces			
FFurn_1	82.7%	yes	yes
FFurn_2	7.1%	yes	yes
FFurn_3	10.2%	no	yes
FFurn_4	0.0%	yes	yes
FFurn_HYB	0.0%	yes	yes
Form and finish			
FForm_1	100.0%	yes	yes
FForm_2	0.0%	yes	yes

Source: U.S. Energy Information Administration

Batch preparation

Batch preparation involves raw material selection and blending. The physical and chemical properties of the final glass product are determined by the raw material composition, which in turn varies with each type of glass produced. Of particular interest for most applications is the chemical durability, transmission, softening point, and thermal expansion of the glass. Raw materials consist largely of glass-forming oxides that may be grouped into network formers (SiO_2, B_2O_3, P_2O_5), intermediate oxides (Al_2O_3, TiO_2, ZrO_2), and network modifiers (Na_2O, CaO, MgO).

A typical soda-lime glass composition used for window or container glass consists of approximately 60% silica sand, approximately 18% calcium monoxide from limestone, and approximately 20% sodium monoxide from soda ash. Other common ingredients are feldspar, salt cake, colorants, and refining agents (for example, arsenic, sodium chloride). Added to the mixture of raw materials to be ground is cullet. Cullet is waste or broken glass, which may be generated at the plant or obtained from the marketplace. During batch preparation, the fine-ground raw materials are weighed according to the recipe and are subsequently mixed to achieve a homogenous composition. Cullet can be either mixed into the batch or added into the glass-melting furnace (or tank) simultaneously with the batch. Cullet from recycled glass is employed in container glass manufacturing. The IDM methodology to account for use of recycled cullet in container glass is described on page 38.

Melting furnaces

The melting of glass, with the exception of a few blown glass manufacturing processes, is accomplished with continuously operating tank furnaces. Discontinuous glass melting processes operate as pot furnaces and day tanks. In pot furnaces, one or more refractory crucibles are filled with batch and cullet and are placed in a natural gas-fired or electrically heated furnace. After melting the batch, the temperature of the furnace is typically increased to lower the melt viscosity and activate refining agents to remove bubbles from the melt (refining). The temperature is then lowered to condition the glass for forming. Day-tanks are small tanks that are charged with batch and cullet. As in a pot furnace, the temperatures are adjusted for melting, refining, and conditioning of the glass melt.

A typical glass-melting tank consists of a batch charging area (the doghouse) attached to a refractory basin covered by a refractory superstructure (the crown). Presently, most glass furnaces in the United States are heated with natural gas. Common heating methods are air-fuel burners and, more recently, oxy-fuel burners. Some furnaces use direct electrical heating (Joule heating), in particular, for wool-type fiberglass production that provides more uniform temperature distributions compared with natural gas heaters. Combinations of both heating methods (electric boosting) are used to help melt the glass because glass is an electrical conductor at high temperatures. Electric boosting typically consists of 10%−30% of the total energy demand, but it increases production rates and the flexibility of the furnace operation.

Common to both flat and container industry segments are regenerative and recuperative furnaces. Fiberglass furnaces are generally smaller than container and flat glass furnaces. Pressed and blown glass (specialty glass) furnaces are the smallest. To improve energy efficiency and achieve higher flame temperatures, air-fuel furnaces typically recover heat from exhaust gas streams with regenerative systems to preheat the combustion air. In regenerative systems, the exhaust gases stream through large chambers packed with refractory bricks arranged in patterns forming open conduits.[40] A fluidized bed reactor is a type of reactor device that can be used to carry out a variety of multiphase chemical reactions where a fluid (gas or liquid) is passed through a granular solid material at high enough velocities to suspend the solid and cause it to behave as though it were a fluid. The advanced glass melter is a projected technology based on the most energy-efficient current technologies.

Forming and conditioning

After completion of the refining stage, the homogenous, bubble-free glass leaves the tank and enters the forehearth, sometimes through a specifically designed pathway (channel or throat). The main function of the forehearth is to condition the glass, that is, to deliver glass with the desired temperature and temperature distribution to the forming process. Any deviations from the desired thermal profile can cause undesirable differences in viscosity and subsequently lead to visible defects in the finished product. Forehearths can be natural gas-fired or electrically heated.

The conditioned glass is delivered from the forehearth to the forming equipment at a constant rate. Depending on the process, the viscous glass stream is either continuously shaped (float glass, fiberglass),

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[40] Worrell, Ernst, Christina Galitsky, et al., March 2008, *Energy Efficiency Improvement and Cost Savings Opportunities for the Glass Industry*, An Energy Star Guide for Energy and Plant Managers, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-57335.

or severed into portions of constant weight and shape, which are delivered to a forming machine (container glass). Advanced process control is also an energy efficiency technology considered. For some glass segments, an advanced projected technology is based on the most energy-efficient current technologies.

Glass submodule algorithms

Each of the following sections describes the algorithms associated with the flat glass segment, which are the same as the algorithms for the other three glass segments. Parameters vary to account for differences in energy intensity, retirement rates, costs, etc. Different variable and parameter names associated with the four glass segments are distinguished with abbreviations for the glass segments.

GL_Shipping Subroutine (glass segment shipping)

The GL_Shipping subroutine applies to all of the glass segments. The shipment data from MAM is for the entire glass industry. The historical shipments for the four glass segments are based on historical shipment shares applied to historical shipment data for the glass industry. The projected shipment shares for three of the four glass segments are based on linking glass shipments by category to other industries that are correlated with glass shipments by glass segment, while flat glass has its own shipment series:

$$GL\_fg\_ship_y = mc\_revind_{mnumcr,29,y} \tag{167}$$

$$ybg_y = 0.048151 * 0.24 * \ mc\_revind_{mnumcr,7,y} \ + 2.932934 \tag{168}$$

$$ycg_y = 0.003772 * mc\_revind_{mnumcr,1,y} + 2.533845 \tag{169}$$

$$ygp_y = 0.070395 * \ mc\_revind_{mnumcr,23,y} \ - 2.77323 \tag{170}$$

where

$GL\_fg\_ship_y$ = flat glass shipments for year *y*;

ybg_y = blown glass shipments for year *y*;

ycg_y = container glass shipments for year *y*;

ygp_y = glass products such as fiberglass and textile shipments for year y;

$mnumcr$ = aggregated census division for shipments; and

mc_revind = MAM variable that denotes gross output for flat glass (29), textiles (7), food (1), and plastics (23).

The shipments for the three estimated glass segments are then summed to provide a subtotal, which is only used to estimate shares for these three glass segments. The shipment shares based on the estimated shipments are then applied to the total glass shipments from MAM minus flat glass shipments to determine the shipments for the glass segments, as follows:

$$ysubtot_y = ybg_y + ycg_y + ygp_y \tag{171}$$

$$GL\_bg\_ship_y = \frac{ybg}{ysubtot} * \left(mc\_revind_{mnumcr,24,y} - GL\_fg\_ship_y\right) \tag{172}$$

$$GL\_cg\_ship_y = \frac{ycg}{ysubtot} * \left(mc\_revind_{mnumcr,24,y} - GL\_fg\_ship_y\right) \tag{173}$$

$$GL\_gp\_ship_y = \frac{ygp}{ysubtot} * \left(mc\_revind_{mnumcr,24,y} - GL\_fg\_ship_y\right) \tag{174}$$

where

$ysubtot_y$	= total shipments less flat glass shipments, estimated based on correlated industries for year *y*;
$GL\_fg\_ship_y$	= flat glass shipments for year *y*;
$GL\_bg\_ship_y$	= blown glass shipments for year *y*;
$GL\_cg\_ship_y$	= container glass shipments for year *y*;
$GL\_gp\_ship_y$	= glass product shipments such as fiberglass and textiles for year *y*; and
$mc\_revind_{mnumcr,24,y}$	= shipments for all census divisions (11), the overall glass industry (24), and for year *y*.

GL_Flatcap, GL_Contcap, GL_Blowncap, and GL_Fibercap Subroutines (capacity subroutines for the four glass segments)

When existing capacity is retired, it is then replaced with new capacity. The capacity subroutines estimate the needed capacity each year based on the retirement of both the starting baseline capacity and the retirement of new capacity that is added over the projection years. The equations are from the GL_Flatcap subroutine associated with the flat glass sector, but they apply to all forms of glass.

The initial starting baseline capacity for the glass segments is an input based on historical data, which is then converted from short tons to metric tons. The survival function determines the share of needed capacity added in a previous year that survives to the current model year. An example is shown in Figure 11. In addition to baseline capacity retirements and surviving capacity, needed capacity additions are calculated in subroutine Step_Capacity (page 95).

Technology shares and energy use for the process steps

After the needed capacity is calculated for the current year, the technology shares are assigned to the needed capacity. Each of the process steps for each of the glass segments has the associated technologies assigned to the needed capacity. The algorithm is the same for all of the process steps for all four glass segments. The technology shares for each new technology are calculated in subroutine Logit_Calc (page 97).

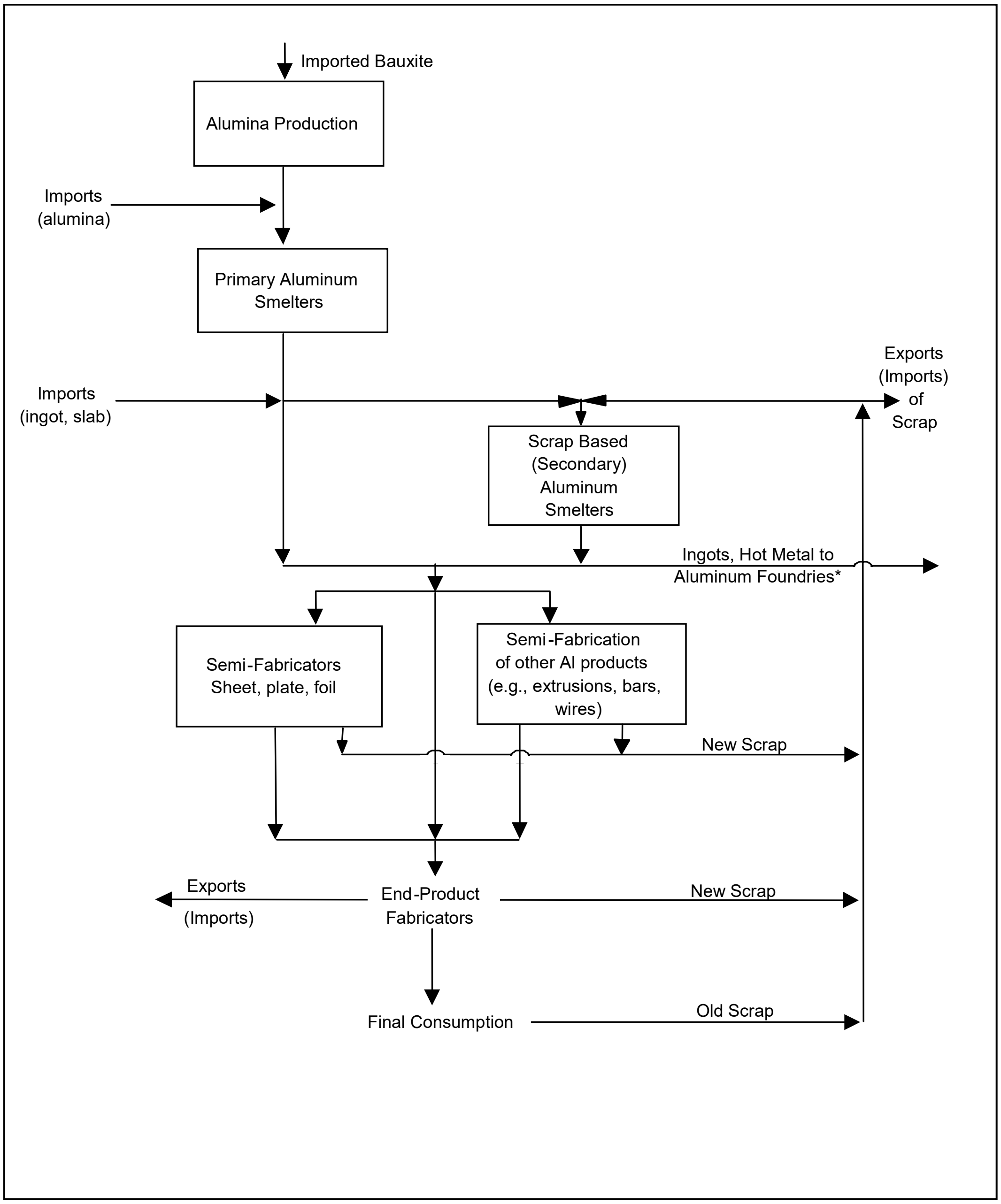
GL_OXY_Fuel Subroutine

Modern glass furnace technology aims to increase the use of oxygen as a way to increase fuel efficiency and reduce emissions of nitrogen oxides (NOx). Consequently, oxygen is increasingly being used to replace air in combustion. The shares for the use of oxygen are set at 0.2.

ALUMINUM INDUSTRY

Figure 15 shows a detailed process flow diagram for aluminum manufacturing. Accurate modeling of this heterogeneous and complex industry requires an optimal submodule from the range of submodules that simulate this sector. Some submodules require very specific processing details compared with those submodules that use macroscopic industry representations. In the IDM's modeling approach, the process is first broken down into several unit operations using process engineering techniques. The energy consumed by each unit operation and the corresponding mass flow of material (raw materials, intermediates, or final products) through that unit operation are calculated from the data. Their ratio supplies the UEC specific for that unit operation. The energy demands for processing the required mass of material through each unit operation are calculated and aggregated to provide the total energy consumption for the desired amount of the products. Because the aggregated estimate can calculate energy demands at the unit operation level, it is a more accurate calculation of energy consumption compared with that from a global UEC. This approach is discussed in detail in the later sections, starting with a description of the aluminum manufacturing process.

Figure 15. Aluminum industry process flow in the aluminum submodule



Source: U.S. Energy Information Administration

The U.S. aluminum industry consists of two major sectors: the primary aluminum sector, which uses alumina as raw material; and the secondary sector, which uses collected aluminum scrap as a raw material. The primary and secondary aluminum industries have historically catered to different markets, but these distinctions are fading. Traditionally, the primary industry bought little scrap and supplied wrought products, including sheet, plate, and foil. The secondary industry is scrap-based and has historically supplied foundries that produce die, permanent mold, and sand castings. More recently, secondary aluminum smelters have started supplying wrought (sheet) stock. In addition, in the past decade, the primary producers have been moving aggressively into recycling aluminum, especially used beverage cans.

Figure 15 provides an overview of the process steps involved in the aluminum industry. The energy use analysis accounts for energy used in NAICS 3313, which includes the following:

- alumina refining (NAICS 331311; aluminum foundry castings are not considered as part of NAICS 331311)
- primary aluminum production (NAICS 331312)
- secondary smelting and alloying of aluminum (NAICS 331314)
- aluminum sheet, plate, foil manufacturing (NAICS 331315)
- aluminum semi-fabrication of products such as extrusions, tube, cable, and wire (found in NAICS 3316 and NAICS 331319)

Background on aluminum industry

The U.S. aluminum industry is a broadly diversified industry, starting with ore refining and ending with a wide variety of industrial and consumer products[41]. Aluminum is the third most abundant element in the earth's crust, but it does not occur in nature as a metal, only as an oxide (alumina), which in turn is found in an ore called bauxite. In recent years, aluminum has begun to replace iron and steel in the automotive, electric power, and construction industries because of its lighter weight, resistance to rust, alloy ability, and recyclability. It is popular as a packaging material for beverages and food containers, as well as household and institutional foil.

The supply of aluminum in the United States stems from three basic sources:

- primary production—domestic production from aluminum ore
- secondary production—domestic metal recovered from scrap, in other words, recycling
- imports—primary and secondary ingots and mill products

The end product from the first two sources is molten aluminum metal, which is not in a form suitable for marketing to potential end users. Instead, ingot casting is the vital conduit between the molten metal and the manufacture of aluminum and aluminum alloy products. Extrusions, forgings, sheet, plate, and foil begin as billet and fabricating ingots. Sand, permanent mold, investment, and pressure die castings typically originate in alloyed re-melt ingots. For this modeling effort, aluminum imports are assumed to also be processed like primary and secondary aluminum into end-use products.

Currently there are more than 400 wrought aluminum and wrought aluminum alloys and more than 200 aluminum alloys in the form of castings and ingots to match the wide range of material characteristics required by end-use manufacturing processes[42]. In some cases, ingot formation and the manufacture of the final aluminum product for end-use applications are in the same location.

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[41] All bauxite for primary production is assumed to be imported to the United States.
[42] For aluminum specifications, see the Aluminum Association, http://www.aluminum.org/Content/NavigationMenu/TheIndustry/IndustryStandards/Teal_Sheets.pdf.

ALUMINUM_INDUSTRY submodule

For this modeling effort, the boundaries established for the macroscopic modeling of the aluminum industry begin with the delivery of bauxite or scrap aluminum at the plant gate and end with ingot formation and the manufacture of aluminum sheet, plate, foil, and extruded products. Aluminum foundry operations for die and non-die casting are included.

The total energy consumed by the aluminum industry will be the sum of the energy consumed by the three modeled segments: primary aluminum production, secondary aluminum production, and product formation. Internal submodule calculations are in metric units, which are converted to English units for calculations external to this submodule.

Aluminum production

Aluminum production is defined as aluminum supply minus aluminum imports plus aluminum exports plus changes in stocks. These values are obtained exogenously from other NEMS modules or from the U.S. Geological Survey (USGS).

The output of the ALUMINUM_INDUSTRY submodule is the total quantity of aluminum shipments or gross output (in thousand metric tons) in a given year. A physical production index is derived as follows:

$$index2006 = \left[\frac{OUTIND_{13,11}}{ALUMIBYR}\right] \qquad (175)$$

where

$index2006$ = index of gross output of aluminum shipments, projected for the aluminum industry;

$OUTIND_{13,11}$ = gross value of output for the aluminum industry (IDM industry code of 13) for the nation in the current projection year, as determined by the MAM; and

$ALUMIBYR$ = gross value of output for the aluminum industry for the nation in the base year, as determined by the MAM.

Primary and secondary production shares

In the past few years, the share of secondary U.S. aluminum production increased above its historical share to nearly 80% of total aluminum output. This large share appears to be a permanent condition[43]. As a result, secondary aluminum production throughout the projection period is constrained to be no less than 75% of total U.S. production.

The IDM allows separates physical aluminum production into the primary and secondary production industries as follows:

$$sumprodcur_{1,y} = is\_production_{1,y} * index2006 * primprod\_percent_{y} \qquad (176)$$

[43] Skelton, Matthew, "U.S. Primary Aluminum Production Remains Low despite Slow Increase in Prices," *Today in Energy*, (Washington, DC: September 12, 2017) https://www.eia.gov/todayinenergy/detail.php?id=32872

$$sumprodcur_{5,y} = is\_production_{1,y} * index2006 * \left(1 - primprod_{percent_{y}}\right) \quad (177)$$

where

$sumprodcur_{1,y}$ = physical output from step 1 of the aluminum process (primary smelting), which represents primary production from the aluminum industry (IDM industry code of 13) for the nation in the current projection year *y*, as determined by the MAM and USGS statistics;

$sumprodcur_{5,y}$ = physical output from step 5 of the aluminum process (secondary production),

$is\_production_{1,y}$ = physical output from the aluminum industry (IDM industry code of 13) for the nation in the current projection year, as determined by the MAM and USGS statistics; and

$primprod\_percent_{y}$ = percentage of primary production of aluminum industry (IDM industry code of 13) for the nation in the current projection year *y*, as determined by regressions of endogenous NEMS variables related to fuel prices and USGS production statistics.

Idled primary capacity can be brought back into production. Total production capacity will then be increased to meet the macroeconomic outputs as described for other process flow industries. For each year following the base year, incremental additions to aluminum capacity are based on the following assumptions:

- baseline capacity is retired at a linear rate over a fixed time frame;
- production demand in excess of surviving baseline capacity will first be met with idled equipment; and
- equipment acquired after the base year will retire according to a logistic function.

Aluminum baseline capacity that survives is computed as shown on page 96.

AL_ANODE_PRD

Primary aluminum smelting consumes petcoke-based anodes. Each primary aluminum smelting technology has a parameter in the ironstlx.xlsx input file defining the metric tons of anode consumed per metric ton of aluminum produced, with the exception inert anode (technology IA_1), which demands no additional anode volumes. The AL_ANODE_PRD subroutine determines the amount of anode anode needed by the primary smelting process step, then determines the technology shares of anode production capacity and the energy consumed to make the metric tons of anodes demanded by primary aluminum smelting.

Unlike other process steps, anode production does not use a logit function to determine technology shares. Instead, existing anode production capacity uses the PBA_NG1 (less efficient prebake) technology, while any new anode production capacity uses the PBA_NG2 (more efficient prebake) technology. The Söderberg anode production technology is no longer represented in the IDM as of AEO2025.

Remaining ALUMINUM_INDUSTRY submodule subroutines

Technology selection and energy demand calculations for the remaining process steps are carried out in the TECH_STEP subroutine (see page 97). Additionally, the AL_PROD_FORM subroutine uses calculated shipments and parameters from the ironstlx.xlsx input file to determine the fuel used in aluminum product formation.

Influence of purchased electricity price on aluminum production

In addition to the process flow submodule described above, the IDM also incorporates a regression-based modifier to allow the purchased electricity price to help drive the choice between primary or secondary production. Primary production involves electrochemical smelting of alumina and is very electricity-intensive as compared with the more natural-gas-intensive secondary (recycled) aluminum production, and so the industrial purchased electricity price can play a role in the production pathways choice. A regression was performed with the historical primary-secondary ratio and industrial purchased electricity prices (both current and lagged), as follows:

$$ALRATIO_r = PCRX_{f=1,r} * ALSLOPE_r + PCRXLAG_{f=1,r} * ALSLOPELAG_r + ALINTERCEPT_r \qquad (178)$$

where

$PCRX_{f,r}$ = the industrial purchased electricity price (*f=1*), by region *r;*

$PCRXLAG_{f,r}$ = the lagged (current year – 1) industrial purchased electricity price (*f=1*)*;*

$ALSLOPE_r$ = slope regression parameter, by region *r;* and

$ALSLOPELAG_r$ = intercept regression parameter, by region *r.*

The regression parameters were developed based on historical USGS data from 1996 to 2010 (based on unpublished data from the U.S. Bureau of Mines and the U.S. Geological Survey—Minerals Yearbook and its predecessor, Mineral Resources of the United States) (Table 28).

Table 28. Regression parameters for primary and secondary aluminum production projections in the aluminum submodule

Parameter	Region 1	Region 2	Region 3	Region 4
Alslope	-0.000199	-0.000856	0.000324	-0.00227
Alslopelag	-0.000193	0.001498	-0.00142	-0.000394
alintercept	0.5645	0.10153	0.99405	2.1385

Source: U.S. Energy Information Administration

The multiple variable regressions provided for the four regions resulted in squared multiple correlations R^2 of 0.63, 0.49, 0.83, and 0.89 for regions 1 through 4, respectively. Although the coefficients for regions 1 and 2 are weak (not close to 1.0), the region with by far the most aluminum output, region 3, had a strong R^2 (close to 1.0). Moreover, all regions except region 1 (which accounts for only 15% of total U.S. aluminum output) had at least one slope variable (Alslope or Alsloplag) with a statistical significance of 90% ($p < 0.1$). Although we did not perform a formal Dickey-Fuller test, inspection of plots of the first-differences of the dependent variables indicated sufficient stationary behavior.

The adjusted primary and secondary production throughputs are then re-adjusted as follows:

$$PRODFLOW_{primary,r} = ALRATIO_r * ALPRODFLOWTOTAL_r \quad (179)$$

$$PRODFLOW_{secondary,r} = ALPRODFLOWTOTAL_r - PRODFLOW_{primary,r} \quad (180)$$

where $PRODFLOW_{primary,r}$ and $PRODFLOW_{secondary,r}$are production rates for primary and secondary aluminum in region r, respectively, and $ALPRODFLOWTOTAL_r$ is the sum of primary and secondary aluminum production before electricity-related price adjustments.

Additional technical choice subroutines common to the iron and steel and paper industries

In addition to using Tech_Step and its associated subroutines (page 95), the iron and steel industry and the pulp and paper industry submodules share two common technical choice subroutines:

- XX_PRODCURBreakout: computes the PRODCUR matrix of total production needed to meet demand for each process step. This demand will differ by industry. IS_PRODCUR_Breakout computes the PRODCUR matrix for the iron and steel industry, and PP_PRODCURBreakout computes the PRODCUR matrix for the pulp and paper industry.
- XXSteam: computes steam demand and CHP use. Subroutine IS_Steam computes steam demand for the iron and steel industry and subroutine PPSteam computes steam demand for the pulp and paper industry.

Subroutine IS_PRODCUR_Breakout

The iron and steel submodule separately addresses material flows through each of a series of component steps. These steps represent the intermediate (and occasionally competing) processes that are required to produce the volume of steel output projected by the MAM. This calculation is represented by an input-output model of the form that follows:

$$(I - PRODFLOW) * PRODCUR = d \quad (181)$$

Solving for $PRODCUR$ yields the following:

$$PRODCUR = (I - PRODFLOW)^{-1} * d \quad (182)$$

where

$PRODFLOW$	= input or output coefficient matrix with final demand as the first column and the production steps as the other columns. The coefficients are the values in the *PRODFLOW* array;
I	= identity matrix;
d	= final demand vector, where the first element (d_1) is equivalent to PRODX (calculation details starting on page 125, and the remaining elements are zero); and
$PRODCUR$	= matrix of productive capacity needed to meet the final demand.

In the legacy approach, there are two $PRODFLOW$ matrices, corresponding to old and new technologies. These matrices remain static and are used, with capacity retirement rates for each producing step, to model the evolution of the industry.

The current approach models this evolution by dynamically changing the elements of a single $PRODFLOW$ matrix, capturing industrial evolution through incremental adjustments of the $PRODFLOW$ elements. The $PRODFLOW$ matrix is an array of elements that indicate the output of predecessor steps required to produce one unit (that is, metric ton) of output from the current step.

The PRODCUR calculation produces estimates of material flow for seven process steps and four census regions. The pulp and paper submodule requires the flows to be aggregated into national totals and then broken out into sub-steps that will be used as inputs to the technology choice submodules, below. In its simplest form, the aggregated total is expressed as follows:

$$SumProdCur_{j,y} = \sum_{r=1}^{4} prodcur_{j,r,y} \tag{183}$$

where

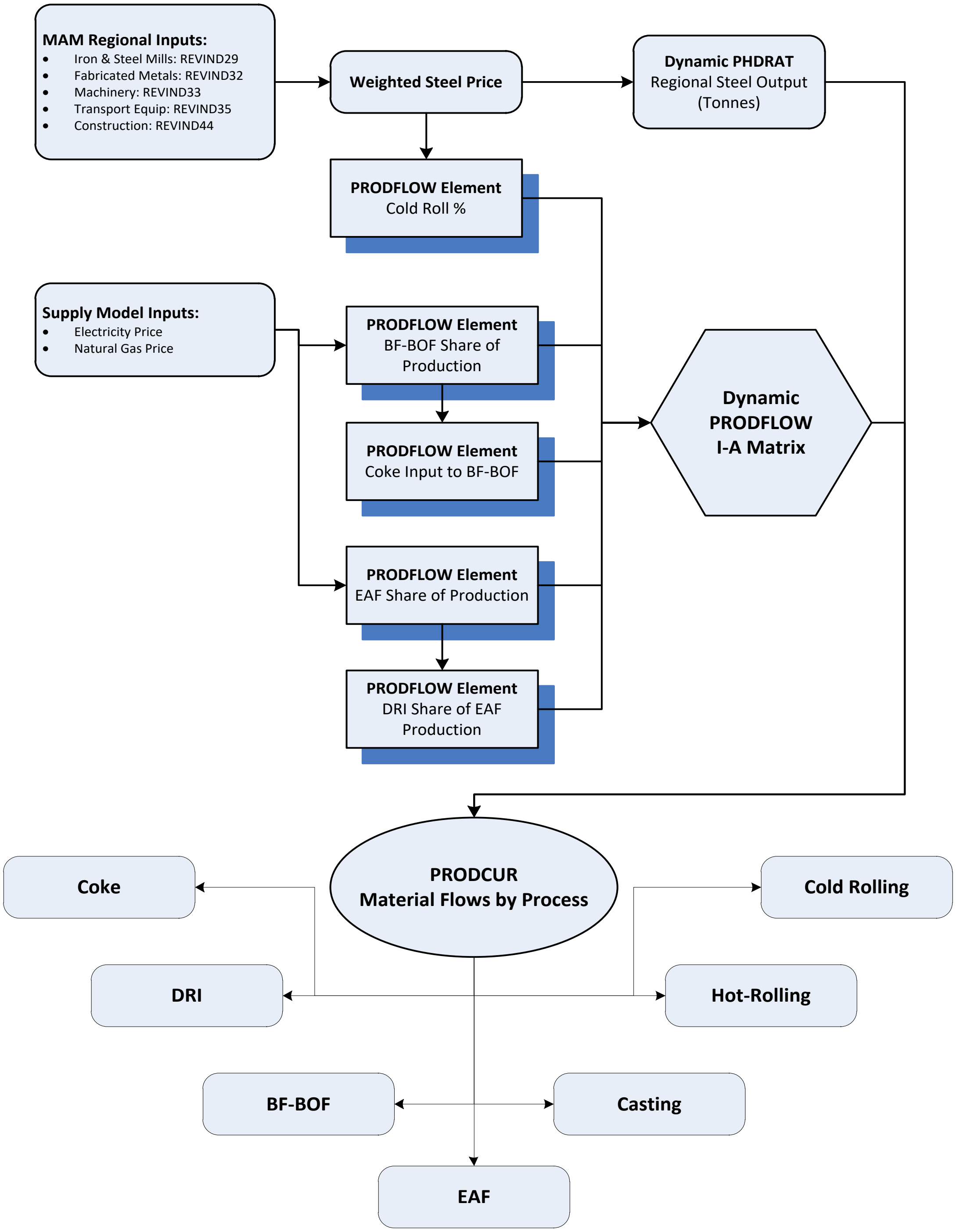
$SumProdCur_{j,y}$	= total U.S. production required to meet demand for process step *j* and year *y*, calculated above as a breakout of the $PRODCUR$ components, summed across regions r; and
$prodcur_{j,r,y}$	= regional element of PRODCUR matrix for step j in year y. Details of its calculation are on page 123.

IRON AND STEEL INDUSTRY

Iron and steel submodule flow

The iron and steel submodule, like other energy-intensive industry submodules, is based on estimated flows of material across several process steps to ultimately meet final demand projections generated by the MAM.

Figure 16. Detailed iron and steel submodule flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

The MAM provides estimates of the value of steel produced, and the iron and steel submodule converts these estimates into metric tons of material flows through the various process steps. The submodule uses a conversion factor (PHDRAT) to translate dollars of output to metric tons of production (PRODX).

Table 29. Iron and steel processes and technologies in the iron and steel submodule

Iron and steel step/PRODCUR element	PRODCUR step index (IS)	Technology choice?
hot rolling	1	yes
cold rolling	2	no
continuous casting	3	yes
blast furnace/basic oxygen furnace	4	yes
electric arc furnace	5	yes
direct reduced iron	6	yes
coke production	7	no

Source: U.S. Energy Information Administration

Table 30. (I-PRODFLOW) matrix example for region 1

(Steps/IS)		PRODX	Hot rolling	Cold rolling	Continuous casting	BF/BOF	EAF	DRI	Coke
		1	0	0	0	0	0	0	0
hot roll	1	-1.047	1	0	0	0	0	0	0
cold roll	2	**-0.451**	0	1	0	0	0	0	0
continuous casting	3	0	-0.954	0	1	0	0	0	0
blast furnace/basic oxygen furnace (BF/BOF)	4	0	0	0	**-0.310**	1	0	0	0
electric arc furnace (EAF)	5	0	0	0	**-0.754**	0	1	0	0
direct reduced iron (DRI)	6	0	0	0	0	**0.000**	**0.000**	1	0
coke	7	0	0	0	0	**-0.983**	0	0	1

Source: U.S. Energy Information Administration

This example suggests that for every metric ton of steel produced in this region, 1.047 metric tons of material has passed through the hot rolling step and 0.451 metric tons through the cold rolling step. In the legacy module, all these coefficients are held constant; in the current module, the bolded coefficients in Table 30 are subject to change, based on economic conditions and assumptions about trends in the direction of manufacturing technologies.

To reiterate, the variable PRODCUR represents the flows of material (on a regional basis), in thousand metric tons, through each of the seven process steps (Table 29). The current module uses these process flows as inputs to subprocesses, in which the choice of technology will determine the consequent demand for energy. This process is done on a national, rather than a regional level. Accordingly, the PRODCUR element for specific steps is summed across regions and then is broken out into sub-flows for this submodule.

Table 31. General (I-PRODFLOW) matrix for iron and steel subroutine

	PRODX	Hot rolling	Cold rolling	Continuous casting	BF/BOF	EAF	DRI	Coke
PRODX	1	0	0	0	0	0	0	0
hot rolling	-a	1	0	0	0	0	0	0
cold rolling	-b	0	1	0	0	0	0	0
continuous casting	0	-c	0	1	0	0	0	0
bast furnace/basic oxygen furnace (BF/BOF)	0	0	0	-d	1	0	0	0
electric arc furnace (EAF)	0	0	0	-e	0	1	0	0
direct reduced iron (DRI)	0	0	0	0	-h	-m	1	0
coke	0	0	0	0	-k	0	0	1

Source: U.S. Energy Information Administration

Inverting the above matrix and multiplying terms provides the necessary output for each step of the production process as following:

$$prodcur_{r,y} = PRODX_{r,y} \tag{184}$$

$$qHotRoll_{r,y} = a * PRODX_{r,y} \tag{185}$$

$$qColdRoll_{r,y} = b * PRODX_{r,y} \tag{186}$$

$$qContCasting_{r,y} = (ac) * PRODX_{r,y} \tag{187}$$

$$qBF\_BOF_{r,y} = (acd) * PRODX_{r,y} \tag{188}$$

$$qEAF_{r,y} = (ace) * PRODX_{r,y} \tag{189}$$

$$qDRI_{r,y} = [ac(dh + hm)] * PRODX_{r,y} \tag{190}$$

$$qCoke_{r,y} = (acdk) * PRODX_{r,y} \tag{191}$$

where

$prodcur_{r,y}$ = total steel material flow;

$qHotRoll_{r,y}$ = $prodcur_{is=1,r,y}$ quantity of hot rolling material flow needed to meet steel demand;

$qColdRoll_{r,y}$ = $prodcur_{is=2,r,y}$ quantity of cold rolling material flow needed to meet steel demand;

$qContCasting_{r,y}$ = $prodcur_{is=3,r,y}$ quantity of continuous casting material flow needed to meet steel demand;

$qBF/BOF_{r,y}$ = $prodcur_{is=4,r,y}$ quantity of blast furnace/basic oxygen furnace (BF/BOF) material flow needed to meet steel demand;

$qEAF_{r,y}$ = $prodcur_{is=5,,r,y}$ quantity of electric arc furnace material flow (EAF) needed to meet steel demand;

$qDRI_{r,y}$ = $prodcur_{is=6,r,y}$ quantity of direct reduced iron (DRI) material flow needed to meet steel demand;

$qCoke_{r,y}$ = $prodcur_{is=7,r,y}$ quantity of coking material flow needed to meet steel demand;

$PRODX_{r,y}$ = final physical steel demand for region r and year; and

a, b, c, d, e, h, k, m = elements of $(I - A)^{-1}$.

The PHDRAT and the PRODFLOW matrices are used to obtain regional process flows through each step (PRODCUR). The regional flows are summed to a national total, and each process step (EAF, DRI, cold roll, etc.) is represented by a national-level technology choice submodule. Total resulting fuel demand for each process step is then allocated back to the four regions based on their respective shares of national material flow.

For example, national hot rolling material flow needed to meet annual demand is obtained from summing up the regional material flows across the four census regions, as follows:

$$SumProdCur_{is=1,y} = \sum_{r=1}^{4} prodcur_{r,y} \tag{192}$$

where

$SumProdCur_{is=1,y}$ = national hot rolling output.

For each of the process steps described below, there are two sets of calculations. First, the existing capacity to meet demand is calculated, and, if this capacity is insufficient, incremental needed capacity is calculated and added. Second, added productive capacity is allocated among competing technology choices, based on a logistic model that is a function of the competing technologies' attributes.

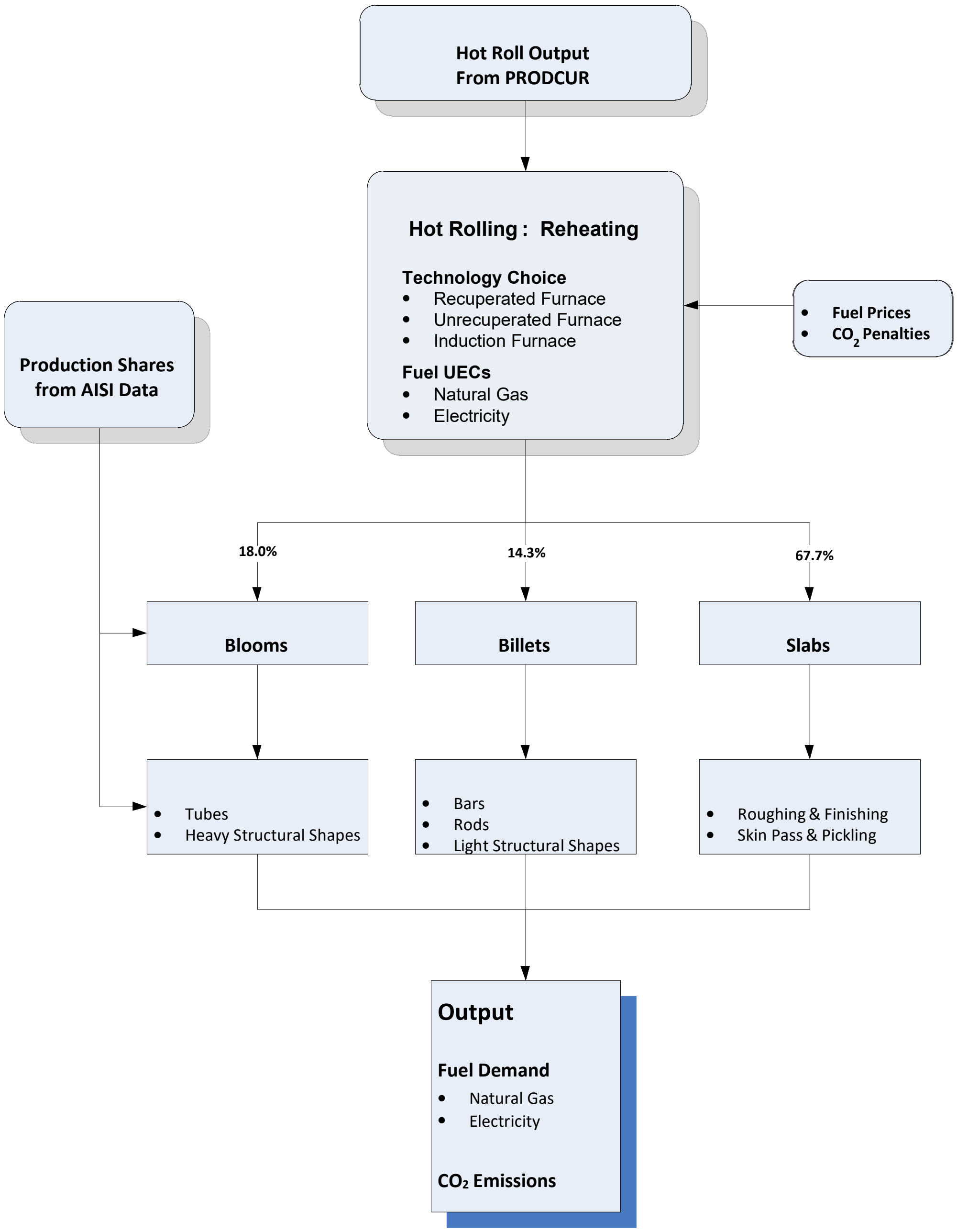
Capacity allocation in iron and steel manufacturing processes

The following sections describe the individual manufacturing processes addressed by the iron and steel submodule. Each set of technology attributes is derived from various sources. Seven process steps are described in the order presented in PRODCUR, beginning with the final output of steel components and ending with the requirement for coke production.

Hot Rolling: IS = 1

The hot rolling step takes raw steel forms from the casting process (blooms, billets, and slabs), reheats them, and produces various structural products such as tubes, bars, and rods. The figure below depicts the flows of material through the hot rolling step.

Figure 17. Hot rolling process step in the iron and steel submodule



Source: U.S. Energy Information Administration

The process flow of steel is associated with three intermediate forms obtained from the casting subprocess: blooms, billets, and slabs. These forms are allocated according to 2018 estimates obtained internally from American Iron and Steel Institute (AISI).

Table 32. Steel reheating baseline technology shares and attributes in the iron and steel submodule

Technology	Technology share (base year)	Capital costs (dollars per thousand metric tons of capacity)	Operation and maintenance costs (dollars per year per thousand metric tons of capacity)	Natural gas (million British thermal units per thousand metric tons)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)
recuperated reheating furnace	0.0%	28,695	10	3,317	0	174
unrecuperated reheating furnace	40.0%	16,447	952	5,136	0	270
direct rolling reheating furnace	60.0%	82,235	952	1,019	247	53

Source: U.S. Energy Information Administration

The first stage of this step is to determine the material flow for all subprocesses. The variable $SumProdCur_{IS=1,y}$ is calculated by summing regional material flows. An example is found on page 128. Once national output is known, subroutine Step_Capacity (page 95) determines how much, if any, capacity needs to be added. Technologies will be chosen for added capacity (see subroutine Logit_Calc on page 97).

For the hot rolling step, only the reheating subprocess uses endogenous technology choice. Technology shares for blooms, billets, and slabs are user-determined.

For the reheating subprocess, the fuel demand by technology, fuel, and year is given as follows:

$$Energy\_Use_{IS=1,Tech,f,y} = Tot\_Prod\_Tech_{IS=1,Tech,y} * Fuel\_Use_{IS=1,Tech,f,y} \quad (193)$$

where

$Energy\_Use_{IS=1,Tech,f,y}$ = total energy use, in MMBtu, for each technology;

$Fuel\_Use_{IS=1,Tech,f,y}$ = energy intensity of reheating furnaces, in MMBtu/thousand metric tons, by fuel *f* and technology *Tech*; and

$Tot\_Prod\_Tech_{IS=1,Tech,y}$ = total material flow, in thousand metric tons for each technology.

After reheating, the steel is cast into forms. The material flow for each form is calculated as follows:

$$Form\_Flow_{IS=1,i,y} = SumProdCur_{IS=1,y} * FormShares_{IS=1,i} \quad (194)$$

where

$Form\_Flow_{IS=1,i,y}$ = metric tons of production for form i (where 1=blooms, 2=billets, and 3=slabs); and

$FormShares_{IS=1,i}$ = allocation shares, from 2012 estimates of the American Iron and Steel Institute, currently held static.

Table 33. Production shares for casting forms in the base year of the iron and steel submodule

Blooms	Billets	Slabs
18.0%	14.3%	67.7%

Source: U.S. Energy Information Administration based on the American Iron and Steel Institute's *2018 Annual Statistical Report*

The forms are used to produce different structural products. For blooms, the primary products are tubes and heavy structural shapes. For billets, the products are bars, rods, and light structural shapes. The initial allocation of billets and slabs to products is based on AISI data for 2018. We set a final share for 2040 based on analyst judgment. Shares change linearly between the initial and final shares, and remain constant at the final share from 2040 on.

The energy requirement for blooms or billets is given as follows:

$$Energy\_Use_{IS=1,i,f,y} = \sum_{Prod} Form\_Flow_{IS=1,i,y} * Prod\_Share_{IS=1,i,y} * Fuel\_Use_{IS=1,i,f,y} \tag{195}$$

where

$Prod\_Share_{IS=1,i,y}$ = allocation share of products associated with form i (for $Prod$ 1=blooms, 2=billets, and 3=slabs) in year y for process step 1; and

$Fuel\_Use_{IS=1,i,f,y}$ = fuel f unit energy consumption for the associated product i in year y for process step 1, in MMBtu per thousand metric tons. For slabs, the only fuel used is electricity.

Table 34. Technology shares and attributes for hot roll process

		Initial process share (base year)	Final process share (2040)	Natural gas (million British thermal units per thousand metric tons)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)
blooms						
	tubes	14%	13%	6,597	1,314	0.3462
	heavy structural shapes	86%	87%	2,745	593	0.1440
billets						
	bars	43%	46%	2,081	844	0.1092
	rods	21%	20%	2,199	1,125	0.1154
	light structural shapes	36%	34%	2,081	677	0.1092

Source: U.S. Energy Information Administration

For slabs, the approach is slightly different. All slabs go through three subsequent processes: roughing, finishing, and either the skin-pass or pickling process. Each process has more than one technology. The electricity only energy requirement is given as follows:

$$Energy\_Use_{IS=1,i=3,f,y} = \sum_{Prod=1}^{3} \left(Form\_Flow_{IS=1,i=3,y} * Prod\_Share_{IS=1,i,y,Prod}\right) * \sum_{Tech=1}^{2} \left(Proc\_Share_{IS=1,i,y,Prod,Tech} * Fuel\_Use_{IS=1,i,f,Prod,Tech}\right) \quad (196)$$

Table 35. Slab finishing product process shares and energy intensity

	Hot rolled products	Initial process share (base year)	Final process share (end year)	Electricity (million British thermal units per thousand metric tons)
roughing				
	Tech_1	10%	0%	194
	Tech_2	90%	100%	117
finishing				
	Tech_1	20%	0%	328
	Tech_2	80%	100%	285
other				
	skin-pass	12%	12%	27
	pickling	100%	100%	67

Source: U.S. Energy Information Administration

Summing across technologies provides the total demand by fuel for the hot rolling process, as follows:

$$Tot\_Energy\_Use_{IS=1,f,y} = \sum_{Tech} Energy\_Use_{IS=1,Reheat,Tech,f,y} + \sum_{i=1}^{2} Energy\_Use_{IS=1,i,f,y} \quad (197)$$

where

$Tot\_Energy\_Use_{IS=1,f,y}$ = total energy demand, by fuel type f in year y, for the hot rolling step IS=1, in MMBtu;

$Energy\_Use_{IS=1,Hotroll,Tech,f,y}$ = energy use for hot rolling, defined on page 132;

$Energy\_Use_{IS=1,i,f,y}$ = energy use for form i (where 1=blooms, 2=billets, and 3=slabs) by fuel type f in year y. Note that slab production ($i = 3$) only uses electricity.

Cold Rolling: IS = 2

In contrast to other steps in this submodule, cold rolling does not require any technology choice. The material flows generated by the PRODFLOW routine pass through the reduction step and several other sub-steps, allocated according to AISI data. The shares of cold-rolled steel going through these processes are currently held static (Figure 19).

Regional PRODCUR estimates are first summed to provide a national total of cold-rolled steel production, $SumProdCur_{IS=2,y}$.

Cold-rolled steel still goes through the sub-steps of reduction and then galvanizing or electrocleaning. There is one galvanizing process and three alternative electrocleaning processes.

Cold roll reduction: ISX = 1

The reduction step has one technology that is used for all capacity throughout the projection period.

Table 36. Cold roll technology share and energy consumption characteristics in the iron and steel submodule

	Natural gas (million British thermal units per thousand metric tons)	**Electricity (million British thermal units per thousand metric tons)**	**CO_2 emissions (metric tons per thousand metric tons)**
cold roll reduction	986	777	52

Source: U.S. Energy Information Administration

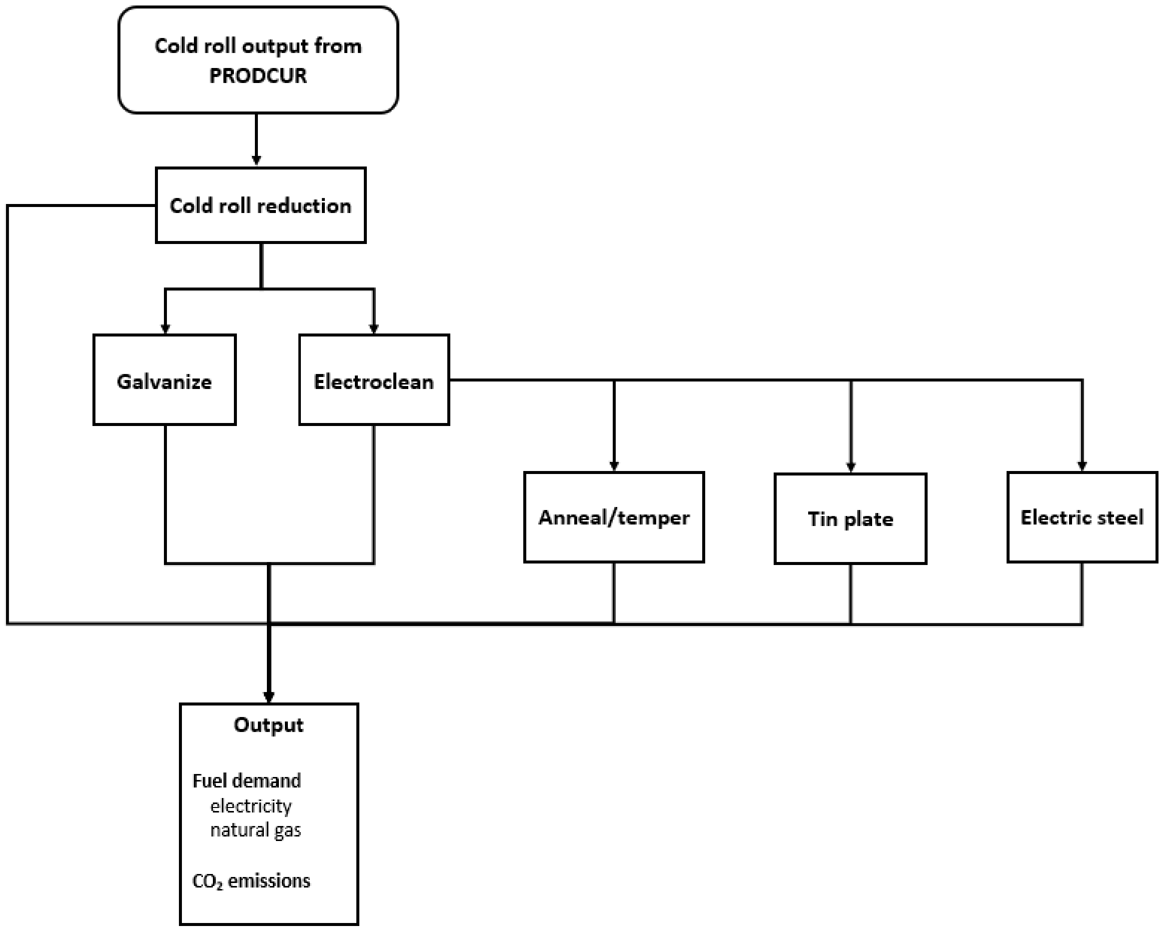
The energy demand for this step is calculated as follows:

$$Tot\_Energy\_Use_{IS=2,f,ISX=1,y} = SumProdCur_{IS=2,y} * Fuel\_Use_{IS=2,f,ISX=1} \tag{198}$$

where

$Fuel\_Use_{IS=2,f,ISX=1}$ = unit energy consumption of fuel f for the cold roll reduction process (ISX=1) of the cold rolling process step (IS=2), in MMBtu/thousand metric tons.

Figure 18. Cold roll technology submodule flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

Galvanizing: ISX = 2

The share of steel passed to the galvanizing stage versus the electrocleaning stage is held fixed at base year levels. The galvanizing step has one technology that is used for all capacity throughout the projection period.

Table 37. Galvanizing energy consumption characteristics in the iron and steel submodule

	Natural gas (million British thermal units per thousand metric tons)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)
galvanize	773	552	41

Source: Consolidated Impacts Modeling System

The steel flow through the galvanizing step is given as follows:

$$Cold\_Galv_y = SumProdCur_{IS=2,y} * Galv\_Shr \tag{199}$$

where

$Cold\_Galv_y$	= metric tons of cold-rolled steel from the galvanizing process in year y; and
$Galv\_Shr$	= historical share of cold-rolled galvanized steel technology, from AISI 2012 data.

The energy demand for the galvanizing step is calculated as follows:

$$Tot\_Energy\_Use_{IS=2,f,ISX=2,y} = Cold\_Galv_y * Fuel\_Use_{IS=2,f,ISX=1} \quad (200)$$

where

$Fuel\_Use_{IS=2,f,ISX=2}$	= unit energy consumption of fuel f for the galvanizing process (ISX=2) of the cold rolling process step (IS=2), in MMBtu/thousand metric tons.

Electrocleaning: ISX = 3

The electrocleaning step is a predecessor to the manufacture of specialized products. Steel that does not pass through the galvanizing step is assumed to pass through electrocleaning, calculated as follows:

$$Cold\_Electro_y = SumProdCur_{IS=2,y} * (1 - Galv\_Shr) \quad (201)$$

where

$Cold\_Electro_y$	= metric tons of cold-rolled steel from the electrocleaning process in year y.

Steel that goes through electrocleaning is first prepared and then split among the anneal/temper and tin plate sub-processes (with negligible amounts going through the electric steel process). The split between these sub-processes is constant throughout the projection period.

Table 38. Electrocleaning allocation shares and process characteristics

	Process share	Natural gas (million British thermal units per thousand metric tons)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)
electrocleaning preparation		0	94	0
anneal/temper	92.8%	903	156	55
tin plate	19.2%	0	571	0
electric steel	<0.1%	2,612	1,738	147

Source: Consolidated Impacts Modeling System

Total electrocleaning energy use is calculated as follows:

$$Energy\_Use_{IS=2,f,ISX=3,f,y} =$$
$$Cold\_Electro_y * Fuel\_Use_{Prep,f,ISX=3} +$$
$$\sum_{Proc=1}^{3} Cold\_Electro * Proc\_Shr_{Proc,ISX=3} * Fuel\_Use_{IS=2,Proc,f,ISX=3} \quad (202)$$

where

$Fuel\_Use_{Prep,f,ISX=3}$	= unit energy consumption of fuel f for electrocleaning preparation (electricity is the only fuel for this sub-process);

$Proc\_Shr_{Proc,ISX=3}$	= the electrocleaned steel share going through sub-process $Proc$ (where 1=anneal/temper, 2=tin plate, and 3=electric steel); and
$Fuel\_Use_{IS=2,Proc,f,ISX=3}$	= unit energy consumption of fuel f for sub-process $Proc$ (where 1=anneal/temper, 2=tin plate, and 3=electric steel) of the electrocleaning step (ISX=3) of the cold rolling process step (IS=2), in MMBtu/thousand metric tons.

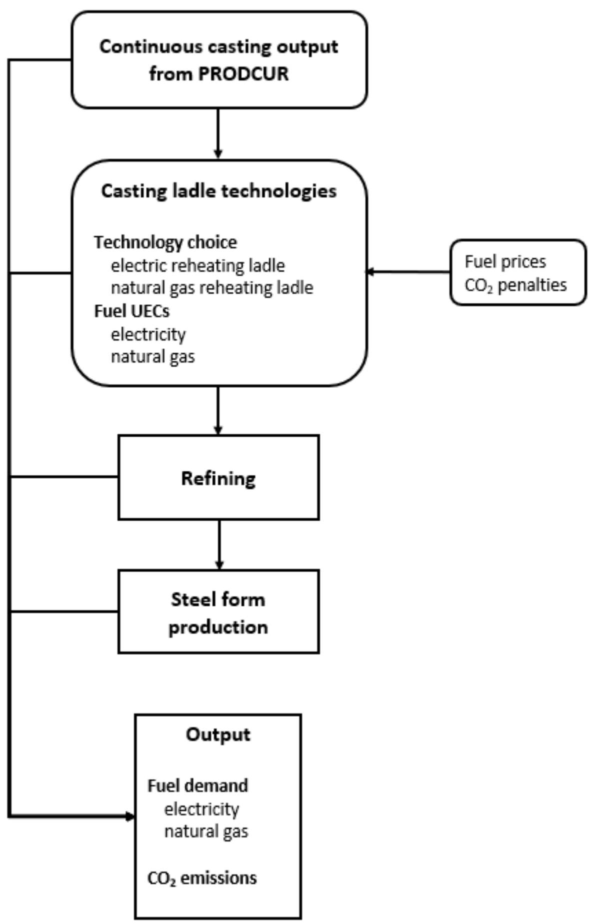
And the total energy demand for the cold rolling step is calculated as follows:

$$Tot\_Energy\_Use_{IS=2,f,y} = \sum_{ISX=1}^{3} Energy\_Use_{IS=2,f,ISX,y} \qquad (203)$$

Continuous casting: IS = 3

Continuous casting comprises three steps: ladle reheating, ladle refining, and steel form production, of which only one (reheating) requires a technology choice (Figure 20).

Figure 19. Continuous casting technology submodule flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

Regional PRODCUR estimates are first summed to provide a national total of cold-rolled steel production, $SumProdCur_{IS=3,y}$.

Table 39. Continuous casting ladle energy and technology characteristics

Technology	Technolog y share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Natural gas (million British thermal units per thousand metric tons)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (tons per thousand metric tons)
electric ladle reheating	99.7%	5,482	19	0	200	0
natural gas ladle reheating	0.3%	4,112	19	1,754	0	92

Source: U.S. Energy Information Administration

Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=3,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the ladle reheating technologies for the added capacity (Table 39), and energy consumption is calculated for the ladle reheating subprocess (ISX=1) as follows:

$$Tot\_Energy\_Use_{IS=3,f,ISX=1,y} = \sum_{Tech=1}^{2} Tot\_Prod\_Tech_{IS=3,Tech,ISX=1,y} * Fuel\_Use_{IS=3,Tech,ISX=1,f} \quad (204)$$

where

$Tot\_Energy\_Use_{IS=3,f,ISX=1,y}$ = total energy use for the continuous casting step (IS=3) ladle reheating subprocess (ISX=1) for fuel f in year y;

$Tot\_Prod\_Tech_{IS=3,Tech,ISX=1,y}$ = thousand metric tons steel production in the ladle reheating subprocess by ladle technology $Tech$; and

$Fuel\_Use_{IS=3,Tech,ISX=1,f}$ = intensity of fuel f in MMBtu per thousand metric tons for technology $Tech$.

Continuous casting ladle refining (ISX=2) applies the electricity intensity from the electric ladle reheating technology (Tech=1, f=1) to all steel going through the continuous casting step:

$$Tot\_Energy\_Use_{IS=3,f=1,ISX=2,y} = SumProdCur_{IS=3,y} * \ Fuel\_Use_{IS=3,ISX=2,f=1} \quad (205)$$

Continuous casting forming (ISX=3) then consumes energy (and emits CO_2) based on the parameters in Table 40, with a single technology used for all capacity in all years.

Table 40. Continuous casting steel form production process characteristics

	Natural gas (million British thermal units per thousand metric tons)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)
steel form production	522	70	27

Source: U.S. Energy Information Administration

Continuous casting steel forming energy use is calculated as follows:

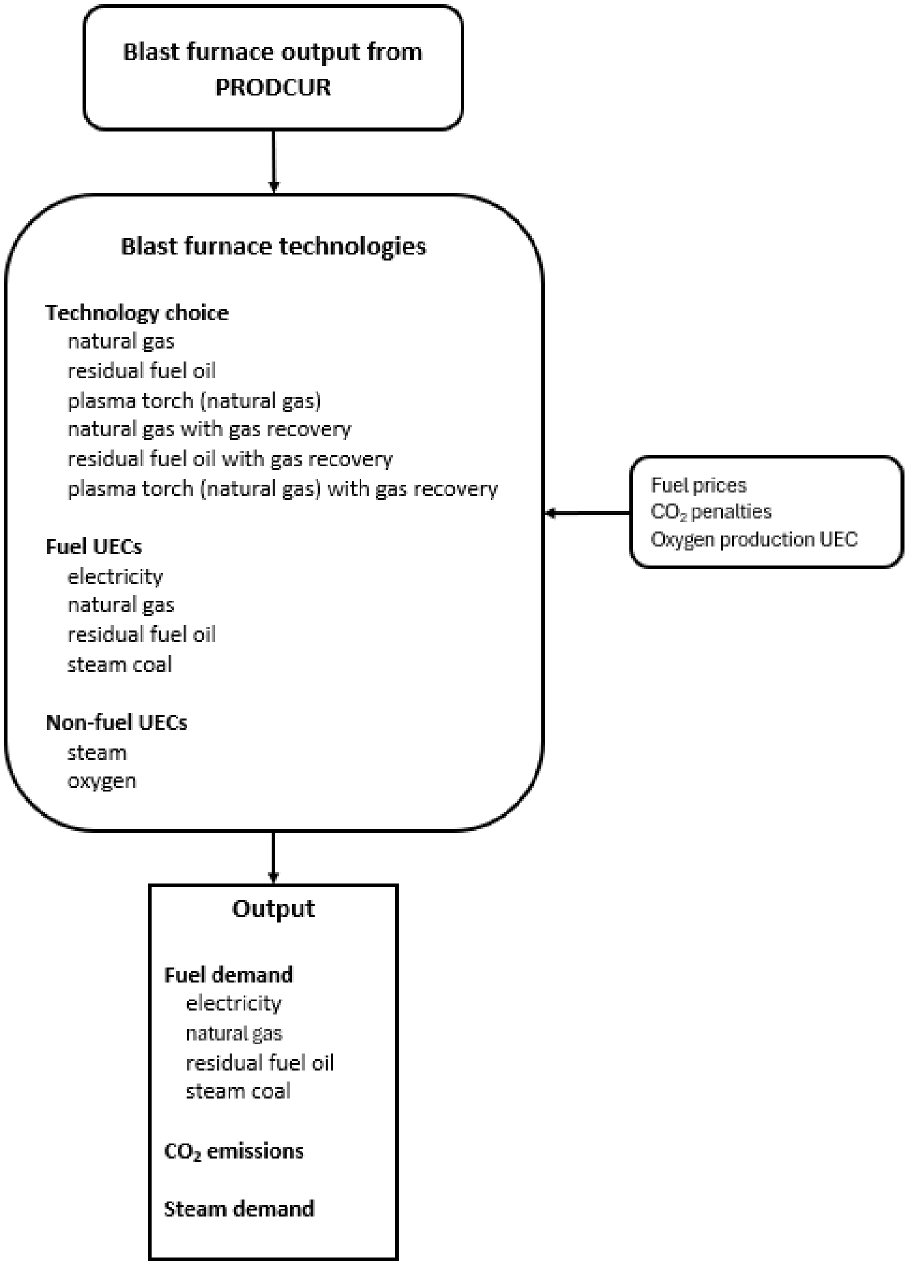
$$Tot\_Energy\_Use_{IS=3,f,ISX=3,y} = SumProdCur_{IS=3,y} * Fuel\_Use_{IS=3,ISX=3,f} \qquad (206)$$

Total energy consumption for the entire continuous casting step is equal to the sum of the energy consumption across the three subprocesses.

Blast furnace/basic oxygen furnace: IS = 4

The blast furnace/basic oxygen furnace (BF/BOF) produces raw steel that is passed to the continuous casting step above. The BF/BOF uses coal, natural gas, heavy fuel oil, and electricity. Steam and oxygen are major non-energy inputs. Fuel use for energy inputs and electricity use for oxygen production are calculated in this step. Fuel use for process steam requirements is calculated in subroutine Steel_BSC (page 148).

Figure 20. Blast furnace technology submodule flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

The physical output for this step is $SumProdCur_{IS=4,y}$, which is equal to the sum of $qBF/BOF_{r,y}$ (page 127) summed across the four census regions:

$$SumProdCur_{IS=4,y} = \sum_{r=1}^{4} prodcur_{IS=4,y} = \sum_{r=1}^{4} qBF/BOF_{r,y} \tag{207}$$

Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=4,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel use, steam, and oxygen consumption can be calculated.

Fuel consumption is calculated for each technology as follows:

$$Energy\_Use_{IS=4,f,Tech,y} = Tot\_Prod\_Tech_{IS=4,Tech,y} * Fuel\_Use_{IS=4,f,Tech} \tag{208}$$

The steam demand for this step is calculated as follows:

$$Steam\_Dmd_{IS=4,Tech,y} = Tot\_Prod\_Tech_{IS=4,Tech,y} * Steam\_Use_{IS=4,Tech} \tag{209}$$

Oxygen demand is calculated as follows:

$$Oxy\_Dmd_{IS=4,Tech} = Tot\_Prod\_Tech_{IS=4,Tech,y} * Oxy\_Use_{\,Tech} \tag{210}$$

where

$Tot\_Prod\_Tech_{IS=4,Tech,y}$	= BF/BOF material output produced using technology $Tech$ in year y;
$Fuel\_Use_{IS=4,f,Tech}$	= unit energy consumption of fuel f using technology $Tech$ in MMBtu/thousand metric tons, which is specified in the input file ironstlx.xlsx and shown in Table 41;
$Steam\_Dmd_{IS=4,Tech,y}$	= gigajoules of steam required for the BF/BOF processes *Tech* in year y;
$Steam\_Use_{IS=4,Tech}$	= steam use in the BF/BOF process for technology $Tech$ in GJ/thousand metric tons, which is specified in the input file ironstlx.xlsx and shown in Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Note: The energy in blast furnace gas (BFG) and coke oven gas (COG), which are produced in the steelmaking process, is deducted from natural gas consumption. A negative value of natural gas consumption means the energy in BFG and COG exceeds natural gas energy consumption.

Table 42;

$Oxy\_Dmd_{IS=4,Tech}$	= metric tons of oxygen required for the technology $Tech$; and
$Oxy\_Use_{\,Tech}$	= oxygen use for technology $Tech$ in metric tons oxygen/thousand metric tons steel, which is specified in the input file ironstlx.xlsx and shown in Table 42.

Total energy consumption for this step, excluding energy used in steam production, is calculated by summing across technologies for this step.

For fuels except electricity, the calculations are as follows:

$$Tot\_Energy\_Use_{IS=4,f\neq Elec,y} = \sum_{Tech=1}^{8} Energy\_Use_{IS=4,f,Tech,y} \tag{211}$$

For electricity, which includes electricity used in the production of oxygen, the calculations are as follows:

$$Tot\_Energy\_Use_{IS=4,f=Elec,y} =$$

$$\sum_{Tech=1}^{8} \left[Energy\_Use_{IS=4,f=Elec,Tech,y} + Oxy\_Dmd_{IS=4,Tech,y} * Oxy\_UEC_{f=Elec}\right] \quad (212)$$

where

$Tot\_Energy\_Use_{IS=4,f,y}$	= BF/BOF energy use for fuel f and year y, excluding steam; and
$Oxy\_UEC_{f=Elec}$	= MMBtu of electricity per metric ton of oxygen produced, using cryogenic air compression and distillation. It is held constant at a value of 0.162318 MMBtu/metric ton.

Energy required to produce steam is not included in this step; fuel use for process steam requirements are calculated in subroutine Steel_BSC (page 148).

Table 41. Blast furnace/basic oxygen furnace energy consumption characteristics

Blast furnace technology	Basic oxygen furnace technology	Technology share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	Natural gas (million British thermal units per thousand metric tons)	Heavy fuel oil (million British thermal units per thousand metric tons)	Coal (million British thermal units per thousand metric tons)
plasma torch	natural gas	89.2%	666,102	279,859	445	894	0	501
coke	natural gas	8.7%	666,102	279,859	451	-2,742	0	636
plasma torch	oil	0.0%	666,102	282,080	432	-2,469	3,362	501
coke	oil	1.8%	666,102	282,080	464	-3,131	388	636
coke	natural gas with recovery	0.1%	675,670	278,902	452	-3,151	0	636
coke	heavy fuel oil with recovery	0.1%	675,670	281,123	464	-3,541	389	636
plasma	natural gas with recovery	0.1%	675,670	278,902	445	487	0	502

plasma	heavy fuel oil with recovery	0.0%	675,670	281,123	433	-2,877	3,363	502

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Note: The energy in blast furnace gas (BFG) and coke oven gas (COG), which are produced in the steelmaking process, is deducted from natural gas consumption. A negative value of natural gas consumption means the energy in BFG and COG exceeds natural gas energy consumption.

Table 42. Blast furnace/basic oxygen furnace non-energy consumption characteristics

Blast furnace technology	Basic oxygen furnace technology	Technology share (base year)	Steam (gigajoules per thousand metric tons)	Oxygen (metric tons per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)
plasma torch	natural gas	89.2%	1,146	154	1,115
coke	natural gas	8.7%	1,153	145	1,211
plasma torch	heavy fuel oil	0.0%	1,146	145	1,196
coke	heavy fuel oil	1.8%	1,153	154	1,220
coke	natural gas with recovery	0.1%	1,154	154	1,190
coke	heavy fuel oil with recovery	0.1%	1,154	145	1,199
plasma	natural gas with recovery	0.1%	1,147	154	1,094
plasma	heavy fuel oil with recovery	0.0%	1,147	145	1,176

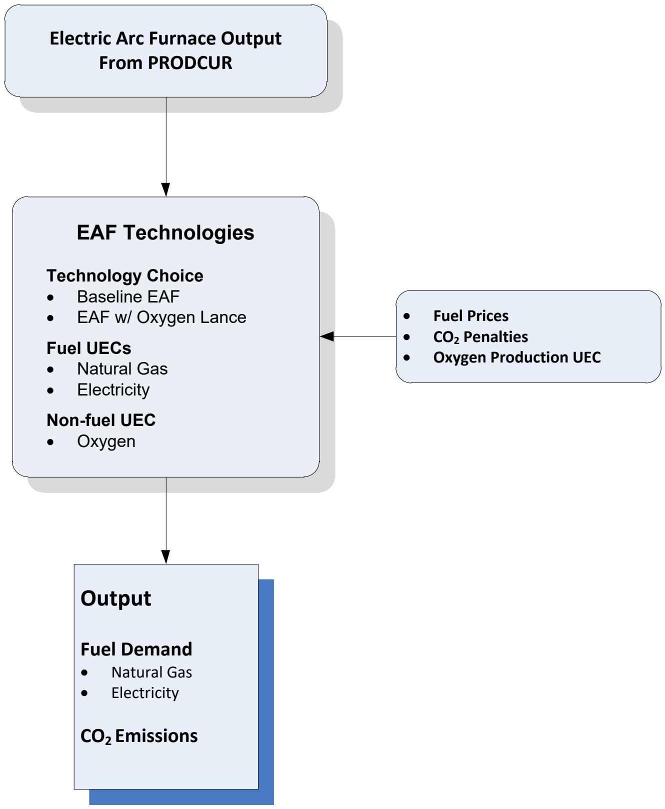
Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Note: The steam demand gets further multiplied by the CIMS steam adjustment factor, set at 2.9 in the ironstlx.xlsx input file.

Electric arc furnace: IS = 5

Like the BF/BOF step above, the electric arc furnace (EAF) step produces raw steel that is passed to the Continuous Casting step. The EAF uses natural gas and electricity. Steam and oxygen are major non-energy inputs. Fuel use for energy inputs and electricity use for oxygen production are calculated in this step. Fuel use for process steam requirements is calculated in subroutine Steel_BSC (page 148).

Figure 21. Electric arc furnace technology submodule flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

The physical output for this step is $SumProdCur_{IS=5,y}$ and is calculated in Subroutine IS_PRODCUR_Breakout (page 123) in which it is equal to the $qEAF_{r,y}$ summed across regions. Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=5,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel use, steam, and oxygen consumption can be calculated by technology (Table 43).

Fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step, as follows:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS=5,f,Tech,y}$, is shown on page 139.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS=5,Tech,y}$, is shown on page 139.
- The calculation for quantity of oxygen demanded by technology and year, $Oxy\_Dmd_{IS=5,Tech}$, is shown on page 139.

Once fuel consumption is calculated by technology, total energy use by fuel can be calculated as follows:

- The calculation for total energy use by fuels other than electricity, $Tot\_Energy\_Use_{IS=5,f\neq Elec,y}$, is shown on page 139.
- The calculation for total electricity use, which includes electricity used in oxygen production, $Tot\_Energy\_Use_{IS=5,f=Elec,y}$, is shown on page 139.

Table 43. Electric arc furnace (EAF) energy and technology characteristics

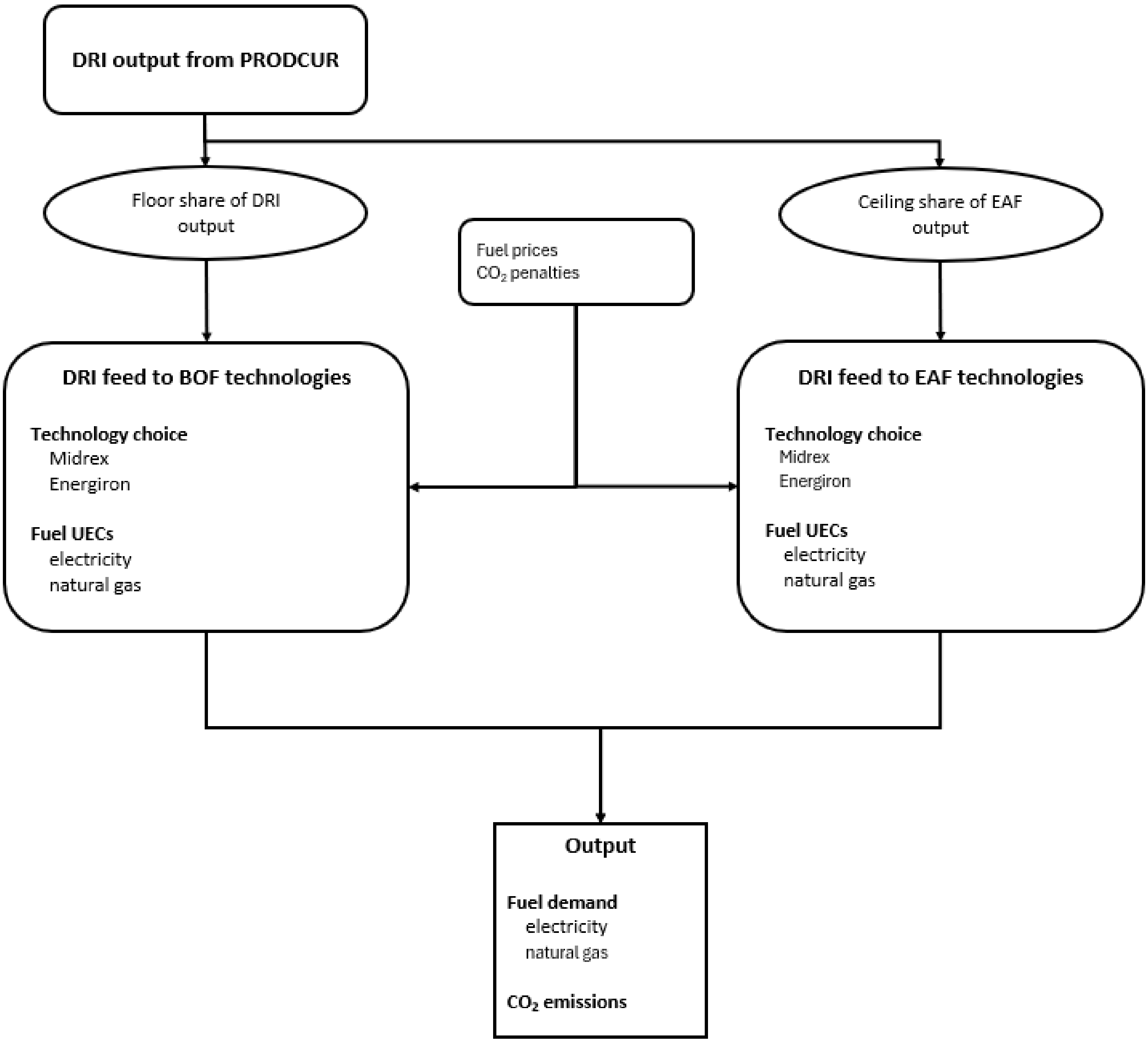
Technology	Technology share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	Natural gas (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Oxygen (metric tons per thousand metric tons)
EAF	27.7%	324,827	39,980	1,673	431	23	0
EAF, oxygen lance	72.3%	324,827	34,268	1,580	431	23	5

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Direct reduced iron: IS = 6

Direct reduced iron (DRI) is used to feed both BF/BOF and EAF processes. DRI currently represents a very small component of iron production, but it shows potential for greater penetration in the future. The EAF uses natural gas and electricity. Steam and oxygen are major non-energy inputs. Fuel use for energy inputs and electricity use for oxygen production are calculated in this step. Fuel use for process steam requirements is calculated in subroutine Steel_BSC (page 148). Figure 21 depicts the flows within this step. The total production of DRI is currently exogenously specified, and PRODFLOW matrix elements are adjusted to ensure that the PRODCUR results match the specified production.

Figure 22. Direct reduced iron submodule flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

The physical output for this step is $SumProdCur_{IS=6,y}$ and is calculated in Subroutine IS_PRODCUR_Breakout (page 123) in which it is equal to the $qEAF_{r,y}$ summed across regions.

The technology choices for producing DRI include the traditional Midrex, Energiron, and a nascent hydrogen-fed DRI technology. All DRI is assumed to be fed (along with scrap steel) into EAFs for steel production and input into the corresponding technology choice subroutine using the technology shares and characteristics are shown in Table 44.

Table 44. Direct reduced iron (DRI) energy and technology characteristics

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	Natural gas (million British thermal units per thousand metric tons)	Hydrogen (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)
DRI to electric arc furnace							
Midrex	44.3%	590,000	147,500	2,371	9,577	0	458
Energiron	55.5%	640,000	147,200	2,560	9,577	0	165
hydrogen	0.1%	422,000	139,577	2,560	0	7,282	0

Source: U.S. Energy Information Administration, based on data from various sources

Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=5,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel use, steam, and oxygen consumption can be calculated by technology. Energy and technology characteristics are shown in Table 43.

Fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step as follows:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 139.
- The calculation for quantity of steam demanded by fuel, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 139.
- The calculation for quantity of oxygen demanded by fuel, technology, and year, $Oxy\_Dmd_{IS,Tech}$, is shown on page 139.

Once fuel consumption is calculated by technology, total energy use by fuel can be calculated:

- The calculation for total energy use by fuels other than electricity, $Tot\_Energy\_Use_{IS,f\neq Elec,y}$, is shown on page 139.
- The calculation for total electricity use, which includes electricity used in oxygen production, $Tot\_Energy\_Use_{IS,f=Elec,y}$ is shown on page 139.

Energy required to produce steam is not included in this step; fuel use for process steam requirements are calculated in subroutine Steel_BSC (page 148).

Coke Production: IS = 7

The physical output for this step is $SumProdCur_{IS=7,y}$ and is calculated in Subroutine IS_PRODCUR_Breakout (page 128) in which it is equal to $qCoke_{r,y}$ summed across regions. The amount of coke actually required to be produced is somewhat different because it must account for net coke imports and the offsetting impact of introducing DRI (which requires no coke) to the BOF system. Like the cold rolling step (IS=2), coke production requires no technology choice; it is simply an accounting of the requirement for domestically produced coke and the energy required to manufacture it.

First, the net coke requirement must be calculated by subtracting the avoided production stemming from the introduction of DRI, as follows:

$$Net\_Coke_y = qCoke_y - DRI\_BOF_y * Coke\_Conversion \tag{213}$$

where

Net_Coke = net coke required to produce the estimated production of BF/BOF steel;

DRI_BOF_y = amount of DRI introduced to the BF/BOF system, in thousand metric tons; and

$Coke\_Conversion$ = 0.39, constant conversion factor to estimate the metric tons of coke production avoided.

The amount of BF/BOF steel produced is then adjusted to estimate non-DRI production. This result is used to estimate and constrain subsequent adjustments from net coke imports:

$$NON\_DRI\_BOF_y = qBF\_BOF_y - DRI\_BOF_y \tag{214}$$

where

qBF_BOF_y = total production of BF/BOF steel (IS = 4); and

NON_DRI_BOF = total non-DRI production of BF/BOF steel.

Net imports of coke (NI) can increase or decrease the amount of coke required to be domestically produced. NI is estimated through regression, based on historical data, and is determined by its lagged value and changes in the production of BF/BOF steel. The estimation of NI is:

$$NI_y = NI_{y-1} - 0.3872 * \left(NI_{y-1} - NI_{y-2}\right)$$
$$+ 0.1239 * \left(NON\_DRI\_BOF_y - NON\_DRI\_BOF_{y-1}\right) \tag{215}$$

where

NI_y = total net imports of coke in year *y*.

Because the above NI_y estimation equation is unbounded, it is necessary to impose an additional constraint so that the projection does not produce an unrealistic estimate of imports or exports. Accordingly, the function is constrained so that when it evaluates as a negative (that is, exports), it does not exceed a specified percentage of the net coke requirement for making BOF steel. This requirement is currently set at 10%, which represents the maximum historical share of negative net imports (exports). This percentage is intended to acknowledge the decreasing reliance on BF/BOF production in the United States, and the expected limitation on the availability of coke for export. The constraint is imposed as follows:

$$C\_NI_y = MAX\left[NI_y, \left(-Net\_Coke_y * Max\_Pct\right)\right] \tag{216}$$

where

C_NI_y = constrained net imports of coke in year *y*; and

Max_Pct = maximum percentage of domestically produced coke available for export.

Accounting for the coke production avoided through the use of DRI and the adjustment to production from imports or exports, the total coke production requirement is expressed as follows:

$$Coke\_Prod_y = Net\_Coke_y - C\_NI_y \tag{217}$$

where

$Coke\_Prod_y$ = total coke production in thousand metric tons in year *y*.

The energy and other inputs required to produce a metric ton of coke are obtained from a third party report[44] and summarized in Table 45.

Table 45. Coke production energy consumption characteristics

Electricity	Natural gas	Heavy fuel oil	Metallurgical coal	Blast furnace gas	Coke oven gas (input)	Coke oven gas (output)	Steam (gigajoules per thousand metric tons)
121.3	15.4	11.0	42,659	115.7	3,401	-9,579	826

Source: Consolidated Impacts Modeling System

Note: Units in MMBtu per thousand metric tons, except for steam. Additionally, the steam demand gets further multiplied by the CIMS steam adjustment factor, set at 2.9 in the ironstlx.xlsx input file.

The energy and material requirement for the coke production step is then given by the following:

$$Tot\_Energy\_Use_{IS=7,f,y} = Coke\_Prod_y * Fuel\_Use_{f,y} \tag{218}$$

This steam demand for this step is given as follows:

$$Steam\_Dmd_{IS=7,y} = Coke\_Prod_y * Steam\_Use_y \tag{219}$$

Subroutine Steel_BSC: Energy for steam production

Process steam is used in the production of BF/BOF steel, DRI, and coke. This steam is produced by either conventional boilers or CHP systems. Steam produced by CHP is also used to generate electricity, which is used to offset electricity demand in other process steps.

Total steam demand is first calculated as follows:

$$Tot\_Steam_y = BTU\_Conv * \sum_{IS \in 4,6,7} Steam\_Dmd_{IS,y} \tag{220}$$

where

Tot_Steam = total process steam required by all steps (MMBtu);

[44] Figure F-1, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model*, FOCIS Associates, Inc., October 2005.

$Steam\_Dmd_{IS,y}$	= is calculated on 139; and
BTU_Conv	= unit conversion constant that converts gigajoules to MMBtu.

Steam production is then allocated between conventional and CHP systems as follows:

$$Boil\_Steam_y = Tot\_Steam_y * Boil\_Share \tag{221}$$

$$CHP\_Steam_y = Tot\_Steam_y * (1 - Boil\_Share) \tag{222}$$

where

$Boil\_Steam$	= total steam produced by conventional boilers (gigajoules);
CHP_Steam	= total steam produced by CHP systems (gigajoules); and
$Boil\_Share$	= fraction of total steam produced by boilers, linearly decreasing from 55% in the base year to 25% in the final year.

The technologies associated with boiler and CHP systems are described in the following table. The fuel shares have been calibrated to agree with MECS estimates. The allocation of steam production to each of the technologies is exogenously specified in the initial and final years of the projection, and the shares for the intervening years are calculated by linear interpolation between those points.

Table 46. Steam and combined-heat-and-power (CHP) production shares and energy intensities

	Technology share		Electricity (million British thermal units per gigajoule steam)	Natural gas (million British thermal units per gigajoule steam)	Heavy fuel oil (million British thermal units per gigajoule steam)	Coal (million British thermal units per gigajoule steam)	CO_2 emissions (metric tons per gigajoule steam)
	2018	2050					
Boiler technologies (IX = 1) of which:	**55%**	**25%**					
natural gas boiler	27%	20%	0	1.19	0	0	0.062
coal boiler	70%	15%	0	0	0	1.16	0.113
heavy fuel oil boiler	1%	0%	0	0	1.16	0	0.089
coal boiler, with carbon capture and storage	1%	15%	0.05	0	0	1.48	0.012
natural gas boiler, with CCS	1%	50%	0.04	1.31	0	0	0.007
CHP technologies (IX = 2) of which:	**45%**	**75%**					
natural gas turbine	90%	20%	-0.11	1.33	0	0	0.070
coal turbine	9%	1%	-0.11	0	0	1.30	0.126
heavy fuel oil turbine	1%	1%	-0.11	0	1.33	0	0.102
natural gas, backpressure steam turbine with CCS	0%	78%	-0.07	1.47	0	0	0.008

Source: U.S. Energy Information Administration

The energy required to produce steam is calculated as follows:

$$Boiler\_Energy\_Use_{f,y} =$$

$$\sum_{Tech} Boil\_Steam_{Tech,y} * Tech\_Shr_{Tech,y} * Fuel\_Use_{Tech,f} \quad (223)$$

$$CHP\_Energy\_Use_{f,y} = \sum_{Tech} CHP\_Steam_{Tech,y} * Tech\_Shr_{Tech,y} * Fuel\_Use_{Tech,f} \quad (224)$$

$$Steam\_Fuel\_Dmd_{f,y} = Boiler\_Energy\_Use_{f,y} + CHP\_Energy\_Use_{f,y} \quad (225)$$

where

$Tech\_Shr_{Tech,y}$ = exogenously specified share of boiler or CHP technology $Tech$ used to produce steam; and

$Fuel\_Use_{Tech,f}$ = unit energy consumption fuel f for steam production, in MMBtu/GJ of steam produced as shown in Table 46.

In the case of CHP systems, the negative figure calculated for electricity represents the energy content of generated electricity. For reporting purposes, this content is converted to kilowatthours of electricity generation as follows:

$$Elec\_Gen_y = \frac{CHP\_Energy\_Use_{Elec,y}}{(3412\ Btu/kWh)} * 10^6 \quad (226)$$

Subroutine TECH_STEP: Industry energy demand

Total energy demand by fuel is computed directly in subroutine TECH_STEP. Energy consumption is the sum of fuel demands. First, fuel demand for each process step is summed as follows:

$$Non\_Steam\_Energy\_Use_{f,y} = \sum_{IS=1}^{7} Energy\_Use_{IS,f,y} \quad (227)$$

Adding boiler and CHP fuel consumption yields total energy consumption, as follows:

$$Total\_Q_{f,y} = Boiler\_Energy\_Use_{f,y} + CHP\_Energy\_Use_{f,y} + Non\_Steam\_Energy\_Use_{f,y} \quad (228)$$

where

$Total\_Q_{f,y}$ = total demand for energy, by fuel and year;

$Boiler\_Energy\_Use_{f,y}$ and $CHP\_Energy\_Use_{f,y}$ are defined above; and

$Energy\_Use_{IS,f,y}$ = total demand for energy, by fuel f, within each process step in MMBtu.

Unique iron and steel submodule calculations

Creating a dynamic PRODFLOW matrix

With a dynamic PRODFLOW, the mass of material going through each process step changes based on exogenous factors. Some PRODFLOW coefficients are subject to change, either by linking to exogenous factors such as fuel price, or by direct adjustment to reflect the future introduction of new capacity. The dynamic elements are as follows:

1. share of cold-rolled steel, expressed as a percentage of hot-rolled production
2. BF/BOF capacity is sensitive to changing coal prices; increasing coal price leads to retirement of BF/BOF and corresponding replacement with EAF steel production
3. if coal prices do not increase or increase weakly, BF/BOF capacity retires annually at a rate of 1.75%, but BF/BOF capacity cannot decrease below 10% of total steel production capacity
4. share of EAF versus BF/BOF
5. DRI inputs to EAF—driven by low natural gas prices
6. coke inputs into the BF/BOF stage

Cold-rolled steel share

Cold-rolled steel percentage is inferred from other MAM output: the value of output of fabricated metals, machinery, and transportation equipment are tentatively considered proxies for the demand for cold-rolled steel, and construction is considered a proxy for hot-rolled steel demand. A proxy value is first calculated as follows:

$$Cold\_Proxy_{r,y} = \left[\frac{Outind_{FabMet,r,y} + Outind_{Mach,r,y} + Outind_{TranEq,r,y}}{Outind_{FabMet,r,y} + Outind_{Mach,r,y} + Outind_{TranEq,r,y} + Outind_{Const,r\,y}}\right] \tag{229}$$

where

$Outind_{xx,r,y}$ = value of shipments, obtained from MAM, for industry xx, region r, and year y. Industries in xx include fabricated metals (FabMet), machinery (Mach), transportation equipment (TranEq), and construction (Const).

This value is then indexed to the base year, as follows:

$$Cold\_Index_{r,y} = \left[\frac{Cold\_Proxy_{r,y}}{Cold\_Proxy_{r,baseyear}}\right] \tag{230}$$

Regional indices are then applied to the baseline dynamic PRODFLOW elements read in from the ironstlx.xlsx input file.

Share of EAF versus BOF

The EAF-BOF split is currently initialized using regional elements of the PRODFLOW, adjusted using fuel price changes, and then renormalized so that their sum is equivalent to the base year sum of coefficients.

More specifically, all the output from the EAF and BOF steps is assumed to flow into the continuous casting step. According to the coefficients in the input/output matrix above, one metric ton of casting output (in Region 1) would require 0.754 metric tons of EAF production and 0.310 metric tons of BOF production—a total of 1.064 metric tons of input for the region.

There are significant regional differences in these elements: regions 2 and 3 each require 1.113 metric tons of material input at the casting step, and region 4 apparently suffers no waste, requiring 1.0 metric tons of EAF production (without any BOF) for each metric ton produced in casting.

To adjust the applicable PRODFLOW elements, the relative shares of EAF and BOF technologies are incrementally adjusted year-to-year by incorporating the year-to-year change in coal price. This adjustment is computed as a year-to-year percentage decline in BOF production, which is then in turn replaced by an equivalent increase in EAF production. At a minimum, each projection year the BOF production decreases by 0.5%, but if the increase in coal price is large enough, the decline will be more than 0.5%.

DRI inputs to EAF

Beginning with this revised submodule, direct reduced iron (DRI) is included as a component of the I/O (that is, PRODFLOW) matrix. In contrast to other elements of the production process, initial DRI production is exogenously specified and flows into either BF or EAF production output. The coefficients dictating the flows of DRI to the subsequent production steps are calculated based on projected production or capacity expansion in each region. They are then converted into a share of regional production for each of the steelmaking processes. The exogenous estimate of DRI production by region is as follows, based on review of available literature regarding industrial production plans:

Table 47. Direct reduced iron production by region

Million metric tons per year	Region 1	Region 2	Region 3	Region 4
2018	0	0	4.5	0
2020	0	1.6	4.50	0

Source: U.S. Energy Information Administration

After the final exogenous expansion of DRI, future DRI additions are a function of BOF capacity. The following should be noted:

- The PRODFLOW matrix is intended to calculate the demand for output from a subsidiary step, and this approach backs into the coefficients, forcing the submodule to generate a pre-determined demand.
- Because DRI may be used in both EAFs and BFs, DRI should have a non-zero coefficient in the BF-BOF column of the **A** matrix.
- To accommodate these concerns, we constrain DRI inputs to EAF to a user-specified ceiling and to specify a minimum floor for DRI inputs to BFs.
- After calculating the tonnage of DRI devoted to each subsequent process, the figures are converted to represent the fraction of BF or EAF output. These converted figures are the PRODFLOW factors that populate the I/O matrix.
- A detailed description of how DRI is allocated between BF and EAF is provided above, in the discussion of the submodule's material flows.

Coke inputs into the BF/BOF stage

The PRODFLOW elements associated with coke production were recalibrated to ensure that the overall (national) impact would result in a production ratio more in line with the expected range of 0.35 to 0.40 metric tons of coke per metric ton of BOF steel. There elements are benchmarked to provide results that agree with USGS estimates of blast furnace steel production in the base year.

Originally, these PRODFLOW elements were stipulated, falling linearly over a set time frame to a minimum value. The current model approach is to link the coke element to the changes in the BOF PRODFLOW element (which essentially specifies the share of steel production that comes from BOFs).

$$Coke\_Fact_{r,y} = Coke\_Fact_{r,y-1} * \left(1.0 + Coke\_Calib * \left[\left(\frac{BOF\_Fact_{r,y}}{BOF\_Fact_{r,y-1}}\right) - 1.0\right]\right) \quad (231)$$

where

$Coke\_Fact_{r,y}$ = PRODFLOW element for coke production, by region *r*, in year *y*;

$Coke\_Calib$ = calibration constant, 0.60, that governs the sensitivity of changes in coke production to changes in blast furnace steel production; and

$BOF\_Fact_{r,y-1}$ = PRODFLOW element for BOF steel production.

Using dynamic PHDRAT to generate PRODX

To convert dollar amounts to physical units for industries other than steel, a value is calculated to represent the baseline volume of production, using the value of output from MAM and various sources of physical shipments data for the base year. The resulting value per metric ton of product is considered fixed for the projection. This static value (PHDRAT) is subsequently used to convert MAM projections of steel output from dollars to metric tons.

In contrast, the PHDRAT for iron and steel is dynamic, based on the share of steel that is cold-rolled. Cold-rolled steel is processed more than hot-rolled steel and is therefore presumably more expensive. The unit price (dollars per metric ton) of steel represents a weighted average price of the two forms of steel, and the unit price of cold-rolled steel represents a premium over the unit price of hot-rolled steel because of additional processing. If the mix of hot-rolled and cold-rolled steel changes, the weighed unit price will change, which implies the static PHDRAT assumption should change as well. First, a base price is defined as follows:

$$BasePrice_r = \frac{\frac{PRODVX_{r,Base}}{PRODX_{r,Base}}}{(1 + \alpha_{r,Base}\beta)} \quad (232)$$

$$NewPrice_{r,y} = BasePrice_r\ (1 + \alpha_{r,y}\beta) \quad (233)$$

$$PRODX_{r,y} = \frac{PRODVX_{r,y}}{NewPrice_{r,y}} \quad (234)$$

$PHDRAT_{r,y}$ is similar to $PHDRAT$ on page 52, but it is now dynamic, as follows:

$$PHDRAT_{r,y} = \frac{PRODX_{r,y}}{PRODVX_{r,y}} \tag{235}$$

where

$\alpha_{r,y}$ = is the fraction of steel shipments represented by cold-rolled steel for region *r* in a given year *y* and is defined as the $Cold\_Index_{r,y}$ (see page 151) times a base cold roll fraction read in from the ironstlxx.xlsx input file; and

β = is the cold-rolled price premium, set to 0.15.

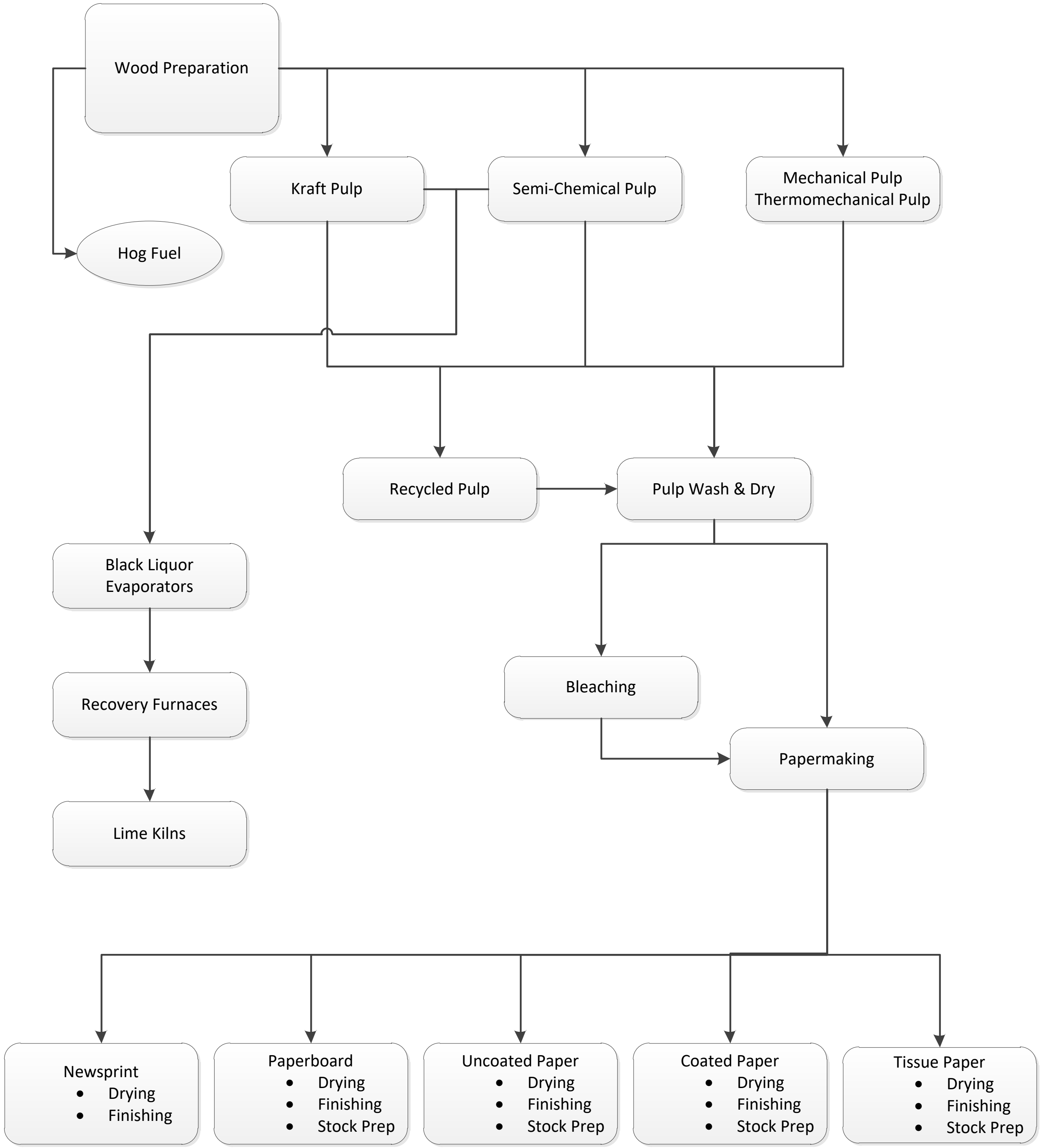
The result of this calculation is that the weighted steel price, based on a gradually increasing share of cold-rolled steel, trends upward over the projection period. The regional changes in the share of hot-rolled versus cold-rolled steel calculated in this section also have an effect on the input/output coefficient matrices (PRODFLOW).

PULP AND PAPER INDUSTRY

Pulp and paper submodule flow

The pulp and paper submodule, like other energy-intensive industry submodules, is based on estimated flows of material across several process steps to ultimately meet final demand projections generated by the MAM (Figure 23).

Figure 23. Detailed pulp and paper submodule flow in the Industrial Demand Module



Source: U.S. Energy Information Administration

Process flow determination

The pulp and paper submodule separately addresses material flows through each of a series of component steps. These steps represent the intermediate (and occasionally competing) processes that are required to produce the volume of paper output projected by the MAM. The subroutine

PP_ProdcurBreakout calculates these material flows, and it is very similar to IS_PRODCUR Breakout (page 123).

Subroutine PP_Proxy

For two of the PRODCUR process steps papermaking and mechanical pulping, the flows need to be subdivided to feed different subprocesses. Papermaking is divided into five product types, and mechanical pulping is divided into two separate processes by Subroutine PP_PROXY (page 181).

Subroutine PP_ProdcurBreakout

The PRODCUR calculation produces estimates of material flow for seven process steps and four census regions. The pulp and paper submodule requires the flows to be aggregated into national totals and then broken out into sub-steps that will be used as inputs to the technology choice submodules.

Table 48 presents the individual process steps in the pulp and paper submodule, the number of subprocesses within each step, and the subprocess step indices used in the model code. Each of these model steps will be discussed separately, following the determination of productive capacity and its allocation among competing technologies.

Table 48. Pulp and paper submodule process steps and subprocess step indices

Model step	Associated PRODCUR elements	Number of processes	Process step (PRODCUR) index (IS)	PRODFLOW step index
wood prep	wood prep	1	1	7
kraft pulp	kraft pulp	1	2	6
semi-chemical pulp	semi-chemical pulp	1	3	5
mechanical pulp	mechanical pulp	1	4	4
thermomechanical pulp		1	5	
recycled pulp	papermaking, virgin pulp	1	6	1, 4–6
pulp wash and dry	virgin and recycled pulp	2	7, 8	3–6
bleaching	bleaching	1	9	2
newsprint	papermaking	2	10, 11	1
paperboard		3	12–14	
coated paper		3	15–17	
uncoated paper		3	18–20	
tissue paper		3	21–23	
evaporators	black liquor	1	24	N/A
lime kilns		1	25	
recovery furnaces		1	26	

Source: Consolidated Impacts Modeling System

Physical output is determined by subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Physical output is broken into 26 products. Unlike steel, there is not a one-to-one correspondence between PRODCUR and steps in the paper and pulp submodule. Physical flows are as follows:

$$qWoodPrep_{r,y} = prodcur_{IS=1,r,y} \tag{236}$$

$$qKraftPulp_{r,y} = prodcur_{IS=2,r,y} \tag{237}$$

$$qSemiChemPulp_{r,y} = prodcur_{IS=3,r,y} \tag{238}$$

$$qMechPulp_{r,y} = prodcur_{IS=4,r,y} = Mech\_Share_y * \ qTotalMechPulp_{r,y} \tag{239}$$

$$qThermoMechPulp_{r,y} = prodcur_{IS=5,r,y} = \left(1 - Mech\_Share_y\right) * qTotalMechPulp_{r,y} \tag{240}$$

$$qRecycledPulp_{r,y} \ \ = prodcur_{IS=6,r,y}$$

$$= qTotalPaper_{r,y} - (qKraftPulp_y + \ qSemiChemPulp_y + \ qTotalMechPulp_y) \tag{241}$$

$$qPulpWash_{r,y} \ \ = prodcur_{IS=7,r,y}$$

$$= qKraftPulp_{r,y} + qSemiChemPulp_{r,y} + qTotalMechPulp_{r,y} + qRecycledPulp_{r,y} \tag{242}$$

$$qPulpDry_{r,y} = prodcur_{IS=8,r,y} = qPulpWash_{r,y} = qTotalPaper_{r,y} \tag{243}$$

$$qPulpBleach_{r,y} = prodcur_{IS=9,r,y} \tag{244}$$

where

$prodcur_{IS=m,r,y}$ = physical production flow for pulp and paper submodule step $IS = m$, region r and year y;

$qWoodPrep_{r,y}$ = quantity of wood in thousand metric tons processed in wood prep step for region r and year y;

$qKraftPulp_{r,y}$ = quantity of pulp in thousand metric tons processed in Kraft process for region r and year y;

$qSemiChemPulp_{r,y}$ = quantity of pulp in thousand metric tons processed in semi-chemical process for region r and year y;

$qMechPulp_{r,y}$ = quantity of pulp in thousand metric tons processed in mechanical pulp process for region r and year y;

$qThermoMechPulp_{r,y}$ = quantity of pulp in thousand metric tons processed in thermomechanical process for region r and year y;

$qRecycledPulp_{r,y}$ = quantity of recycled pulp in thousand metric tons for region r and year y;

$qTotalPaper_{r,y}$ = quantity of total paper produced, (paperboard, coated, uncoated, tissue, and newsprint) for region r and year y;

$qPulpWash_{r,y}$ = quantity of pulp in thousand metric tons processed in pulp wash process step for region r and year y;

$qPulpDry_{r,y}$ = quantity of pulp in thousand metric tons processed in pulp wash process step for region r and year y; and

$qPulpBleach_{r,y}$ = quantity of pulp in thousand metric tons processed in pulp wash process step for region r and year y.

Total paper physical flow is available, but paper is needed by specific product: newsprint, paperboard, coated paper, uncoated paper, and tissue paper. Subroutine PP_PROXY (page 181) computes product shares by year so that paper product production can be calculated. For example, the quantity of paperboard is defined by:

$$qPaperboard_{r,y} = \ prodcur_{IS=12,r,y} = \ prodcur_{IS=13,r,y} = \ prodcur_{IS=14,r,y}$$

$$= PaperboardShare_{y} * \ qTotalPaper_{r,y} \qquad (245)$$

where

$qPaperboard_{r,y}$ = total physical quantity of paperboard produced;
$PaperboardShare_{y}$ = share of total paper production that is devoted to paperboard;
$qTotalPaper_{r,y}$ = is defined on page 157;
$prodcur_{IS=12,r,y}$ = total physical quantity of paperboard processed in the drying process;
$prodcur_{IS=13,r,y}$ = total physical quantity of paperboard processed in the finishing process; and
$prodcur_{IS=14,r,y}$ = total physical quantity of paperboard processed in the stock prep process.

All paper types except newsprint have drying, finishing, and stock prep process. Newsprint has drying and finishing only.

Finally, the Kraft and semi-chemical pulping processes produce black liquor as a byproduct. These physical quantities are available nationally because the calculation is entirely within the pulp and paper submodule, which is a national-level submodule, as follows:

$$qBlackLiquor_{y} = \ prodcur_{IS=24,y} = \ prodcur_{IS=25,y} = \ prodcur_{IS=26,y} \qquad (246)$$

where

$qBlackLiquor_{y}$ = total black liquor available from the Kraft and semichemical pulping processes;

$prodcur_{IS=24,y}$ = total physical quantity of black liquor processed in black liquor evaporators;

$prodcur_{IS=25,y}$ = total physical quantity of black liquor associated with lime kiln processing; and

$prodcur_{IS=26,y}$ = total physical quantity of black liquor processed in recovery furnaces.

The following sections describe the individual manufacturing processes addressed by the pulp and paper submodule. Each set of technology attributes is derived primarily from the CIMS dataset. In some instances, the technology choice submodule considers a truncated subset of technologies, due to close similarity of costs and unit energy demands.

Wood Prep: IS = 1

The main operations employed for wood preparation include debarking, chipping, and conveying. Short logs are transported to pulping mills where the bark is treated with chemicals in a rotating drum. The force of friction of bolts rubbing against each other and the edge of the drum removes the bark, which is then used as a fuel. In some cases, hydraulic debarking may be used, but this process is more energy intensive. After debarking, the logs are chipped, most often in a radial chipper.

The physical output for this step, $SumProdCur_{IS=1,y}$, is calculated by summing $prodcur_{IS=1,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=1,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in Table 49.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step as follows:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS=1,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS=1,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, total energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS=1,f,y}$ is shown on page 139.

Table 49. Wood prep (IS=1) base year technology shares and attributes

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)
debarkers and cutters					
ring style	91.3%	93,568	3,744	76	0
rosser head	8.4%	93,568	3,744	76	0
biodegradable	0.3%	280,705	4,043	71	0

Source: Consolidated Impacts Modeling System

In addition to the pulpwood produced in this process are waste and the combustible byproduct, hog fuel[45], which is used to produce steam and electricity. The amount of hog fuel produced is calculated as follows:

$$HogFuel_y = Energy\_Use_{IS=1,h,y} = \left[\left(Hog\_Pulp * qVirginPulp_y\right) - qTotalPaper_y\right] * Hog\_Waste * Hog\_Heat \quad (247)$$

where

[45] Hog fuel derives its name from the Norwegian word for *chopped* or *hacked*: *hogge*. Rest assured that no porcine units were injured in the making of this product.

$Tot\_Energy\_Use_{IS=1,h,y}$= energy use for hog fuel in the wood prep process in year *y*;
$HogFuel$ = combustible wood byproduct, in GJ;

$qVirginPulp_y = qKraftPulp_y + qSemiChemPulp_y + qTotalMechPulp_y$ virgin (nonrecycled) pulp in metric tons;
Hog_Pulp = metric tons of wood required for each metric ton of pulp, from American Forest Product Association (AFPA) data;
Hog_Heat = heat content of hog fuel, in GJ per metric ton, from MECS; and
Hog_Waste = percentage of wood waste that is allocated to hog fuel, calibrated so that base year totals agree with MECS estimates.

The hog fuel created in this step is subsequently used to generate electricity and produce steam.

Kraft Pulp: IS = 2

The Kraft pulping process involves treating wood chips and sawdust with a sodium sulfide and sodium hydroxide solution that breaks the bonds that link lignin to the cellulose. The highly alkaline chemical and wood mixture is digested (or more simply, cooked) with steam under pressure. Digestion may be either a continuous process or treated in discontinuous batches.

The physical output for this step, $SumProdCur_{IS=1,y}$, is calculated by summing $prodcur_{IS=2,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=2,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in Table 50.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step, as follows:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS=2,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, total energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 50. Kraft pulping technologies and energy consumption

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Steam use (gigajoules per thousand metric tons)
batch digester	9.0%	164,552	6,582	837	0	2,811
batch with heat recovery	3.4%	167,927	6,718	838	0	2,682
batch with heat recovery and computer control	5.0%	170,161	6,806	838	0	2,553
batch with rapid displacement heating superbatch	4.0%	173,700	6,950	841	0	2,068
continuous digester	29.9%	159,216	6,370	1,082	0	2,109
continuous with computer control	48.8%	161,431	6,459	1,082	0	2,065

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

For every metric ton of Kraft pulp produced, a constant quantity of black liquor is produced as a byproduct. The black liquor is subsequently processed through lime kilns and evaporators and burned off in recovery furnaces, producing steam and electricity (details are available starting on page 173). The amount of black liquor produced is given as follows:

$$BLiquor_{IS=2,y} = \sum_{Tech} Tot\_Prod\_Tech_{Tech,y} * BLKLIQ_{IS=2} \tag{248}$$

where

$BLiquor_{\ IS=2,y}$ = combustible black liquor, in GJ, from the Kraft process IS=2; and

$BLKLIQ_{\ IS=2}$ = conversion factor for the Kraft process in GJ/thousand metric tons, calibrated to ensure that base year values agree with those reported by MECS.

Semi-Chemical Pulp: IS = 3

The neutral sulfite semi-chemical (NSSC) pulping process is used at a number of U.S. mills to produce courser-grade products such as corrugated board, which has a yield of about 75% of the wood raw material. In NSSC pulping, wood chips are softened by briefly cooking them in a neutral sodium or ammonium sulfite solution and then separating the fibers in a refiner. Digestion may be either a continuous process or treated in discontinuous batches.

The physical output for this step, $SumProdCur_{IS=3,y}$, is calculated by summing $prodcur_{IS=3,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=3,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in Table 51.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, total energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 51. Semi-chemical pulping technologies and energy consumption

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Steam use (gigajoules per thousand metric tons)
batch digester	99.8%	138,224	5,529	1,731	0	1,558
batch digester with heat recovery	0.1%	142,935	5,717	1,732	0	1,158
continuous digester	0.1%	109,773	4,392	1,731	0	1,539

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

As with Kraft pulp, for every metric ton of semi-chemical pulp produced, a constant quantity of black liquor is produced as a byproduct. This black liquor is subsequently processed through lime kilns and evaporators, and it is burned off in recovery furnaces, producing steam and electricity. The calculation for the amount of black liquor produced in the semi-chemical process, $BLiquor_{IS=3,y}$, is the same as in the Kraft process and calculated on page 161.

Mechanical Pulp: IS = 4

The pulp and paper submodule separates mechanical pulping processes into conventional mechanical pulping and thermomechanical pulping, which have different technology attributes. This division is based on historical data from AFPA[46] and is projected using changes in production indices of newsprint and tissue.

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[46] American Forest & Paper Association, *2013 Statistical Summary of Paper, Paperboard, and Pulp*, Table 15.

In the stone groundwood process, debarked short logs (roundwood) are fed into wet stone grinders by hydraulic rams. The abrasion of the grinding wheel against the wood physically separates the wood fibers. The grinding process usually is automatic and continuous. Refiner mechanical pulping (RMP) uses chips in lieu of roundwood and produces paper with higher strength than conventional groundwood because of less damage to the fibers in the pulping process.

The amount of mechanical pulp is calculated slightly differently from the other process steps.The physical output for this step, $SumProdCur_{IS=4,y}$, is calculated by summing $prodcur_{IS=4,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=1,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in Table 52.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 52. Mechanical pulping technologies

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Steam use (gigajoules per thousand metric tons)
stone grinder	28.2%	238,873	11,941	2,302	0	0
mechanical refiner	3.3%	304,310	12,173	3,026	0	0
size two refiner	47.3%	484,244	19,370	2,807	0	-1,128
size two high speed refiner	21.1%	512,214	20,484	2,802	0	-1,128

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

In this process, a supply of steam is produced, which is used to offset steam demand in other processes. In contrast with Kraft and semi-chemical pulping processes, mechanical processes do not produce black liquor as a byproduct.

Thermo-Mechanical Pulp: IS = 5

The thermomechanical process (TMP) was developed as a modification of the RMP process. In TMP, the wood chips are steamed for several minutes under pressure and subsequently refined in one or two stages. A further development of thermo-mechanical pulp is chemical thermo-mechanical pulp (CTMP), in which the wood chips are infused with a chemical treatment before the grinding. The refined wood pulp, although still weaker than chemical pulp, makes a stronger paper than conventional mechanical pulp with only a small sacrifice in yield, but it requires a lot of energy to make.

The physical output for this step, $SumProdCur_{IS=5,y}$, is calculated by summing $prodcur_{IS=5,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=5,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in Table 53.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 53. Thermo-mechanical pulping technologies

Technology	**Tech share (base year)**	**Capital costs (dollars per thousand metric tons capacity)**	**Operations and maintenance costs (dollars per year per thousand metric tons capacity)**	**Electricity (million British thermal units per thousand metric tons)**	**CO_2 emissions (metric tons per thousand metric tons)**	**Steam use (gigajoules per thousand metric tons)**
chemical thermo-mechanical pulp (CTMP)	92.3%	508,456	20,340	2,529	0	0
thermo-mechanical pulp (TMP)	7.7%	554,134	22,167	1,266	0	0

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Recycled Pulp: IS = 6

Recycled pulp is manufactured from waste paper that is processed into paper stock. Pulping is accomplished through violent agitation and shearing action performed at high temperatures. Paper produced from recycled pulp is generally weaker than papers from virgin materials because of the breakdown of the used fibers and loss of fiber bonding. Technology characteristics are shown in Table 54.

The physical output for this step, $SumProdCur_{IS=5,y}$, is calculated by summing $prodcur_{IS=6,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=6,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in Table 53.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 54. Recycled pulp technologies

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Steam use (gigajoules per thousand metric tons)
recycled with deinking	99.8%	78,995	3,160	503	0	1,186
recycled with flotation deinking	0.1%	446,464	17,857	1,222	0	1,076
recycled with explosion deinking	0.1%	510,861	20,441	377	0	890

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Pulp Wash and Dry: IS = 7, 8

After pulping and bleaching, the pulp is blended with additives and processed into the stock that is used for paper manufacturing. Before heat drying, pulps are sent to a pressing section to squeeze out as much water as possible though mechanical means. The pulp is compressed between two rotating rolls where the extent of water removal is determined by the design of the machine and its running speed. When the pressed pulp leaves the pressing section, it has about a 65% moisture content. In an integrated mill, this pulp is sent to the papermaking section. In a non-integrated mill, the pulp is further dried so that it can be baled for transportation to the next mill for paper manufacturing. Such pulp, termed market pulp, is dried to about a 10% moisture content in steam-heated dryers.

The physical output for this step, $SumProdCur_{IS=k,y}$, is calculated by summing $prodcur_{IS=7,r,y}$ and $prodcur_{IS=8,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=1,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in Table 55.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption is calculated by technology, energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 55. Pulp washing and drying technologies

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Steam use (gigajoules per thousand metric tons)
washing: IS = 7						
drum washer	75.0%	103,515	4,142	217	0	0
diffusion washer	25.0%	103,515	4,142	168	0	0
drying: IS = 8						
steam dryer	80.0%	180,174	7,207	683	0	4,433
steam and electric vapor dryer	20.0%	212,156	8,487	874	0	4,109

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Bleaching: IS = 9

Raw pulp still contains an appreciable amount of lignin and other discoloration. To produce light or white colors preferred for many products, it must be bleached. Bleaching is normally done in several stages. Chlorination and oxidation removes any residual lignin. A number of bleaching agents may be used and are applied in a stepwise fashion within a bleaching sequence. These agents include chlorine gas, chlorine dioxide, sodium hypochlorite, hydrogen peroxide, and oxygen. Technology characteristics are shown in Table 56.

The physical output for this step, $SumProdCur_{IS=9,y}$, is calculated by summing $prodcur_{IS=9,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=9,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in Table 52.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 56. Bleaching technologies

Technology	**Tech share (base year)**	**Capital costs (dollars per thousand metric tons capacity)**	**Operations and maintenance costs (dollars per year per thousand metric tons capacity)**	**Electricity (million British thermal units per thousand metric tons)**	**CO_2 emissions (metric tons per thousand metric tons)**	**Steam use (gigajoules per thousand metric tons)**
chlorine dioxide (ClO_2) bleach	60.4%	146,931	5,877	238	0	2,048
hypochlorite bleach	0.1%	111,856	4,474	175	0	2,049
hypochlorite bleach with computer control	0.1%	113,422	4,564	175	0	1,928
oxy-delignification with first stage ClO_2	26.0%	177,643	7,106	322	0	2,254
oxy-delignification with second stage ClO_2	13.4%	146,931	5,877	300	0	2,255

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Each pulp product serves as the stock for many types of paper products. Newsprint can use feedstock from each of the pulping processes. Other paper products, including tissue paper, uncoated and coated paper, and paperboard are made from blends of different pulps and varying degrees of stock inputs. Total paper production, estimated in PRODCUR, is divided into the five paper product types according to the *Paper_Share* calculation in Subroutine PP_PROXY (page 181).

Newsprint: IS = 10, 11

The physical output for this step, $SumProdCur_{IS=k,y}$, is calculated by summing $prodcur_{IS=10,r,y}$ and $prodcur_{IS=11,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=\mathrm{k},y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in Table 57.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Table 57. Newsprint technologies

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Steam use (gigajoules per thousand metric tons)
newsprint drying: IS = 10						
electric paper dryer	10.0%	198,965	7,960	4,037	0	0
steam dryer	89.8%	188,945	7,558	79	0	4,089
steam dryer with computer control	0.1%	191,183	7,647	79	0	3,821
high intensity dryer	0.1%	113,169	4,527	79	0	3,888
newsprint form and finish: IS = 11						
press and finish	99.7%	513,288	20,535	1,732	0	0
press and induction heat finish	0.1%	544,671	22,058	1,772	0	0

nip press and finish	0.1%	543,306	21,736	1,740	0	-433
nip press and induction heat finish	0.1%	581,622	23,269	1,779	0	-433

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Paperboard: IS = 12, 13, 14

This segment includes corrugated cardboard and packaging materials. Technology characteristics are shown in Table 58.

The physical output for this step, $SumProdCur_{IS=l,y}$, is calculated by summing $prodcur_{IS=12,r,y}$, $prodcur_{IS=13,r,y}$, and $prodcur_{IS=14,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=l,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in Table 58.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 58. Paperboard technologies

Technology	**Tech share (base year)**	**Capital costs (dollars per thousand metric tons capacity)**	**Operations and maintenance costs (dollars per year per thousand metric tons capacity)**	**Electricity (million British thermal units per thousand metric tons)**	**CO_2 emissions (metric tons per thousand metric tons)**	**Steam use (gigajoules per thousand metric tons)**
drying: IS = 12						
steam dryer	99.6%	169,574	6,782	21	0	4,980
steam with computer control	0.1%	171,597	6,866	21	0	4,653
steam with vapor recovery	0.1%	171,597	6,866	31	0	4,427

high intensity steam	0.1%	101,567	4,062	21	0	4,735
form press and finish: IS = 13						
form press and finish	99.6%	416,535	16,661	1,430	0	0
form nip press and finish	0.1%	441,560	17,663	1,442	0	-860
efficient press and finish	0.1%	525,530	21,021	1,336	0	0
efficient nip press and finish	0.1%	550,556	22,022	1,404	0	-860
stock preparation: IS = 14						
conical refine and screen	79.6%	158,163	6,327	1,164	0	0
disc refine and screen	20.4%	223,344	8,934	793	0	0

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Uncoated Paper: IS = 15, 16, 17

Uncoated paper is typically used for letterheads, copy paper, or printing paper. Most types of uncoated paper are surface sized to improve their strength. Such paper is used in stationery and lower quality leaflets and brochures[47].

The physical output for this step, $SumProdCur_{IS=m,y}$, is calculated by summing $prodcur_{IS=15,r,y}$, $prodcur_{IS=16,r,y}$, and $prodcur_{IS=17,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=m,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in Table 59.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

[47] http://www.paperonline.org/paper-making/paper-production/paper-finishing/coated-or-uncoated

Table 59. Uncoated paper technologies, energy consumption, and non-energy characteristics

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Steam use (gigajoules per thousand metric tons)
drying: IS = 15						
steam dryer	99.7%	218,925	8,757	69	0	4,779
infrared radiation dryer	0.1%	221,836	8,874	69	0	4,466
high intensity steam	0.1%	131,126	5,245	69	0	4,545
steam with high humidity hood	0.1%	232,060	9,282	69	0	4,404
form press and finish: IS = 16						
form press and finish	99.7%	575,688	23,029	1,159	0	0
form nip press and finish	0.1%	609,622	24,387	1,170	0	-539
efficient press and finish	0.1%	723,468	28,941	1,065	0	0
efficient nip press and finish	0.1%	757,393	30,299	1,130	0	-539
stock preparation: IS = 17						
conical refine and screen	99.9%	158,163	6,327	1,115	0	0
efficient disc refine and screen	0.1%	223,344	8,934	764	0	0

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Coated Paper: IS = 18, 19, 20

Coating is a process by which paper or board is coated with an agent to improve brightness or printing properties. By applying precipitated calcium carbonate (PCC), china clay, pigment, or adhesive, the coating fills the miniscule pits between the fibers in the base paper, giving it a smooth, flat surface, which can improve the opacity, luster, and color-absorption ability[48]. Technology characteristics are shown in Table 60.

The physical output for this step, $SumProdCur_{IS=u,y}$, is calculated by summing $prodcur_{IS=18,r,y}$, $prodcur_{IS=19,r,y}$, and $prodcur_{IS=20,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=u,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fossil fuel, steam, and oxygen consumption can be calculated by technology.

[48] http://www.paperonline.org/paper-making/paper-production/paper-finishing/coated-or-uncoated

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 60. Coated paper technologies, energy consumption, and non-energy characteristics

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Steam use (gigajoules per thousand metric tons)
drying: IS = 18						
steam dryer	99.6%	218,925	8,757	62	0	4,335
infrared radiation dryer	0.1%	236,601	9,452	2,124	0	0
high intensity steam	0.1%	131,126	5,245	62	0	4,122
high intensity electric	0.1%	135,060	5,404	2,021	0	0
form press and finish: IS = 19						
form press and finish	99.4%	575,688	23,029	989	0	0
form nip press and finish	0.1%	609,622	24,387	996	0	-459
efficient press and finish	0.2%	723,468	28,941	909	0	0
efficient nip press and finish	0.2%	757,393	30,299	962	0	-459
stock preparation: IS = 20						
disc refine and screen	99.8%	158,163	6,327	952	0	0
efficient disc refine and screen	0.2%	223,344	8,934	653	0	0

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Tissue Paper: IS = 21, 22, 23

This segment covers a wide range of tissue and other hygienic papers for use in households or on commercial and industrial premises. Examples are toilet paper and facial tissues, kitchen towels, hand towels, and industrial wipes.

Not all paper is coated. Uncoated paper is typically used for letterheads, copy paper, or printing paper. Most types of uncoated paper are surface sized to improve their strength. Such paper is used in stationery and lower quality leaflets and brochures[49].

The physical output for this step, $SumProdCur_{IS=v,y}$, is calculated by summing $prodcur_{IS=21,r,y}$, $prodcur_{IS=22,r,y}$, and $prodcur_{IS=23,r,y}$ across regions in subroutine PP_Prodcur_Breakout, which is very similar to the IS_PRODCUR breakout (page 123). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $SumProdCur_{IS=v,y}$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in are shown in Table 61.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 61. Tissue paper technology characteristics

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	Natural gas (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Steam use (gigajoules per thousand metric tons)
drying: IS = 21							
steam dryer	99.8%	170,503	6,820	391	3,533	213	2,484
steam dryer with computer control	0.1%	172,539	6,903	392	3,300	199	2,320
steam with high humidity hood	0.1%	180,734	7,229	392	3,253	196	2,287
form press and finish: IS = 22							
form press and finish	99.9%	509,983	20,397	467	0	0	0
efficient press and finish	0.1%	637,479	25,496	377	0	0	0

[49] http://www.paperonline.org/paper-making/paper-production/paper-finishing/coated-or-uncoated

stock preparation: IS = 23							
conical refine and screen	79.7%	158,163	6,327	492	0	0	0
efficient disc refine and screen	20.3%	223,344	8,934	336	0	0	0

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Chemicals recovery

Pulp mills commonly employ a chemical recovery processes to reclaim spent chemicals from the pulping process. The most common reclaimed spent chemical is spent cooking liquor, referred to as weak black liquor, from the pulp washers, and it is routed to a chemical recovery process that involves concentrating the weak black liquor, combusting organic compounds, reducing inorganic compounds, and reconstituting the cooking liquor. The weak black liquor is first directed through a series of evaporators to increase the solids content to about 50% to form strong black liquor. The strong black liquor is further concentrated in direct or non-direct contact evaporators, also called concentrators.

Evaporators: IS = 24

Black liquor is a byproduct that flows from the Kraft and semi-chemical pulping steps. This byproduct flows to evaporators, recovery furnaces, and finally, in the form of green liquor, to lime kilns. The pulp and paper submodule generates material flows of black liquor solids in units of GJ, not mass or volume, and the following processes to treat black liquor are based on an implicit (and constant) level of dilution. The conversion factor that specifies the amount of black liquor generated by the pulping processes has been calibrated so it agrees with the base year MECS estimate. The total flow of black liquor to evaporators is given as follows:

$$qBlackLiquor_y = \sum_{IS=2}^{3} BLiquor_{IS,y} \tag{249}$$

where

$BLiquor_{IS}$ = quantity of black liquor solids, in GJ, produced in the Kraft and semi-chemical pulping processes (IS = 2, 3) (page 161).

Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $qBlackLiquor_y$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in are shown in Table 62.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 62. Black liquor evaporator technologies, energy consumption, and non-energy characteristics

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Steam use (gigajoules per thousand metric tons)
basic evaporator	16.0%	65,962	2,638	44	0	4,073
evaporator with computer control	50.0%	66,758	2,670	44	0	4,016
evaporator with standalone concentrator	10.0%	72,558	2,902	44	0	3,713
evaporator with integrated concentrator	24.0%	69,260	2,770	44	0	2,620

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Lime Kilns: IS = 25

This process step treats the green liquor produced by the recovery furnace through the addition of lime (CaO) to convert the Na_2CO_3 into sodium hydroxide (NaOH). Following treatment, CaCO3 is collected as a precipitate, which is washed, dried, and calcined in a lime kiln to produce CaO, which is then recycled. Although it is green liquor, not black liquor that is treated in lime kilns, the relationship is considered constant and the kiln technology characteristics are linked to black liquor flows.

Total flow of black liquor to evaporators is the same as the total flow of black liquor to recovery furnaces (page 175). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $qBlackLiquor_y$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in are shown in Table 63.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, energy use by fossil fuels and electricity can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

In addition to fossil fuels and electricity, lime kilns also use wood waste. Energy use is computed for wood waste separately, as follows:

$$Wood\_Kiln_y = EnergyUse_{IS=25,f=hogfuel,y} = \sum_{Tech} Tot\_Prod\_Tech_{Tech,y} * H\_Fuel_{Tech} \quad (250)$$

where

$Wood\_Kiln$ = quantity of hog fuel, in GJ, used in lime kilns; and

H_Fuel_{Tech} = energy intensity of wood waste, in GJ/thousand metric tons, for lime kilns technology *Tech*.

Table 63. Lime kiln technologies, energy consumption, and non-energy characteristics

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	Natural gas (million British thermal units per thousand metric tons)	Heavy fuel oil (million British thermal units per thousand metric tons)	Coal (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Hog fuel (gigajoules per thousand metric tons)
basic natural gas lime kiln	69.8%	12,096	483	36	2,209	0	0	117	0
natural gas kiln with flash dryer	29.9%	12,096	483	37	1,541	0	0	82	0
oil kiln with flash dryer	0.1%	12,096	483	37	0	1,516	0	111	0
coal kiln with flash dryer	0.1%	79,796	3,191	37	385	0	1,327	146	0
oil and wood waste kiln	0.1%	79,796	3,191	37	0	378	0	159	1, 399

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Recovery Furnaces: IS = 26

The recovery furnace combusts all organic compounds in black liquor and reduces all Na_2SO_4 to Na_2S. Concentrated black liquor is sprayed into the recovery furnace where organic compounds are combusted. Molten inorganic salts, referred to as smelt, collect in a char bed at the bottom of the furnace. Smelt is drawn off and dissolved in weak wash water in the smelt dissolving tank to form a solution of carbonate salts called green liquor, which is primarily Na_2S and Na_2CO_3.

Total flow of black liquor to evaporators is the same as the total flow of black liquor to recovery furnaces (page 175). Subroutine Step_Capacity (page 95) calculates how much additional productive capacity, if any, is needed to produce the physical output equal to $qBlackLiquor_y$. Once any additional productive capacity has been calculated, the subroutine Logit_Calc (page 97) chooses the technologies for the added capacity. Once technologies for the new capacity are chosen, fuel and steam consumption can be calculated by technology. Technology characteristics are shown in are shown in Table 64.

Fossil fuel consumption is calculated for each technology as it is for the blast furnace/basic oxygen furnace step:

- The calculation for energy use by fuel, technology, and year, $Energy\_Use_{IS,f,Tech,y}$, is shown on page 140.
- The calculation for quantity of steam demanded by step, technology, and year, $Steam\_Dmd_{IS,Tech,y}$, is shown on page 140.

Once fossil fuel and electricity consumption are calculated by technology, energy use by fuel can be calculated; $Tot\_Energy\_Use_{IS,f,y}$ is shown on page 140.

Table 64. Recovery furnace technologies, energy consumption, and non-energy characteristics

Technology	Tech share (base year)	Capital costs (dollars per thousand metric tons capacity)	Operations and maintenance costs (dollars per year per thousand metric tons capacity)	Electricity (million British thermal units per thousand metric tons)	CO_2 emissions (metric tons per thousand metric tons)	Steam use (gigajoules per thousand metric tons)
furnace with 600 pounds per square inch gauge (psig) cogeneration	14.1%	165,491	6,620	-780	0	-6,950
furnace with direct contact evaporator	16.6%	154,203	6,169	111	0	-5,600
furnace with low odor configuration	43.7%	154,203	6,169	111	0	-6,500
furnace with low odor configuration and computer control	4.7%	154,203	6,169	111	0	-6,600
furnace with high solids firing	4.7%	161,913	6,477	111	0	-6,950
furnace with 900 psig cogeneration	16.3%	164,204	6,568	-1,074	0	-6,950

Source: U.S. Energy Information Administration, based on Consolidated Impacts Modeling System

Steam and electric power generation

Pulp and paper mills use spent steam from on-site CHP units as a source of heat for their processes such as pulping (pulp cooking) and pulp and paper drying. CHP units are rapidly replacing traditional boilers because of their added benefit of producing electricity as well. Steam is needed to cook the pulp and dry wet paper on the paper machines. Instead of producing steam at a wide range of pressures needed for the different unit operations, high pressure steam is generated in a boiler and run through a turbine to generate electric power. The lower pressure steam that exits the turbines is then used throughout the pulp and paper plant for all heating needs.

This set of calculations is intended to be used in place of the boiler, steam, and cogeneration (BSC) component of the IDM, and the results have been calibrated to agree with the base year MECS estimates. Following this section is a series of notes that describe the rationale and approach to this calibration.

Gross and net steam

The step IS=26 generates steam, which can be used to offset other processes' steam demand. However, energy needed to generate steam in IS=26 must also be accounted for in total steam demand and in electricity generated from combined heat and power.

Net steam is the amount of steam needed in the paper industry, after deducting steam produced by recovery boilers. Gross steam is net steam plus steam demand from IS=26, which is equal to -1 times steam supply. The first step in this section is to estimate the total process steam that needs to be generated to meet the steam demand of the preceding process steps 1 through 25:

$$Proc\_Steam_y = (1.0 - Recycle\_Pct) * \left(\sum_{IS=1}^{25} \sum_{Tech_i=1}^{Maxi} Steam\_Dmd_{Tech_i,IS,y} \right) \tag{251}$$

where

$Proc\_Steam_y$ = quantity of process steam, in GJ, required for all pulp and paper processes, excluding black liquor recovery furnaces;

$Recycle\_Pct$ = share of generated steam that is recycled for low-intensity applications, calculated through offline analysis to be 34%;

$Tech\ _i$ = process technology index for step *IS;* and

Max_i = maximum number of technology choices for step *IS.*

This calculation represents the process steam required in the first 25 steps, but it does not include the offsetting impact of steam produced by the black liquor recovery furnaces (IS = 26), described above. This quantity is redefined as follows:

$$BL\_Steam_y = -\left(\sum_{Tech=1}^{Maxi} Steam\_Dmd_{Tech,IS=26,y} \right) \tag{252}$$

where

BL_Steam = quantity of steam, in GJ, produced by black liquor recovery furnaces, in year y expressed as a negative demand.

Although BL_Steam can be used to offset steam demand in steps 1 through 25, the steam represented by BL_Steam also needs to be produced. For this, the $PAPER\_STEAM\_GRS$ variable denotes gross steam: total steam demand for steps 1 through 25 and the demand for steam in IS 26, which is assumed to be equal to the steam supplied. $PAPER\_STEAM\_GRS$ is defined as:

$$PAPER\_STEAM\_GRS_y = \ Proc\_Steam_y + \sum_{Tech=1}^{Maxi} Steam\_Dmd_{Tech,IS=26,y} \tag{253}$$

To find net process steam, which is process steam that comes from fossil fuels, take steam demand less steam supply from IS=26 less renewable steam from hog fuel:

$$Net\_Proc\_Steam_y = BTU\_Conv \ * \left[Proc\_Steam_y + BL\_Steam_y - Net\_HogFuel_y * Bio\_Eff\right] \tag{254}$$

where

$Net\_Proc\_Steam_y$	= quantity of process steam, in MMBtu, produced by fossil fuels;
BTU_Conv	= unit conversion constant that converts GJ to MMBtu;
Bio_Eff	= boiler efficiency of biofuels, hardcoded in the in the IDM at 69%;
$Net\_HogFuel_y$	= $HogFuel_y - Wood\_Kiln_y$ = hog fuel available to generate steam in CHP systems, in GJ, where
$HogFuel_y$	= combustible wood waste produced by the wood prep step (IS = 1), in GJ, defined on page 159; and
$Wood\_Kiln_y$	= amount of hog fuel consumed by lime kilns (IS = 25), in GJ, defined on page 175.

The net process steam is then allocated between conventional boilers and CHP systems as follows:

$$Steam\_Boil_y = Net\_Proc\_Steam_y * Boil\_Shr_y \tag{255}$$

$$Steam\_CHP_y = Net\_Proc\_Steam_y * \left(1.0 - Boil\_Shr_y\right) \tag{256}$$

where

$Steam\_Boil_y$	= quantity of process steam, in GJ, produced in boilers in year y;
$Steam\_CHP_y$	= quantity of process steam, in GJ, produced in CHP systems in year y; and
$Boil\_Shr_y$	= share of total net process steam produced in boilers in year y, set at 15% in 2018, and declining linearly to 5% in 2050.

Fuel demand for boilers and CHP

The demand for fossil fuels in boilers is calculated as follows:

$$Boil\_Fuel\_Dmd_{fo,y} = Steam\_Boil_y * Boil\_FShare_{fo} * Boil\_intensity_{fo} \tag{257}$$

where

$Boil\_Fuel\_Dmd_{fo,y}$	= demand for fossil fuels in boilers (GJ) for process for fossil fo and year y;
$Boil\_intensity_{fo}$	= boiler energy intensity, in GJ of fuel input/GJ of steam output for fossil fuel fo; and

$Boil\_FShare_{fo,y}$ = allocation of steam production among fossil fuels for process for fossil fuel fo and year y.

The boiler characteristics are provided in Table 65.

Table 65. Pulp and paper fossil fuel-fired boiler information

Boiler technology	Tech share		Natural gas (gigajoules fuel per gigajoules steam)	Heavy fuel oil (gigajoules fuel per gigajoules steam)	Coal (gigajoules fuel per gigajoules steam)
	2018	2050			
natural gas	97%	100%	1.25	0.0	0.0
heavy fuel oil	2%	0%	0.0	1.25	0.0
coal	1%	0%	0.0	0.0	1.23

Source: U.S. Energy Information Administration

Similarly, the demand for fossil fuels in CHP systems is given as follows:

$$CHP\_Fuel\_Dmd_{fo,y} = Steam\_CHP_y * CHP\_FShare_{fo} * CHP\_f\_intensity_{fo} \quad (258)$$

The electricity generated by fossil fuel is:

$$CHP\_Elec_{fo,y} = Steam\_CHP_y * CHP\_FShare_{fo} * CHP\_elec\_out_{fo} \quad (259)$$

where

$CHP\_Fuel\_Dmd_f$ = demand for fossil fuels in CHP systems for fossil fuel *fo*, in GJ;

CHP_FShare_f = allocation of steam production among differing CHP technologies for fossil fuel fo;

$CHP\_f\_intensity_{f,y}$ = CHP energy intensity, in GJ of fuel input/GJ of steam output for fossil fuel fo (natural gas, oil, and coal) and year y;

$CHP\_Elec_{fo,y}$ = electricity generated by CHP systems, in GJ, for fossil fuel fo; and

$CHP\_elec\_out_{f,y}$ = GJ of fuel input/GJ of electricity output for fossil fuel fo and year y.

The characteristics of fossil fuel-fired CHP systems are provided below. As with boiler systems, the fuel shares remain constant, but the energy intensities change over time to reflect assumed transitions to more advanced CHP systems.

Table 66. Pulp and paper fossil fuel-fired CHP intensity, 2018 and 2050

CHP technology	Tech share		Electricity produced (gigajoules electricity per gigajoules steam)	Natural gas (gigajoules fuel per gigajoules steam)	Heavy fuel oil (gigajoules fuel per gigajoules steam)	Coal (gigajoules fuel per gigajoules steam)
	2018	2050				
natural gas	67%	19%	-0.1108	1.4020	0.0	0.0
natural gas with regenerative burners	18%	73%	-0.1385	1.4197	0.0	0.0

coal	13%	0%	-0.1108	0.0	0.0	1.3698
coal with regenerative burners	0%	7%	-0.1385	0.0	0.0	1.3870
heavy fuel oil	2%	0%	-0.1108	0.0	1.4020	0.0
heavy fuel oil with regenerative burners	0%	1%	-0.1385	0.0	1.4197	0.0

Source: U.S. Energy Information Administration

Added to the electricity generated by fossil fuels is that generated by black liquor and hog fuel:

$$CHP\_Elec_{Bio,y} = \left(Net\_HogFuel_y * Bio\_Eff\right) * CHP\_EIntens_{Bio} \; + \; ElecGen\_pap26 \tag{260}$$

where

$CHP\_Elec_{Bio,y}$ = electricity generated by CHP systems from biofuels, in GJ;

$CHP\_EIntens_{Bio}$ = CHP electric intensity, in GJ of electricity/GJ steam for biofuels, set at the value of -0.1385; and

$ElecGen\_pap26$ = net electricity generated from selected CHP technologies in IS=26. This quantity is equal to the share of technologies 1 and 6 times the amount of electricity generated in the respective steps, expressed as a negative value. These quantities can be found in the ironstlx.xlsx input file on the paper tab. If neither technology 1 nor 6 is selected, this quantity is 0.

The amount of bio-based fuel demand for CHP is:

$$CHP\_Fuel\_Dmd_{Bio,y} = \left(\sum_{Tech=1}^{Max_i} Steam\_Dmd_{Tech,IS=26,y} + HOGSteam\right) * \frac{1}{Bio_{Eff}} \tag{261}$$

The fuel needed to produce $ElecGen\_pap26$ is accounted for in steam demand for IS=26.

The total electricity generated by CHP systems is then calculated as follows:

$$Tot\_CHP\_Elec_y = CHP\_Elec_{Bio,y} + \sum_{fo} CHP\_Elec_{fo,y} \tag{262}$$

The sum of demand for fossil fuels and net electricity across boilers, CHP, and other heat and power needs are passed to the main fuel consumption array, ENPMQTY. The sum of the biomass consumed is passed to the renewable fuel consumption, ENPRQTY. The gross steam consumption ($PAPER\_STEAM\_GRS$) is added to the intermediate fuel array, ENPIQTY.

Subroutine PP_PROXY

The MAM provides estimates of the total production of paper, but it does not break out all the components of this production. Because the technologies and processes involved in producing different types of paper products differ, the pulp and paper submodule constructs a set of normalized indices to allocate total paper production among five product types: (1) newsprint, (2) paperboard, (3) coated paper, (4) uncoated paper, and (5) tissue. These indices are based on MAM estimates of the following sectors' output.

Table 67. Macroeconomic Activity Module sector outputs

NAICS code	Industries	PP_Proxy_x
3221	Pulp, paper, and paperboard mills	PP_Proxy_1
32221	Paperboard container manufacturing	PP_Proxy_2
322x	All other NAICS 322 categories	PP_Proxy_3
323	Printing and related support	PP_Proxy_4
5111	Newspapers, periodicals, and books	PP_Proxy_5

Source: U.S. Energy Information Administration, U.S. Department of Commerce, U.S. Census Bureau, North American Industry Classification System (2017)—United States (Washington, DC, 2017)

For each product type (*prx*), a production index is defined as follows:

newsprint ($prx = 1$):

$$PP\_ProdNDX_{prx=1,y} = \frac{PP\_Proxy\_4_y}{PP\_Proxy\_5_y} \tag{263}$$

paperboard ($prx = 2$):

$$PP\_ProdNDX_{prx=2,y} = \frac{PP\_Proxy\_2_y}{PP\_Proxy\_1_y} \tag{264}$$

coated paper ($prx = 3$):

$$PP\_ProdNDX_{prx=3,y} = \frac{PP\_Proxy\_4_y}{PP\_Proxy\_1_y} \tag{265}$$

uncoated paper ($prx = 4$):

$$PP\_ProdNDX_{prx=4,y} = PP\_ProdNDX_{3,y} \tag{266}$$

tissue paper ($prx = 5$):

$$PP\_ProdNDX_{prx=5,y} = \frac{PP\_Proxy\_3_y}{PP\_Proxy\_2_y} \tag{267}$$

where

$PP\_Proxy_{r,y}$ = the value of industrial output in the associated industry, *r*, from the MAM for year *y*, except for PP_Proxy_5, which is read in from the ironstlx.xlsx input file; and

$PP\_ProdNDX_{\ prx,y}$ = production index reflecting change in production shares of each paper type (prx) for year y relative to the base year.

Next, a temporary, un-normalized estimate of paper production shares is calculated as follows:

$$Paper\_Temp_{prx,y} = PP\_ProdNDX_{prx,y} * Paper\_Share_{prx,Base} \qquad (268)$$

where

$Paper\_Share_{prx,Base}$ = the base year shares of total paper production for product prx, based on data from the AFPA.

The normalized shares are subsequently calculated:

$$Paper\_Share_{prx,y} = \frac{Paper\_Temp_{prx}}{\sum_{prx=1}^{5} Paper\_Temp_{prx}} \qquad (269)$$

Mechanical pulping allocation

Mechanical pulping is another step in which greater detail is required. Mechanical pulping refers to two processes: conventional mechanical pulping and thermomechanical pulping. The former is used primarily for such products as newsprint, while the latter is used mainly in the production of tissue. The submodule uses the proxy indices described above to estimate the shares of mechanical pulp attributable to the two processes. The base year share is obtained from AFPA data. The shares of mechanical pulp attributable for the processes are calculated as follows:

$$Mech\_Share_y = Mech\_Share_{y-1} * \left[\frac{Paper\_Share_{1,y} \Big/ \left(Paper\_Share_{1,y} + Paper\_Share_{5,y}\right)}{Paper\_Share_{1,y-1} \Big/ \left(Paper\_Share_{1,y-1} + Paper\_Share_{5,y-1}\right)} \right] \qquad (270)$$

Essentially, this process assumes that the marginal change in mechanical pulping's share is equal to the marginal change in newsprint's share of newsprint and tissue paper.

Note on internal benchmarking

The pulp and paper submodule uses process steps and data from external sources, and we calibrated the results of this submodule to agree with MECS estimates of energy consumption in the paper industry. These efforts have required some minor adjustments to energy intensity figures used in the calculations and changes in the mix of boiler types used to produce steam. The following notes describe the process used in calibrating the submodule's results.

- Net electricity represents only that electricity produced from outside sources. The difference is internally produced and is assumed to be all CHP; some CHP is produced by biofuels (black liquor and hog fuel) and the remainder is produced by conventional fuels (natural gas, heavy fuel oil, , and coal).
- Black liquor and hog fuel production is determined by the submodule and benchmarked to MECS by adjusting coefficients for black liquor production in the Kraft and semi-chemical pulping processes and by inferring the percentage of wood prep waste that is recovered as

hog fuel. The hog fuel (in excess of that demanded by lime kilns) is used to produce steam at a 69% efficiency, which offsets steam demand from other processes and is also used for electricity generation. A similar approach is used with the black liquor recovery furnace, where steam production is determined by technology data.

- The remaining steam demanded by the various processes is produced by conventional fuels in either CHP systems or boilers. Some of the steam is assumed to be recycled, reducing the demand for conventional fuels—the percentage of recycled steam is set to a fixed value, and the mix of boiler types is manually adjusted so that total conventional fuel consumption agrees with MECS figures.

Appendix A. Module Abstract

Module name: Industrial Demand Module

Module acronym: IDM

Description

The Industrial Demand Module is based on economic and engineering relationships that model industrial sector energy consumption at the census division level of detail. The 7 most energy-intensive industries are modeled at the detailed process step level, and 17 other industries are modeled at a less-detailed level. The IDM incorporates three components: buildings; process and assembly; and boiler, steam, and cogeneration.

Purpose of the module

As a component of the National Energy Modeling System integrated modeling tool, the IDM generates long-term projections of industrial sector energy consumption. The IDM facilitates policy analysis of energy markets, technological development, environmental issues, and regulatory development as they affect industrial sector energy consumption.

Most recent module update

December 2024

Part of another model

National Energy Modeling System (NEMS)

Module interfaces

The Industrial Demand Module receives inputs from the Electricity Market Module (EMM), Natural Gas Market Module (NGMM), Hydrocarbon Supply Module (HSM), Renewable Fuels Module (RFM), Macroeconomic Activity Module (MAM), Transportation Demand Module (TDM), Commercial Demand Module (CDM), Liquid Fuels Market Module (LFMM), and Hydrogen Market Module (HMM).

Official model representatives

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Office of Energy Analysis
Office of Long-Term Energy Modeling
Energy Consumption and Efficiency Modeling Team
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Documentation

Model Documentation Report: Industrial Demand Module of the National Energy Modeling System, July 2025.

Archive media and installation manuals

The module is archived as part of the National Energy Modeling System production runs used to generate AEO2025.

Energy system described: domestic industrial sector energy consumption.

Coverage

Geographic: Nine census divisions: New England, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, Mountain, and Pacific.

Time unit and frequency: Annual, 2018 through 2050.

Modeling features

Structure: 18 manufacturing and 6 non-manufacturing industries. The manufacturing industries are further classified as energy-intensive or non-energy-intensive industries.

Each industry is modeled as three separate but interrelated components consisting of the process and assembly component (PA), the buildings component (BLD), and the boiler, steam, and cogeneration component (BSC).

Modeling technique: The energy-intensive industries are modeled using either a detailed process flow with technology diffusion or end-use accounting procedure. The remaining industries use the same general procedure but do not include a detailed process flow.

Non-EIA input sources:

- Consolidated Impact Modeling System (CIMS) technology parameters
- American Forestry and Paper Association's 2021 Statistics, Annual Summary
- American Iron and Steel Institute's 2018 Annual Statistical Report
- U.S. Department of Energy's Industrial Technology Office bandwidth studies
- Life Cycle Assessment Reports (2013 and 2022) from the Aluminum Association
- The U.S. Geological Survey's Minerals Yearbook (multiple years)
- The Portland Cement Association's US Labor and Energy Survey, 2021
- Bloomberg
- American Chemistry Council data
- U.S. Census Bureau's Annual Survey of Manufactures 2022
- Various other scientific and industrial literature on industrial technology and trends (see bibliography)
- U.S. Census Bureau's Economic Census 2017

EIA input sources:

- Form EIA-923 and predecessor forms: Annual Electric Generator Report
- Form EIA-860 and predecessor forms: Annual Electric Generator Report
- Electricity generation, total and by prime mover
  Petroleum Supply Annual 2024
- Manufacturing Energy Consumption Survey 2018, March 2021
- State Energy Data System 2022, June 2024
  Monthly Energy Review, (annual data 2023) December 2024
- Short-Term Energy Outlook, December 2024
  Quarterly Coal Report, April 2024

Appendix B. Data Inputs and Input Variables

Industrial demand module exogenous input files

The Industrial Demand Module (IDM) uses the following input files along with their associated subroutines. The subroutines that read in the files are provided along with the update schedule. The following sections provide more detail on each of the currently used input files. Accompanying this list are the input data that a user can use to run the IDM.

Table B-1. Input files for the Industrial Demand Module

File name	Description	Subroutine where read occurs	Update schedule
carbshrca.csv	Total CO_2 emissions by industry covered by California's AB32 law	Read_carbshrca	Update with MECS
enprod.txt	Production, energy, and byproduct data	IRHEADER, IRBSCBYP, IRSTEPBYP	Update with MECS
ethanereg.csv	Fraction of ethane feedstock consumed in each census division by year, from 1990 to four years after the last STEO year	READ_ETH_FRAC	Annual
exstcap.txt	Cogeneration history data on capacity, generation, and fuel consumption	IRCOGEN	Annual
feedstock.csv	Historical and projected feedstock values for natural gas, naphtha, and hydrocarbon gas liquids from 2006 through the year after the last STEO year	READ_FEEDSTOCK	Annual
ibfactri.csv	Obsolete	IRSTEO	Annual
ind_coal.csv	Industry-level steam coal consumption values based on EIA's *Quarterly Coal Report*	Read_coal	Annual
ind_electric.csv	Industry-level purchased electricity values based on the U.S. Census Bureau's Annual Survey of Manufactures	Read_electric	Paused (see note)
Ind_H2.csv	Base year hydrogen supply and demand by chemical subsector and census region; also includes refining supply of H_2 by census division	Read_H2	Update with MECS
indbeu.txt	Industrial building energy use input	ISEAM	Update with MECS
indcment.txt	Input data for cement, aluminum, and glass submodules, and for coal mining	READ_IDMINPUT	As needed
indcogenx.xlsx	Cogeneration input data	COGENT	As needed
indrun.txt	IDM control file	RCNTL	As needed
ironstlx.xlsx	Input data for process flow submodules	IS_GETDATA	As needed
itech.txt	UECs and TPCs from MECS	UECTPC	Update with MECS
itlbshr.txt	Boiler elasticities and the latest MECS BSC (boiler steam cogeneration) fuel totals	RCNTL	Update with MECS
plancap.txt	Cogeneration planned capacity values	IRCOGEN	Annual
prodflow.txt	Data on production flow rates by process assembly steps, retirement rates, and reporting	MECSBASE	Review with MECS update
propanereg.csv	Fraction of industrial propane feedstock consumed in each census division by year, from 1990 to four years after the last STEO year	READ_PROP_FRAC	Annual
steovars.csv	File containing STEO data used in multiple modules	INDEASY	Annual

Source: U.S. Energy Information Administration

Note: The U.S. Census Bureau transitioned from the Annual Survey of Manufactures to a new survey, the Annual Integrated Economic Survey (AIES). We plan to start using AIES data when they are available.

Buildings data — indbeu.txt

This input file is energy use data for buildings associated with the manufacturing industries, which excludes non-manufacturing industries (indices from 1 to 6). Data include building energy use for lighting, heating, ventilation, and air conditioning as well as on-site transportation. After reading in the data, building energy use is converted from trillion Btu to trillion Btu per million employees.

Table B-2. indbeu.txt inputs

Input data	Description	Units
Inpind	Industry identification index (see Table 2)	Integer
Dumc	Industry label read in as a dummy value that is not used	Character*15
Inpreg	Census region number	Integer
enbint(1,1)	Lighting: electricity	Real: trillion Btu
enbint(2,1:3)	HVAC: electricity, natural gas, steam	
enbint(3,1:2) enbint(3,4:5)	On-site transportation: electricity, natural gas	
enbint(3,4:5)	On-site transportation: distillate, propane	
enbint(4,1:2)	Facility support: electricity, natural gas	
enbint(4,4:5)	Facility support: distillate, propane	

Source: U.S. Energy Information Administration, Residential Demand Module and Commercial Demand Module

Cogeneration data — indcogenx.xlsx

This input file provides data associated with the cogeneration code and is read in the first year. The data are read in from an Excel file (indcogenx.xlsx) as named ranges.

Table B-3. indcogenx.xlsx inputs

Input data	Description	Units
CogSizeKW(nsys)	Electricity capacity for steam systems—*nsys* is the number of systems and is a parameter set to 8	Real: kilowatts
CapCostYearly	Total installed cost—*endyr* is set to 2050	Real: 2022$ per kilowatt
CapFac(nsys)	Capacity factor for the cogeneration system	Real
CHeatRateYearly(2015:endyr,nsys)	Overall heat rate by year	Real: Btu per kilowatthour (HHV)
OverAllEffYearly(2015:endyr,nsys)	Overall efficiency by year	Real
SteamSeg_Food(nload)	Percentage of steam loads by load segment for food – *nload* is the number of load segments and is a parameter set to 8	Real
SteamSeg_Paper(nload)	Percentage of steam loads by load segment for paper	Real

SteamSeg_Chem (nload)	Percentage of steam loads by load segment for chemicals	Real
SteamSeg_Steel(nload)	Percentage of steam loads by load segment for steel	Real
SteamSeg_Other(nload)	Percentage of steam loads by load segment for other manufacturing	Real
SteamSeg_Refin(nload)	Percentage of steam loads by load segment for refining	Real
ThermalCap(nload)	Cogeneration thermal capacity	Real: million Btu per hour
Penetration(nload)	Yearly penetration fraction	Real
AcceptFrac(13)	Fraction of firms willing to accept a payback period of *N* years or longer, for N=0 to 12 years. Applies to smaller plants	Real
AcceptFrac2(13)	Same as AcceptFrac, but applies to larger plants	Real
CapCostMult(nsys)	Capital cost multiplier—used to implement policy options such as an investment tax credit	Real
CapCostMultStart	Starting year in which CapCostMult goes into effect	Integer
CapCostMultEnd	Ending year in which CapCostMult goes out of effect	Integer
StandByFrac	Fraction of CogElecPrice representing standby charges	Real

Source: U.S. Energy Information Administration

The higher heating value (HHV, also known as gross heating value) equals the total heat obtained from combustion of a specified amount of fuel and its stoichiometrically correct amount of air, both being at 60°F when combustion starts and after the combustion products are cooled. HHV assumes the water component is all in a liquid state at the end of combustion.

Energy and production data file — enprod.txt

Three separate sets of data in this file are read in by the following three separate subroutines:

- IRHEADER: Reads industry and region identifier numbers, base year values of output, physical to dollar output conversion factors, and base year steam demand. This input is required.
- IRBSCBYP: Reads byproduct fuel information for the boiler, steam, and cogeneration component. These data consist of fuel identifier numbers and steam intensity values. This input is not required.
- IRSTEPBYP: Reads byproduct data for process and assembly component. These data consist of fuel identifier numbers and heat intensity values. This input is not required. The step name is limited to eight characters because this name is placed in an eight-character matrix for steps in the enprod.txt file. Otherwise, the limit is 24 characters. The step names from the prodflow.txt file are used.

The code that reads in the IRHEADER data calculates the ratio of physical output to the most recent MECS data value of shipments for pulp and paper, glass, cement, steel, and aluminum industries. This constant ratio is applied to value of shipments for subsequent years.

Table B-4. Subroutine IRHEADER, IRBSCBYP, and IRSTEPBYP input data

Input data	Description	Units
Subroutine IRHEADER		
INDDIR	Industry identification number (see Table 2)	Integer
IDVAL	Value indicating industrial output units of physical (1) or dollar value (2)	Integer
BASE_SHIP	Industrial output in the base module year	Real
Dum	Reads in a dummy value that is not currently used	Real
STEMCUR	Steam demand from process and assembly and buildings	Real
Subroutine IRBSCBYP		
Idum	Step number	Integer
Ifx	The ID number for the byproduct fuel that is stored in IFSLOCBY(6) after being read in. The intermediate products and renewables from which the ID number is selected are listed below in Tables B-5 and B-6.	Integer
(temp(J),J=1,2)	After being read in, the data are stored in: BYSINT(IFSBYP) = temp(1) — boiler efficiency for byproduct fuel. Currently always 1.4. BYBSCSC(IFSBYP) = temp(2) — conservation supply coefficient for byproduct fuel j. Values are all set to zero, so not used.	Real
Subroutine IRSTEPBYP		
Idum	Step number	Integer
Ifx	The index for the byproduct fuel by process step that is stored in IFLOCBY(10,maxstep) after being read in. The intermediate products and renewables from which the index is selected are listed below.	Integer
Temp(J),J=1,4	After being read in, the data are stored in: BYPINT(3,5,maxstep) is vintaged byproduct unit energy consumption by region and process, with TEMP(1) going to vintage 1 and TEMP(3) to vintage 2 and 3. BYPCSC(3,5,maxstep) is vintaged byproduct efficiency coefficients by region and process. It uses TEMP(2) for vintage 1 and TEMP(4) for vintages 2 and 3, though those values are currently all zero.	Real

Source: U.S. Energy Information Administration

Table B-5. The intermediate products quantity array QTYINTR(6,5)

Fuel index in QTYINTR	Fuel
1	steam
2	coke oven gas
3	blast furnace gas
4	other byproduct gas
5	waste heat

6	coke

Note: The variable IFSLOC has an alternate fuel index for these fuels, equal to the above indices plus 30.

Source: U.S. Energy Information Administration

Table B-6. The renewables quantity array: QTYRENW(8,5)

Fuel index in QTYRENW	Fuel
1	hydropower
2	biomass—wood
3	biomass—pulping liquor
4	geothermal
5	solar
6	photovoltaic
7	wind
8	municipal solid waste

Note: The variable IFSLOC has an alternate fuel index for these fuels, equal to the above indices plus 40.

Source: U.S. Energy Information Administration

In addition, the QTYMAIN(24,5) array is the consumption of main fuels in census regions. The array QtyByInd is the sum of QTYMAIN and QTYRENW into 24 reporting real categories by industry.

IDM control file — indrun.txt

These values generally do not change. Unless otherwise indicated, the value used in the table is the default value.

Table B-7. indrun.txt input variables

Input data	Description
ISUBTR	Obsolete printout option.
INDMAX	The total number of industries in this run. Set to 21.
IWDBG	Should the debug file indtst.txt be written (0=no, 1=yes)? Set to 0.
ISEDS	Benchmark to SEDS (0=no, 1=yes)? Set to 1.
ICALIBRATE	Benchmark individual industry table to Table 6. U.S. total (0=no, 1=yes)? Set to 1.
IPRICE	Should price sensitivities be done (0=no, 1=yes). Set to 0.
ELEC	Price sensitivity factor for electricity. Set to 1.
FGAS	Price sensitivity factor for firm natural gas. Set to 1.
INTGAS	Enter price sensitivity factor for interruptible gas. Set to 1.
COAL	Enter price sensitivity factor for coal. Set to 1.
RESID	Enter price sensitivity factor for residual oil. Set to 1.
DIST	Enter price sensitivity factor for distillate oil. Set to 1.
LPG	Enter price sensitivity factor for propane. Set to 1.
ITPC	Should TPC sensitivities be done (0=no, 1=yes)? Set to 0.
TPC1	Enter TPC sensitivity factor for old plants (1.0=default).
TPC2	Enter TPC sensitivity factor for new plants (1.0=default).

Input data	Description
FRZTECH	Frozen technology case (0=off, 1=on). Set to 0.
HITECH	High technology case (0=off, 1=on). Set to 0.
EETECH	Energy efficiency case (0=off, 1=on). Set to 0.
IRETIRE	Should retirement rate model sensitivities be done (0=no, 1=yes)? Set to 0.
RETRATE	Retirement rate sensitivity factor (1.0=default).
LOOKAHEAD	Number of lookahead years for CHP (0=default). Set to 5.
carbshr(j)	Share of each industry's fossil consumption subject to carbon allowance costs. Currently all industry values are set to 1.0.

Source: U.S. Energy Information Administration

Boiler elasticities – itlbshr.txt

This file contains boiler elasticities and the latest MECS boiler, steam, and cogeneration (BSC) fuel totals. Three separate datasets are in the file.

Table B-8. itlbshr.txt input variables

Input data	Description	Units
Parameters for logit boiler shares based on MECS		
INDINT	Industry code	Integer
INDRG	Region code	Integer
COEFF(1)	Parameters for logit boiler shares. Currently set to -2 for all industries and regions. Logit coefficients are stored in array TLBSHR(INDINT,INDRG,1).	Integer
Boiler fuels from MECS		
j	The value for INDINT is set in code and read in as a dummy value from 7 to 24. The non-manufacturing industries (1–6) are not included in the data.	Integer
j	The value for INDRG is set in code and read in as dummy value.	Integer
Temp(k),k=1,9	Latest MECS boiler, steam, and cogeneration fuel in trillion Btu in the following order: residual fuel oil, distillate, natural gas, propane, coal, wood or biomass, other petroleum, petcoke, and electricity. Data are stored in array BSCIBYR(INDINT,INDRG,k) with the fuel indices (INDINT) of:	Real: trillion British thermal units
	(1) coal	
	(2) oil—includes sum of resid, distillate, propane, other petroleum, and petcoke	
	(3) natural gas	
	(4) wood or biomass	
	(5) other cogeneration; set to zero since no data	
	(6) MSW cogeneration; set to zero since no data	
	(7) resid	
	(8) distillate	

Input data	Description	Units
	(9) propane	
	(10) other petroleum	
	(11) petcoke	
	(12) electricity	
Size shares		
Indsize	Value is set in code from 1 to 6 corresponding to aggregated industries and some non-aggregated industries: non-manufacturing, food, paper, chemicals, metals, and other manufacturing.	Integer
Ifuel	Value is set in code from 1 to 5 corresponding to natural gas, coal, oil products, biomass, and electricity.	Integer
Sizeshrtemp(indsize,ifuel,1)	There are 24 input lines for the 6 industries and 4 fuels associated with each industry. Size share array by industry, fuel, and size group. There are two size groups with the two values summing to 1.0. The first column value is read to size group 1 (<= 10 MMBtu/hour), and the second column value is read to size group 2 (>10 MMBtu/hour). Values are stored in sizeshr(inddir, jfuel, isize). Adjustments are made in code to apply the aggregated industries and fuel data to all of industries (24) and fuels (12) in the array sizeshr.	Integer

Source: U.S. Energy Information Administration

Production flows — prodflow.txt

The file has three sections for each industry: step definitions, retirement rates, and prodflow rates for each step. Reporting groups are also read in for some industries with process steps.

The MECSBASE subroutine imports production throughput coefficients, process step retirement rates, and other process step flow information from the file prodflow.txt. Imported process step flow data for each process step include process step number, number of links, the process steps linked to the current step, physical throughput to each process step, retirement rate, and process step name.

Data lines starting with an asterisk (*) are not read in. Reporting groups modify the output to the reports indusa.csv, indreg1.csv, indreg2.csv, indreg3.csv, and indreg4.csv.

Table B-9. prodflow steps and reporting groups

Input data	Description	Units
Number of steps and reporting groups		
Inpind	Industry code	Integer
Inpreg	Region	Integer
Nsteps	Number of process steps	Integer
Ngrps	Number of reporting groups, typically set to 0; when set to another value, an additional input is defining the reporting groups	Integer

Input data	Description	Units
Step definitions		
Inpind	Industry code	Integer
Inpreg	Region	Integer
Inpstp	Process step	Integer
Duma	Dummy data and comment; not used	Character*20
Dumc	Dummy data and comment; not used	Character*15
ntmax(inpstp)	Maximum number of links for the process step	Integer
IPASTP(inpstp,IDOWN)	Stores 0 or 1 values indicating process links. The values read are the process steps with links. These values are transformed when read in to 0 or 1 values stored in the array IPASTP.	Integer
Reporting group definitions (only included for an industry if *ngrps* is greater than 0)		
Inpind	Industry code	Integer
Inpreg	Region	Integer
Inpg	Reporting group; go from 1 to *ngrps*	Integer
RptGrpNames(inpg)	Name of the reporting group	Character*24
NumRptGrpSteps(inpg)	Number of steps in the reporting group	Integer
RptGrpSteps(NumRptGrps + 1,is)	Process steps for the reporting group	Integer
RptGrpNames(NumRptGrps+1,is)	Reporting group step labels	Character*24
Retirement rates		
Inpind	Industry code	Integer
Inpreg	Region	Integer
Inpstp	Process step	Integer
Indstepname(inpstp)	Step name	Character*24
Dumc	Dummy comment that is not used	Character*15
PRODRETR(inpstp)	Retirement rate by process step	Real
Production flow rates		
Inpind	Industry code	Integer
Inpreg	Region	Integer
Ivint	Vintage that is read in with the production flow data only; only vintage 1 (old) and 3 (mid) data are provided	Integer
Inpstp	Process step	Integer
Dumc	Dummy comment that is not used	Character*15
prodflow(min(ivint,2),inpstp, idown)	Dimension 2 for production volume to be read in for the old and middle vintage. Vintage 1 is placed in index 1, and vintage 3 is placed in index 2. The production flow is then read in for each step and link.	Real

Source: U.S. Energy Information Administration

Existing and planned cogeneration capacity — exstcap.txt and plancap.txt

The following describes the units in the input file. These values are then stored with unit conversions as shown in Table B-10.

- capacity (cogcap): Total summer capacity in kW. Note however that the reported capacity for each generator is only associated with its primary fuel, so any additional fuels assigned to the generator will have a corresponding capacity of zero. For example, if a generator primarily uses steam from coal but also burns some natural gas or petroleum liquids in the boiler associated with the generator, this factor will be reflected with positive generation being added to both the coal and natural gas or petroleum liquids aggregates. Yet only the coal will reflect a positive addition to its capacity aggregates. This fact will cause a slight skew in the variable capacity factor.
- generation (coggen): annual generation in kWh
- elec fuel use (cogelf): total annual consumption in MMBtu
- thermal (cogthr): useful thermal output in MMBtu
- cap fact (read in, but not stored): total annual generation kWh / (capacity(kW) * hours in a year)
- incr. heatrt: incremental heat rate, defined as (total annual consumption in MMBtu/total annual generation in kWh)*1,000,000, which ultimately brings the units to Btu/kWh. Read in, but not stored.
- grid share (coggrd): industry- and census-weighted average of (total_generation-facility_use)/total_generation (kWh). Note that this share is not fuel-specific, so all fuels in each industry or census group will have the same grid share value.

Table B-10. exstcap.txt and plancap.txt input data

Input data	Description	Units (read in)
iyear	Year	Integer
adum	Dummy input	Character*25
ind	Industry	Integer
ir	Census division	Integer
adum	Dummy input	Character*25
ifuel	Fuel index	Integer
cogcap(ir,iyear,ind,ifuel)/1000	Capacity	Real: kilowatts
coggen(ir,iyear,ind,ifuel)/1000000	Generation	Real: kilowatthours
cogelf(ir,iyear,ind,ifuel)/1000000	Electricity fuel use	Real: million British thermal units
cogthr(ir,iyear,ind,ifuel)/1000000	Useful thermal output	Real: million British thermal units
Read in, but not stored	Capacity factor	Real
Read in, but not stored	Incremental heat rate	Real: British thermal units per kilowatthour
coggrd(ir,iyear,ind,ifuel)/1000000	Grid share	Real

Source: U.S. Energy Information Administration

The data source for plancap.txt is also the Form EIA-860 survey. We manually edit this file by removing the planned builds labeled Oil n Gas Extrk because CHP used in oil and natural gas extraction is covered under another NEMS module. We also remove any entries for coal-fueled CHP in the non-manufacturing industries (agriculture, construction, and mining) because coal consumption in those industries is so minor it is not included in SEDS. The data that are read in have the same format as for exstcap.txt except is stored in the array cogadd.

Process and assembly step input (end-use industries only): itech.txt

The itech.txt file contains unit energy consumption for the end-use industries to be used for energy consumption in process and assembly.

Table B-11. itech.txt inputs for unit energy consumptions (UECs) and technology possibility curves (TPCs)

Input data	Description
i_ind	Industry number
i_ir	Region number
i_stp	Step number
Duma	Dummy input
i_ifx	Fuel code
Duma	Dummy input
einter(1,i_ifx,i_stp)	UEC base year, original vintage
minpint(1,i_ifx,i_stp)	UEC 2050, original vintage
bcsc(1,i_ifx,i_stp)	TPC, original vintage
einter(3,i_ifx,i_stp)	UEC base year, new vintage
minpint(3,i_ifx,i_stp)	UEC 2050, new vintage
Bcsc(3,i_ifx,i_stp)	TPC, new vintage

Source: U.S. Energy Information Administration

Cost, performance, and physical input data for five process flow industries in ironstlx.xlsx

The first table has variables that are related to input data from ironstlx.xlsx for process flow submodules: cement and lime, aluminum, glass, iron and steel, and paper. Each industry is on its own labeled tab in the spreadsheet. Each tab in the input file has ranges that are defined and read into the listed variables from the subroutine IS_GETDATA. Many of the same array variables are used in the process flow industries. The following five tables list inputs for each industry.

Table B-12. Steel input data in ironstlx.xlsx

Input data	**Description**	**Type**
B_SHR	Initial and final shares of conventional boilers	Real
B_T_Final(n_boil_tech)	Final shares of each boiler technology and final year	Real
B_T_Start(n_boil_tech)	Initial shares of each boiler technology and initial year	Real
B_T_YEAR(2)	Years for B_T_START and B_T_FINAL	Real
B_YEAR(2)	Initial and final years to calculate shares of conventional boilers	Real
BASE_BOF(inumreg)	Regional base year values for BOF PRODFLOW element	Real
BASE_Coke(inumreg)	Regional base year values for coke PRODFLOW element	Real
BASE_Cold(inumreg)	Regional base year values for cold-rolled PRODFLOW element	Real
BASE_EAF(inumreg)	Regional base year values for EAF PRODFLOW element	Real
BILLBAR(4)	Hot roll energy intensity of bar billets by fuel (natural gas, heavy fuel oil, and electricity), in MMBtu/thousand metric tons shipments; and, CO_2 intensity in metric ton CO_2/thousand metric tons shipments	Real

BILLROD(4)	Hot roll energy intensity of rod billets by fuel (natural gas, heavy fuel oil, and electricity), in MMBtu/thousand metric tons shipments; and, CO_2 intensity in metric tons CO_2/thousand metric tons shipments	Real
BILLSHAPE(4)	Hot roll energy intensity of light structural shape billets by fuel (natural gas, heavy fuel oil, and electricity), in MMBtu/thousand metric tons shipments; and, CO_2 intensity in metric tons CO_2/thousand metric tons shipments	Real
BLOOMSTRUCT(4)	Hot roll energy intensity of heavy structural shape blooms by fuel (natural gas, heavy fuel oil, and electricity), in MMBtu/thousand metric tons shipments; and, CO_2 intensity in metric tons CO_2/thousand metric tons shipments	Real
BLOOMTUBES(4)	Hot roll energy intensity of tube blooms by fuel (natural gas, heavy fuel oil, and electricity), in MMBtu/thousand metric tons shipments; and, CO_2 intensity in metric tons CO_2/thousand metric tons shipments	Real
BOIL_INTENSITY(5,n_boil_tech)	Fuel and CO_2 intensity factors for conventional boilers, in MMBtu/GJ steam and metric tons/GJ steam, respectively	Real
C_T_FINAL(n_chp_tech)	Shares of each CHP technology in the final model year	Real
C_T_START(n_chp_tech)	Shares of each CHP technology in the initial model year	Real
C_T_YEAR(2)	Initial and final model years for C_T_START and C_T_FINAL	Real
CC_NGAS(4)	Continuous casting fuel intensities in MMBtu fuel/thousand metric tons shipments and emissions in metric tons CO_2/thousand metric tons shipments	Real
CHP_INTENSITY(5,n_chp_tech)	Fuel and CO_2 intensity factors for CHP systems, in MMBtu/GJ steam and metric tons/GJ steam, respectively	Real
CO2_INTENSITY(6,2)	Emissions of CO_2, by sub-process (metric ton CO_2/thousand metric tons of production)	Real
DRI_TOT_PHASE1(inumreg)	Initial DRI capacity in IDM base year, by census region	Real
DRI_TOT_PHASE2(inumreg)	Total production of DRI in phase 2 year, representing any exogenously added DRI capacity	Real
DRI_TOT_PHASE3(inumreg)	Total production of DRI in phase 3 year, representing any exogenously added DRI capacity	Real
FORMSHARES(3)	Hot roll shares for blooms, billets, and slabs	Real
HFO_SHARE	Share of cold-rolled steel production using heavy fuel oil technologies (percentage)	Real
Intensity(6,3)	Energy intensity by sub-process and fuel (natural gas, electricity, and heavy fuel oil) in MMBtu/thousand metric tons	Real
IS_ADD_TECH_SHARE(inumind, maxstep,maxtech)	Share for each added technology for IS 1, 3 to 7	Real
IS_ALPHA(inumind,maxstep, maxtech)	Alternative-specific constant for IS 1, 3 to 7	Real
IS_ALPHA_DECAY(inumind,2)	Alpha decay parameters that reduces alternative specific constants	Real
IS_ALPHA_FURNACE(inumreg)	Sensitivity parameter for EAF/BOF switching	Real
IS_AV_OM(inumind,maxstep, maxtech)	Technology operations and maintenance cost (dollars per thousand metric tons of steel capacity) for IS 1, 3 to 7	Real
IS_BASE_TECH_SHARE(inumind, maxstep,maxtech)	Share for each baseline technology for IS 1, 3 to 7	Real
IS_BASELIFECR(inumind)	Lifetime of baseline capacity (years)	Integer
is_BldCHPShr	Building CHP share	Real
IS_CALIB(inumind)	Technology survival curve calibration constant (user-specified)	Integer
IS_CAPCOST(inumind,maxstep, maxtech)	Technology capital cost (dollars per thousand metric tons steel capacity) for IS 1, 3 to 7	Real
IS_CapFacAvg(3)	Cogeneration capacity factor weighted average	Real

IS_CENERGY_USE(7)	Coke energy use (MMBtu/thousand metric tons steel) adjusted after read in with IS_STEAM_ADJ	Real
IS_CO2PENALTY(inumind,icuriyr:61)	CO_2 penalty starting with 2018 and to the end of the projection period; applied to all process flow industries	Real
IS_CPROCESS(4)	Coke process output factors; breeze, coke oven gas, tars, light oils	Real
IS_EMISS(inumind,maxstep,maxtech)	Technology-level CO_2 emissions (metric tons CO_2/thousand metric tons steel) for IS 1, 3 to 7	Real
IS_FISYR(inumind)	First calculated year	Integer
IS_FUEL_USE(inumind,maxstep, IS_MAXFUEL,maxtech)	Fuel intensity: 1=electricity, 2=natural gas, 3=heavy fuel oil, 4=coal, and 5=hydrogen (MMBtu/thousand metric tons shipments) for 1, 3 to 7	Real
IS_LIFETIME(inumind)	Lifetime of added capacity (years)	Real
IS_LOGIT_COEFF(inumind,3,maxstep)	Logit coefficients for (1) fixed cost, (2) fuel cost, and (3) CO_2 emissions	Real
IS_NFUEL_USE(inumind,maxstep,2, maxtech)	Non-fuel intensity: 1=oxygen (metric tons O_2/thousand metric tons shipments) and 2=steam (GJ/thousand metric tons shipments) for 1, 3 to 7. Adjusted after read in with IS_STEAM_ADJ	Real
IS_NUMFUEL(inumind,maxstep)	Number of fuels in each step	Integer
IS_NUMTECH(inumind,maxstep)	Number of technologies in each step	Integer
IS_PRODUCTION(inumind,maxstep)	Historical step production (thousand metric tons); also known as PRODCUR	Real
IS_REI(inumind,maxstep,maxtech)	Relative energy intensity for state-of-the-art technology	Real
IS_STEAM_ADJ	CIMS steam adjustment factor	Real
IS_WACC(inumind)	Weighted average cost of capital (WACC)	Real
ISCR_SHARES(2:6)	Shares of cold-rolled steel by sub process	Real
MECS_DATA(inumind,5,10)	MECS benchmark factors for electricity, natural gas, residual fuel, steam coal, distillate, propane heat and power, petcoke, renewables, met coal, and other petroleum	Real
NG_SHARE	Share of cold-rolled steel production using natural gas technologies	Real
OBSOLETEYR(inumind,maxstep, maxtech)	Technology obsolescence year for IS 1, 3 to 7	Real
PHASE1_YR(inumreg)	IDM base year for exogenous DRI capacity additions	Integer
PHASE2_YR(inumreg)	First year of exogenous DRI capacity addition (2020 in AEO2025, representing a DRI addition at a Clevland Cliffs facility)	Integer
PHASE3_YR(inumreg)	Second year of exogenous DRI capacity addition (placeholder)	Integer
SHRFINAL(12)	Hot roll ending shares and year (index 1) to project future shares	Real
SHRSTART(12)	Hot roll starting shares and year (index 1) to project future shares	Real
SLABSKIN(2)	Hot roll electricity use for the slab product skin pass and pickling technologies, in MMBtu/thousand metric tons steel	Real
SLABTECH1(2)	Hot roll electricity use for the slab product technology 1 for roughing and finishing technologies	Real
SLABTECH2(2)	Hot roll electricity use for the slab product technology 2 for roughing and finishing technologies	Real

Source: U.S. Energy Information Administration

Table B-13. Paper input data in ironstlx.xlsx

Input data	Description	Type
BldCHPShr	Building CHP share	Real
CapFacAvg(2,4)	Capacity factor weighted average	Real
HOG_HEAT	Hog fuel net heat content	Real
HOG_PULP	Metric tons wood/metric tons pulp	Real
HOG_WASTE	Percentage of waste to hog fuel	Real
IBYR_SURVCAP(inumind,maxstep)	Base year surviving capacity	Real

Input data	Description	Type
IS_ADD_TECH_SHARE(inumind,maxstep, maxtech)	Initial added share for each technology	Real
IS_ALPHA(inumind,maxstep,maxtech)	Alternative-specific constant	Real
IS_ALPHA_DECAY(inumind,2)	Alpha decay factor (reduces alternative-specific constants)	Real
IS_AV_OM(inumind,maxstep,maxtech)	Technology operations and maintenance cost (dollars per thousand metric tons of paper capacity)	Real
IS_BASE_TECH_SHARE(inumind,maxstep, maxtech)	Share for each baseline technology	Real
IS_BASELIFECR(inumind)	Lifetime of baseline capacity (years)	Integer
IS_CALIB(inumind)	Technology survival curve calibration constant (user-specified)	Integer
IS_CAPCOST(inumind,maxstep,maxtech)	Technology capital cost (dollars per thousand metric tons of paper capacity)	Real
IS_EMISS(inumind,maxstep,maxtech)	Technology CO_2 emissions (metric tons CO_2/thousand metric tons paper)	Real
IS_FISYR(inumind)	First calculated year	Integer
IS_FUEL_USE(inumind,maxstep, is_maxfuel,maxtech)	Fuel intensity for 1=electricity, 2=natural gas, 3= heavy fuel oil, 4=steam coal, and 5=met coal in MMBtu/thousand metric tons shipments	Real
IS_LIFETIME(inumind)	Lifetime of added capacity (years)	Real
IS_LOGIT_COEFF(inumind,6,maxstep)	Logit coefficients for (1) fixed cost, (2) fuel cost, and (3) CO_2 emissions	Real
IS_NFUEL_USE(inumind,maxstep,2, maxtech)	Non-fuel intensity for 1=black liquor (metric tons black liquor/thousand metric tons shipments) and 2=steam (GJ/thousand metric tons shipments)	Real
IS_NUMFUEL(inumind,maxstep)	Number of fuels in each step	Integer
IS_NUMTECH(inumind,maxstep)	Number of technologies in each step	Integer
IS_PRODUCTION(inumind,maxstep)	Historical step production (thousand metric tons); also known as PRODCUR	Real
IS_REI(inumind,maxstep,maxtech)	Relative energy intensity for state-of-the-art technology	Real
IS_WACC(inumind)	Weighted average cost of capital (WACC)	Real
MECH_SHARE(17:31)	Allocation shares between mechanical and thermo-mechanical pulping technologies	Real
MECS_DATA(inumind,5,10)	MECS benchmark factors for electricity, natural gas, residual fuel, steam coal, distillate, propane heat and power, petcoke, renewables, met coal, and other petroleum	Real
OBSOLETEYR(inumind,maxstep, maxtech)	Technology obsolescence year	Real
PAPER_SHARE(5,17:31)	Allocation shares for paper production (five paper types)	Real
PP_BIOBOILEFF	Boiler efficiency (biomass)	Real
PP_BLKLIQ(maxstep,maxtech)	Paper black liquor production (metric tons black liquor/thousand metric tons shipments), with negative values representing production	Real
PP_CHIP	Electric fuel use for wood preparation chipping (MMBtu/thousand metric tons shipments)	Real
PP_HFOSHR(4)	Share out heavy fuel oil: residual fuel, petcoke, distillate, and other petroleum	Real
PP_HOG(maxstep,maxtech)	Paper hog fuel consumption (GJ hog fuel/thousand metric tons shipments)	Real
PP_ProxyDat(17:61)	Data from the MAM that will be directly passed to the IDM (2006–2050, though the data don't get used prior to the base year)	Real
PP_STEAM(maxstep,maxtech)	Technology steam demand (GJ steam/thousand metric tons shipments), with negative values representing produced steam	Real
PP_STM_RYCL	Percentage steam that is recycled (pulp and paper)	Real
PP_STMFUEL_BL(4,5)	Boiler fuel use for paper steam (GJ fuel/GJ steam) and boiler CO_2 emissions (metric tons CO_2/GJ steam)	Real

Input data	Description	Type
PP_STMFUEL_CHP(9,5)	CHP fuel use for paper steam (GJ fuel/GJ steam) and CHP CO_2 emissions (metric tons CO_2/GJ steam)	Real
PPST_SHRFINAL(17,2)	Final shares (second index=1) and year (second index=2) for paper steam	Real
PPST_SHRSTART(17,2)	Starting shares (second index=1) and year (second index=2) for paper steam	Real

Source: U.S. Energy Information Administration

Table B-14. Cement and lime input variables in ironstlx.xlsx

Input data	Description	Type
C_MASS_LOSS	Amount of kiln output in the wet cement process (in metric tons) needed to produce one metric ton of grinding output	Real
CM_ADD	Fraction of finish grinding metric tons composed of other additives	Real
CM_ALPHA_DECAY(maxstep,4,2)	Alpha decay factor (reduces alternative-specific constants)	Real
CM_BASELIFECR(4)	Lifetime of baseline capacity by process step (years)	Integer
CM_BASELIFEDRY	Years until total retirement of existing stock of dry process capacity	Real
CM_BASELIFEWET2(4)	Years until total retirement of existing stock of wet process capacity for different scenarios (index 1=Reference case, 2=high technology case, 3=frozen technology, 4=energy efficient case)	Real
CM_CALIB(4)	Technology survival curve calibration constant (user-specified)	Integer
CM_CAPSHR(2)	Shares of baseline kiln capacity accommodated by wet (index=1) and dry (index=2) process kilns	Real
CM_COMBCO2(maxstep,maxtech)	Combustion CO_2 emissions from cement kiln burners, in metric tons CO_2/GJ of heat service	Real
CM_ELECCOEF(6)	Coefficient used to calculate cement kiln electricity consumed based on clinker output and kiln technology; electricity use increases as coefficient value increases	Real
CM_FISYR(4)	First calculated year	Integer
CM_FUELMIX(7,5)	Array defining which fuels (second index) are used by each burner technology (first index, with 1=natural gas, 2=residual fuel oil, 3= steam coal, 4= petcoke, 5=multi-channel burner); 1 indicates the fuel is used by the technology, while 0 indicates the fuel is not used	Real
CM_HEATCOEF(6)	Coefficient used to calculate heat requirement based on clinker production and kiln technology; heat requirement increases when coefficient value increased	Real
CM_HEATDCOEF	GJ of heat service needed per metric ton of clinker produced	Real
CM_HEATSRV(maxtech)	Cement kiln heat service needed, in GJ of heat/thousand metric tons of kiln throughput	Real
CM_HEATSRV_FUEL(maxtech)	Heat service fuel use in cement kiln burners by technology, in MMBtu fuel/thousand metric tons of kiln throughput	Real
CM_IMPORT_CLINK	Fraction of finish grinding metric tons composed of imported clinker	Real
CM_LIFETIME(4)	Lifetime of added capacity by process step (years)	Real

Input data	Description	Type
CM_RAWTECH(2)	Raw grinding wet production technology split	Real
CM_WACC(4)	Weighted average cost of capital (WACC)	Real
CM_WETCOEF(maxtech)	Burner allocation by technology in the wet process	Real
CM_WETCOEF2(maxtech)	Wet grinding process energy extra electricity consumption by technology (MMBtu per thousand metric tons throughput)	Real
IBYR_SURVCAP(inumind,maxstep)	Base year surviving capacity	Real
IS_ADD_TECH_SHARE(inumind,maxstep, maxtech)	Initial added share for each technology	Real
IS_ALPHA(inumind,maxstep,maxtech)	Alternative-specific constant	Real
IS_AV_OM(inumind,maxstep,maxtech)	Technology operations and maintenance cost (dollars per thousand metric tons of throughput capacity)	Real
IS_BASE_TECH_SHARE(inumind, maxstep, maxtech)	Share for each baseline technology	Real
IS_CAPCOST(inumind,maxstep,maxtech)	Technology capital cost (dollars per thousand metric tons of throughput capacity)	Real
IS_ECALIB(inumind,maxstep)	Electricity calibration constant for each cement process steps	Real
IS_EMISS(inumind,maxstep,maxtech)	Technology CO_2 emissions (metric tons CO_2/thousand metric tons shipments)	Real
IS_FUEL_USE(inumind,maxstep, is_maxfuel,maxtech)	Fuel intensity for 1=electricity, 2=natural gas, 3= heavy fuel oil, 4=steam coal, and 5=met coal in MMBtu/thousand metric tons shipments	Real
IS_LOGIT_COEFF(inumind,6,maxstep)	Cement logit coefficients for (1) fixed cost, (2) electricity fuel cost, (3) particulate emissions, (4) CO_2 emissions, (5) heat service, and (6) natural gas fuel cost; lime logit coefficients for (1) fixed cost, (2) fuel cost, and (3) CO_2 emissions	Real
IS_NUMFUEL(inumind,maxstep)	Number of fuels in each step	Integer
IS_NUMTECH(inumind,maxstep)	Number of technologies in each step	Integer
IS_PRODUCTION(inumind,maxstep)	Historical step production (thousand metric tons); also known as PRODCUR	Real
IS_REI(inumind,maxstep,maxtech)	Relative energy intensity for state-of-the-art technology	Real
MECS_Data(inumind,5,10)	MECS benchmark factors for electricity, natural gas, residual fuel, steam coal, distillate, propane heat and power, petcoke, renewables, met coal, and other petroleum	Real
OBSOLETEYR(inumind,maxstep,maxtech)	Technology obsolescence year	Real

Source: U.S. Energy Information Administration

Table B-15. Aluminum input variables ironstlx.xlsx

Input data	Description	Type
AL_ALPHA_DECAY(maxstep,4,2)	Alpha decay factor (reduces alternative-specific constants)	Real
AL_MASS_LOSS	Mass loss converting alumina to aluminum (fraction)	Real
AL_NON_MET	Non-metallic use of alumina (fraction)	Real

Input data	Description	Type
AL_PF_FUEL(2)	Trillion Btu fuel (1=electricity and 2=natural gas) per thousand metric tons throughput used for product formation	Real
ALUMINA_PERCENT(21:mnumyr)	Alumina imports in a given year (percentage of domestic use)	Real
AnodeRatio(6)	Metric tons of anode per metric ton of aluminum produced, by smelting technology	Real
IBYR_SURVCAP(inumind,maxstep)	Base year surviving capacity for a given process step	Real
IS_ADD_TECH_SHARE(inumind,maxstep, maxtech)	Initial added share for each technology	Real
IS_ALPHA(inumind,maxstep,maxtech)	Alternative-specific constant	Real
IS_AV_OM(inumind,maxstep,maxtech)	Technology operations and maintenance cost (dollars per thousand metric tons of throughput capacity)	Real
IS_BASE_TECH_SHARE(inumind,maxstep, maxtech)	Capacity share for each baseline technology	Real
IS_BASELIFECR(inumund)	Lifetime of baseline capacity (years)	Integer
IS_CALIB(inumind)	Technology survival curve calibration constant (user-specified)	Integer
IS_CAPCOST(inumind,maxstep,maxtech)	Technology capital cost (dollars per thousand metric tons of throughput capacity)	Real
IS_ECALIB(inumind,maxstep)	Electricity calibration constant for each cement process step	Real
IS_EMISS(inumind,maxstep,maxtech)	Technology CO_2 emissions (metric tons CO_2/thousand metric tons throughput)	Real
IS_FISYR	First calculated year	Integer
IS_FUEL_USE(inumind,maxstep, is_maxfuel,maxtech)	Fuel intensity for 1=electricity, 2=natural gas, 3= heavy fuel oil, and 6=petcoke in MMBtu/thousand metric tons throughput	Real
IS_LIFETIME(inumind)	Lifetime of added capacity (years)	Real
IS_LOGIT_COEFF(inumind,6,maxstep)	Logit coefficients for (1) fixed costs, (2) fuel costs except for natural gas, (3) CO_2 emissions, (4) natural gas fuel costs, (5) steam costs	Real
IS_NFUEL_USE(inumind,maxstep, 2,maxtech)	Non-fuel intensity for 1=oxygen (metric tons/thousand metric tons aluminum) and 2=steam (MMBtu/thousand metric tons aluminum)	Real
IS_NUMFUEL(inumind,maxstep)	Number of fuels in each step	Integer
IS_NUMTECH(inumind,maxstep)	Number of technologies in each step	Integer
IS_PRODUCTION(inumind,maxstep)	Historical step production (thousand metric tons); also known as PRODCUR	Real
IS_REI(inumind,maxstep,maxtech)	Relative energy intensity for state-of-the-art technology	Real
IS_WACC(inumind)	Weighted average cost of capital (WACC)	Real
MECS_Data(inumind,5,10)	MECS benchmark factors for electricity, natural gas, residual fuel, steam coal, distillate, propane heat and power, petcoke, renewables, met coal, and other petroleum	Real
OBSOLETEYR(inumind,maxstep,maxtech)	Technology obsolescence year	Real

Source: U.S. Energy Information Administration

Table B-16. Glass input variables ironstlx.xlsx

Input data	Description	Type
CULLET_RECYCLE_SHARE_FINAL(3)	Percent of cullet that is recycled in the final model year by glass type (1=flat, 2= container, 3=blown/specialty)	Real
CULLET_RECYCLE_SHARE_START(3)	Percent of cullet that is recycled in the base year by glass type (1=flat, 2= container, 3=blown/specialty)	Real
GL_ALPHA_DECAY(maxstep,4,2)	Alpha decay factors (reduce alternative specific constants) by process step (first index) and scenario (second index, where 1=Reference case, 2=high technology case, 3=frozen technology case, and 4=energy efficient case) for alpha parameters 1 and 2 (third index).	Real
GL_CRYO	Energy required to produce O_2 for use with oxy-fuel burners (MMBtu electricity/short ton O_2).	Real
GL_MECS(2)	Obsolete	
GL_OXY(3,4)	Oxygen effects on fuel consumption. When the first index is 1, the variable represents the reduction (fraction) of natural gas fuel consumption when oxygen is added to the process, for each type of glass (represented by the second index, where 1=flat, 2=container, 3=blown/specialty, and 4=fiber). When the first index is 2, the variable represents oxygen requirements for typical glass-producing plants in metric tons O_2/metric ton glass for each type of glass (second index). When the first index is 3, the variable represents parameters for a logistic penetration curve for share of oxy-fuel systems by furnace type, with the second index denoting the logistic curve parameters (1=base, 2=max, 3=trigger, and 4=k). These logistic curve parameters were not used in AEO2025.	Real
IS_ADD_TECH_SHARE(inumind,maxstep, maxtech)	Initial added share for each technology	Real
IS_ALPHA(inumind,maxstep,maxtech)	Alternative-specific constant	Real
IS_AV_OM(inumind,maxstep,maxtech)	Technology operations and maintenance cost (dollars per thousand metric tons of throughput capacity)	Real
IS_BASE_TECH_SHARE(inumind,maxstep, maxtech)	Share for each baseline technology	Real
IS_BASELIFECR(inumund)	Lifetime of baseline capacity (years)	Integer
IS_CALIB(inumind)	Technology survival curve calibration constant (user-specified)	Integer
IS_CAPCOST(inumind,maxstep,maxtech)	Technology capital cost (dollars per thousand metric tons of throughput capacity)	Real
IS_EMISS(inumind,maxstep,maxtech)	Technology CO_2 emissions (metric tons CO_2/thousand metric tons throughput)	Real
IS_FISYR	First calculated year	Integer
IS_FUEL_USE(inumind,maxstep, is_maxfuel,maxtech)	Fuel intensity for 1=electricity, and 2=natural in MMBtu/thousand metric tons throughput	Real
IS_LIFETIME(inumind)	Lifetime of added capacity (years)	Real

Input data	Description	Type
IS_LOGIT_COEFF(inumind,6,maxstep)	Logit coefficients for (1) fixed costs, (2) fuel costs, and (3) CO_2 emissions	Real
IS_NUMFUEL(inumind,maxstep)	Number of fuels in each step	Integer
IS_NUMTECH(inumind,maxstep)	Number of technologies in each step	Integer
IS_PRODUCTION(inumind,maxstep)	Historical step production (thousand metric tons); also known as PRODCUR	Real
IS_REI(inumind,maxstep,maxtech)	Relative energy intensity for state-of-the-art technology	Real
IS_WACC(inumind)	Weighted-average cost of capital (WACC)	Real
MECS_Data(inumind,5,10)	MECS benchmark factors for electricity, natural gas, residual fuel, steam coal, distillate, propane heat and power, petcoke, renewables, met coal, and other petroleum	Real
OBSOLETEYR(inumind,maxstep,maxtech)	Technology obsolescence year	Real

Source: U.S. Energy Information Administration

Industry-level steam coal benchmarking — ind_coal.csv

This file contains steam coal consumption values by manufacturing industry estimated for 2018–2023 using data from EIA's *Quarterly Coal Report* (QCR). The QCR gives data by three-digit NAICS code. In the cases where the three-digit NAICS code does not exactly line up with IDM industry NAICS definitions, it is decomposed into its relevant constituents apportioned according to the MECS consumption data and then mapped onto the corresponding IDM industry.

Table B-17. Allocation and weighting of *Quarterly Coal Report* industrial coal consumption data

NAICS code	NAICS classification	Weight	IDM industry code	IDM classification
311	Food manufacturing	1	7	Food products
312	Beverage and tobacco product manufacturing	1	24	Miscellaneous finished goods
313	Textile mills	1	24	Miscellaneous finished goods
322	Paper manufacturing	1	8	Paper and allied products
324	Petroleum and coal products			
32411	Petroleum refineries	0		(Handled by LFMM)
324199	Other petroleum and coal products	1	12	Iron and steel
325	Chemical manufacturing			
32511	Petrochemicals	0	9	Bulk chemicals – organic
325120–325180	Industrial gases, other basic inorganic chemicals	0.2538	9	Bulk chemicals – inorganic
32519	Ethyl alcohol, cyclic crudes, intermediate and gum and wood chemicals, other basic organic chemicals	0.6846	9	Bulk chemicals – organic
3252	Plastics materials and resins, synthetic rubber, artificial and synthetic fibers and filaments	0.0375	9	Bulk chemicals – resins

NAICS code	NAICS classification	Weight	IDM industry code	IDM classification
3253	Nitrogenous fertilizers, phosphatic fertilizers	0.0221	9	Bulk chemicals – agricultural
3254–3256	Pharmaceuticals and medicines, unspecified	0.0019	21	Light chemicals
3259	Photographic film, paper, plate, and chemicals	0	21	Light chemicals
327	Nonmetallic mineral products manufacturing			
3271	Clay building material and refractories	0.0159	22	Other non-metallic minerals
3272	Flat glass, other pressed and blown glass and glassware, glass containers, glass products from purchased glass	0.0013	10	Glass and glass products
327310	Cements	0.5608	11	Cement and lime
327320		0	22	Other non-metallic minerals
327330		0	22	Other non-metallic minerals
327390		0	22	Other non-metallic minerals
327410	Lime	0.3333	11	Cement and lime
327420	Gypsum	0	22	Other non-metallic minerals
327993	Mineral wool	0.0013	10	Glass and glass products
331	Primary metal manufacturing			
331110	Iron and steel mills and ferroalloys	0.9819	12	Iron and steel
3312	Steel products from purchased steel	0.0036	12	Iron and steel
3313	Alumina and aluminum	0	13	Aluminum
3314	Nonferrous metals, except aluminum	0.0145	23	Other primary metals
3315	Foundries	0	23	Other primary metals
333	Machinery manufacturing	1	15	Machinery
336	Transportation equipment manufacturing	1	17	Transportation equipment
339	Miscellaneous manufacturing	1	24	Miscellaneous finished goods

Source: U.S. Energy Information Administration

The QCR values overwrite the steam coal consumption totals for manufacturing industries in the years covered by ind_coal.csv. Regional splits are based on MECS consumption data. Base year steam coal consumption for process flow industries more closely matches the QCR values because the QCR values replace the process flow MECS values read in from ironstlx.xlsx (this is done in subroutine ISEAM). Process flow industry steam coal consumption for other covered years and end use industry steam coal consumption for all covered years do not exactly match the values in ind_coal.csv because of fuel-level SEDS benchmarking. For years after those covered by ind_coal.csv, for each industry, the subroutine CALIBRATE_COAL_ELEC applies the benchmark factor from the last ind_coal.csv year (that is, the ratio of the QCR value to the model output, by industry) to the consumption variables QTYMAIN, ENPMQTY, ENSQTY, and BYPBSCM.

We subtract ethanol plant coal consumption from the QCR data for industry index 9 because LFMM models ethanol plant consumption. We also subtract steam coal used to produce synthetic natural gas (town gas) from the QCR data for industry index 12 because it is modeled in NGMM.

Industry-level steam electricity benchmarking — ind_electric.csv

This file contains purchased electricity consumption by manufacturing industry estimated for 2018–2021 using data from the U.S. Census Bureau's Annual Survey of Manufactures (ASM). Unlike the QCR, the ASM provides electricity data by six-digit NAICS code and does not need to be further decomposed. Otherwise, it uses the same NAICS to IDM mapping as ind_coal.

The subroutine CALIBRATE_COAL_ELEC ASM overwrites the purchased electricity totals for manufacturing industries in the years covered by ind_electric.csv, except for the base year. Unlike the QCR benchmarking, we do not overwrite the base year MECS values. Regional splits are based on MECS consumption data. Purchased electricity values for covered years do not exactly match the values in ind_electric.csv because of fuel-level SEDS benchmarking. For years after those covered by ind_electric.csv, for each industry, the subroutine applies the benchmark factor from the last ind_electric.csv year (that is, the ratio of the ASM value to the model output, by industry) to the consumption variables QTYMAIN, ELOWN, ENPMQTY, ENSQTY, and BYPBSCM.

Feedstock history and projections—feedstock.csv

This file contains historical industrial feedstock consumption data for the entire United States from the IDM base year through the last SEDS year as well as projections through the STEO year. The feedstock data are for natural gas, ethane, propane, propylene, normal butane, isobutane, natural gasoline, naphtha, and H_2 used for fertilizer production. The data are based on EIA survey data of natural gas, hydrocarbon gas liquids, and naphtha. The projected feedstock consumption is based on a combination of research into planned petrochemical and fertilizer projects, preliminary survey data, and analyst judgment.

The subroutine READ_FEEDSTOCK reads the data from feedstock.csv and populates the variables shown in Table B-18.

Table B-18. Feedstock.csv feedstock history and projections input data

Input data	Description	Units
MAX_YEARS	Year index going from the base year (1) to the last STEO year	Index
FEEDNGTOTAL	Natural gas feedstock	trillion Btu
FEEDLPGTOTAL	Total hydrocarbon gas liquid feedstock (sum of ethane, propane, propylene, normal butane, isobutane, and natural gasoline)	trillion Btu
FEEDETHTOTAL	Ethane feedstock	trillion Btu
FEEDPROPANETOTAL	Propane feedstock	trillion Btu
FEEDNORMBUTANETOTAL	Normal butane feedstock	trillion Btu
FEEDISOBUTANETOTAL	Isobutane feedstock	trillion Btu

FEEDPROPYLENETOTAL	Propylene feedstock	trillion Btu
FEEDNATGASOLINETOTAL	Natural gasoline feedstock	trillion Btu
FEEDNAPHTOTAL	Naphtha feedstock	trillion Btu
H2_FEED	H_2 feedstock used for fertilizer production (not populated for STEO years)	trillion Btu

Source: U.S. Energy Information Administration

Ethane feedstock census region split — ethanereg.csv

This file contains the fraction of total U.S. ethane feedstock consumption in each census division, by year. The data go from 1990 through typically the third or fourth year after the last STEO year. The regional split is based on EIA's internal database on petrochemical cracking capacity at the plant level. No ethane feedstock is consumed in New England (division 1), the South Atlantic region (division 5), the Mountain region (division 8), or the Pacific region (division 9).

The subroutine READ_ETH_FRAC populates the variable EthaneDivFrac(IYR, ICD) with the data from this file, where IYR is the index year (with 1990=1) and ICD is the census division.

Propane feedstock census region split – propanereg.csv

This file contains the fraction of total U.S. propane feedstock consumption in each census region, by year. The data go from 1990 through typically the third or fourth year after the last STEO year. The regional split is based on EIA's internal database on petrochemical cracking capacity at the plant level and reported product supplied numbers in EIA's *Petroleum Supply Annual*. No propane feedstock is consumed in New England (division 1), the Middle Atlantic region (division 2), the South Atlantic region (division 5), the Mountain region (division 8), or the Pacific region (division 9).

The subroutine READ_PROP_FRAC populates the variable PropaneDivFrac(IYR, ICD) with the data from this file, where IYR is the index year (with 1990=1) and ICD is the census division.

Base year hydrogen supply and demand — ind_H2.csv

This file contains hydrogen supplied to and demanded by six bulk chemical subsectors in the IDM base year (in TBtu): industrial gases (NAICS 325120), other inorganics (NAICS 325180), petrochemicals (NAICS 325110), other organics (NAICS 325194), resins (325211), and agricultural chemicals (NAICS 325311 and 325312). The file also contains hydrogen supply for refining. The bulk chemical subsector data are by census region, and the refining hydrogen data are by census division. The refining demand row is all zeros, but this is not because refining demand is zero, but because the subroutine code needs numbers in that row to function. Actual IDM base year hydrogen demand for refining is modeled in LFMM.

The bulk chemicals hydrogen demand represents the amount of hydrogen feedstock the subsector and region consumed in the IDM base year (excluding any byproduct hydrogen that is produced and consumed onsite). The supply represents the amount of non-byproduct hydrogen produced onsite. If supply is greater than demand for a subsector in a given region, we assume the excess hydrogen is sold. If supply is less than demand for a subsector in a given region, we assume hydrogen is purchased to meet the demand. We assume the industrial gases sector does not consume any hydrogen but instead supplies it to the other demand sources.

Short-Term Energy Outlook *variables — steovars.csv*

Multiple modules use this file to pull in Short-Term Energy Outlook (STEO) values. The INDEASY subroutine pulls the STEO variables shown in Table B-19 and puts them in the IDM variables shown in the same table.

Table B-19. STEO variables pulled into the IDM from steovars.csv

STEO variable name	STEO variable description	Units
ETTCBUS	Ethane/ethylene product supplied	Real: quadrillion British thermal units (Btu)
C4TCBUS	Butanes/butylenes product supplied	Real: quadrillion Btu
PRTCBUS	Propane/propylene product supplied	Real: quadrillion Btu
PPTCBUS	Natural gasoline (pentanes plus) product supplied	Real: quadrillion Btu
DFTCBUS	Distillate fuel oil product supplied	Real: quadrillion Btu
RFTCBUS	Residual fuel oil product supplied	Real: quadrillion Btu
MGTCBUS	Motor gasoline product supplied	Real: quadrillion Btu
FETCBUS	Petrochemical feedstocks product supplied	Real: quadrillion Btu
ARTCBUS	Asphalt and road oil product supplied	Real: quadrillion Btu
LUTCBUS	Total lubricants consumed	Real: quadrillion Btu
PCTCBUS	Petroleum coke product supplied	Real: quadrillion Btu
WXTCBUS	Total waxes consumed	Real: quadrillion Btu
ABTCBUS	Aviation gasoline blend components refinery input	Real: quadrillion Btu
UOTCBUS	Unfinished oils product supplied	Real: quadrillion Btu
MSTCBUS	Miscellaneous petroleum products consumed	Real: quadrillion Btu
SNTCBUS	Special naphthas consumed	Real: quadrillion Btu
NGNUKUS	Btu/cubic foot natural gas, U.S. total	Real: quadrillion Btu
NGINX	Natural gas consumption industrial sector, U.S. total	Real: trillion cubic feet
ZSAJQUS	Days in year	Real: days
CLYCBUS	Other industrial coal consumption	Real: quadrillion Btu
CLKCBUS	Coke plants coal consumption	Real: quadrillion Btu
CCNIBUS	Coal coke net imports into the United States	Real: quadrillion Btu
EXICPUS	Electricity consumed by (sold to) the industrial sector	Real: billion kilowatthours
HVICBUS	Industrial sector consumption of conventional hydroelectric energy	Real: quadrillion Btu
HVCCBUS	Commercial sector consumption of conventional hydroelectric energy	Real: quadrillion Btu
WWICBUS	Industrial sector consumption of wood and wood waste biomass energy	Real: quadrillion Btu
OWICBUS	Industrial sector consumption of non-wood waste biomass energy (municipal solid waste)	Real: quadrillion Btu

STEO variable name	STEO variable description	Units
PCEPCONB	Electricity sector consumption of petcoke	Real: quadrillion Btu
PMTCPUS	Marketable petcoke (including industrial and power sector consumption, but not refinery consumption)	Real: million barrels per day
PCTCZUS	Petcoke heat content	Real: million Btu per barrel

Source: U.S. Energy Information Administration, *Short-Term Energy Outlook* (STEO)

Note: Units reflect the STEO variables after they have been converted to annualized values in the Integrating Module, but before they are converted to any other units by the IDM.

Industrial Demand Module hardcoded data

The Industrial Demand Module currently has hardcoded data that needs to be updated occasionally.

Table B-20. Hardcoded variables in the Industrial Demand Module

Variable	Subroutines	Industry	Explanation
AG_BLDG_WT(3,8)	AGTPC	Agriculture	Weights of building energy consumption for each fuel (second index, 1=electricity, 2=natural gas, 3=distillate, 4=propane, 5=gasoline, 6=other petroleum, 7=steam) for each major use (first index, 1=heating, 2=lighting, 3=building shell) for the agriculture industry
ALEFFICIENCY(4)	CALPROD	Aluminum	Electrical efficiency data for aluminum
ALINTERCEPT(4)	CALPROD	Aluminum	Intercept term for regression of primary aluminum ratio to total aluminum production on electricity prices
ALSLOPE(4)	CALPROD	Aluminum	Electricity price term from regression of primary aluminum ratio to total aluminum production on electricity prices
ALSLOPELAG(4)	CALPROD	Aluminum	Lagged electricity price term from regression of primary aluminum ratio to total aluminum production on electricity prices
AVEBEFF(11)	CALBSC	All except iron and steel, paper, and aluminum	Average boiler efficiency for boilers by type of fuel (1=natural gas, 2=steam coal, 3=residual fuel, 4=distillate, 5=propane, 6=electricity, 7=petcoke, 8=other petroleum, 9=biomass, 10=hydropower, 11=total)
BEFF(11)	CALSTOT	All except iron and steel, paper, and aluminum	Average boiler efficiency for boilers by type of fuel; identical to AVEBEFF (1=natural gas, 2=steam coal, 3=residual fuel, 4=distillate, 5=propane, 6=electricity, 7=petcoke, 8=other petroleum, 9=biomass, 10=hydropower, 11=total)
BIOFACTOR	CALGEN	All except iron and steel, paper, and aluminum	Incremental biomass capacity available for CHP
BIOCAPFAC	CALGEN	All except iron and steel, paper, and aluminum	Capacity factor of CHP biomass capacity
BYPBEFF(6)	CALGEN	All except iron and steel and paper	Boiler efficiency by fuel for byproduct fuels
BYPCSC(3,5,maxstep)	CALBYPROD	All except iron and steel and paper	Byproduct fuel UECs
ClinkFac		Cement	Converts metric tons of clinker to metric tons of elemental carbon equivalent

Variable	Subroutines	Industry	Explanation
COGGRDNEW	CALGEN	All except iron and steel and paper	Assumed grid share for new CHP capacity additions
CoalPFac	CALBSC	All except iron and steel, paper, and aluminum	Factor to multiply price to account for non-price costs associated with coal use
CON_PROXY_WT(3,5)	CONTPC	Construction	Weights of building energy consumption for each fuel (second index, 1=electricity, 2=natural gas, 3=distillate, 4=propane, 5=gasoline) for each major use (first index, 1=heating, 2=lighting, 3=building shell) for the construction industry; not used as of AEO2025
MetlShr(16:60)	OTH_MINTPC	Mining	Share of other mining (metal and minerals) that is metal mining
NgasPFac	CALBSC	All except iron and steel, paper, and aluminum	Factor to multiply price to reflect natural gas as premium fuel
OGSM_MAP(7,4)	OGSMTPC	Oil and natural gas mining	Maps Hydrocarbon Supply Module (HSM) regions to census regions
OilPFac	CALBSC	All except iron and steel, paper, and aluminum	Factor to multiply price to account for non-price costs associated with residual fuel oil use
PROD_WT(7)	OGSMTPC	Oil and natural gas industries	Factors reflecting relative difficulty of extraction by fuel type (see Table 13)
RegCHPScore(4)	CALGEN	All except iron and steel, paper, and aluminum	Regional CHP penetration adjustment based on ACEEE Scorecard friendliness factor
TPC_FAC_WT(6,3)	OGSMTPC	Oil and natural gas mining	Shares of energy use by fuel (first index, 1=electricity, 2=natural gas, 3=distillate, 4=gasoline, 5=renewables, 6=residual oil) and by HSM driver (second index, 1=vehicles, 2=production factor, 3=dry well index)
WEIGHT_CON(4,3,5)	CONTPC	Construction	Construction industry regional (first index) shares of fuel consumption (third index, 1=electricity, 2=natural gas, 3=distillate, 4=other petroleum, 5=gasoline) for each major use (second index, 1=buildings, 2=civil engineering, 3=trade). Not used in AEO2025.
WPrep_Initial, WPrep_Final	PRODFLOW_PAPER	Paper	PRODFLOW coefficients for mechanical pulp, semi-chemical pulp, and Kraft pulp in 2010 and 2020, respectively

Source: U.S. Energy Information Administration

Appendix C. Carbon Capture and Sequestration in Cement

Clarify cement emissions factor:

NETL document on cement plant carbon capture and sequestration (CCS) retrofits claims 0.922 metric tons CO_2 emitted/metric ton cement produced (see page 29 of https://www.osti.gov/servlets/purl/1970135). This comports with (more or less) the derived emissions intensity from the AEO2023:

According to the U.S. Geological Survey's Mineral Commodity Summary[50], 86.4 million metric tons cement were produced in 2018; from 2018–2022, cement shipments grew by 7.6/6.628 to give 86.4 * (7.6/6.628) = 99.1 million metric tons cement produced in 2022. AEO2023 emissions (combustion + process) = 31 + 57 = 88 million metric tons, which implies a total emissions factor of 88 / 99.1 = 0.89 metric tons CO_2/metric ton cement.

Note that USGS for 2022 shows total cement production at 93 million metric tons, and with the AEO2023 emissions set at 88 million metric tons, the emissions factor by this measure is 88/93 = 0.946, which again is close to the NETL value of 0.922 metric tons CO_2/metric ton cement produced. Note again that this emissions factor accounts for both combustion *and* process emissions, which comports with the fact that NETL CCS costs and fuel use assumptions are derived assuming that the CCS retrofits capture both kinds of CO_2 emissions.

Note also that the process emissions factor is currently embedded (hardcoded) in the IDM as 0.507 metric tons CO_2/metric ton cement.

Despite the fact that in 2018 there was (86.4 million metric tons cement produced) * (0.89 metric tons CO_2/metric ton cement produced) = 76.9 million metric tons CO_2 emitted, the official NETL database has only a national total of 72.2 million metric tons CO_2 *capturable* (see table below)—in other words, NETL assumes that not all of the CO_2 generated from making cement can be captured. More precisely, the NETL cement database assumes a maximum capture rate of 95%, and 95% of the USGS total CO_2 emitted in 2018 (76.9 million metric tons * 0.95 = 73.1 million metric tons) is very close to the total national CO_2 capturable in the NETL(201-003) CCRD ("Carbon Capture Retrofit Database").

Note the capture rate varies somewhat within the NETL archives. From the data plant database itself, the capture rate appears to be 97% as defined by "CO_2 Captured" / "Equivalent Cement Capacity". But the "User Input" of the NETL database claims a 90% capture rate, and the NETL analyses of retrofit cases assume a 95% capture rate https://netl.doe.gov/sites/default/files/netl-file/23CLD_Grol.pdf. We chose to use 95% here.

General notes on cost of capture (COC) for cement kiln CCS retrofits

The main source of costs (both variable and fixed) for the CCS retrofits was NETL's 2018 Carbon Capture Retrofit Database (CCRD). Updates to the retrofit costs are available from NETL here:

[50] U.S. Geological Survey "Mineral Summary—Cement", Washington, DC, January 2023, https://pubs.usgs.gov/periodicals/mcs2023/mcs2023-cement.pdf

https://netl.doe.gov/energy-analysis/search?search=IndustrialRetrofitLegacy. Note that all NETL CCRD tools/spreadsheets from 2018 onwards seem to have the same dollar year basis, so all provided COCs are in 2018 real dollars.

It is important to remember that in the modeling described below, the CO_2 emissions captured are from *both* combustion and process emission sources. The assumption in the NETL work described below is that all CO_2, regardless of whether it was from the burning of fuels or the baking of limestone, is equally susceptible to capture using the NETL-assumed CCS retrofit equipment.

Table C-1. Carbon capture and sequestration parameters from NETL

	$/metric ton CO_2	total CO_2 capturable (thousand metric tons)	minimum CO_2 capture cost $/metric ton (lowestCCS)*
national	69.7	72,214	
CR1	87.2	4,836	70.4
CR2	61.7	20,646	52.1
CR3	66.2	30,804	51.3
CR4	81.5	15,929	65.9

Source: NETL's 2018 Carbon Capture Retrofit Database

Note: All costs and prices in 2018 real dollars.

The lowestCCS variable (which is read in from the cement tab of the ironstlx.xlsx input file) is a key input because it represents the lowest COC in a given census region and thus is the "base" that is shifted because of changing fuel costs or changing capital costs over the projection period. There is no national value for lowestCCS because IDM computes everything at the regional level.

<u>Methodology and formulation for generating the CO_2 capture (supply) curves for each of the four Census Regions</u>

General methodology note: In the enumerated sections below, we outline the procedure to set up a distribution of COC for retrofit CCS equipment on cement kilns. This approach is to be distinguished from a plant-by-plant approach where all cement kilns are evaluated individually based on each of their own economic viability for installing CCS retrofit equipment. Specifically, the individual plant COCs are aggregated into a single functional "supply curve" which can then be analytically shifted by changing variable costs.

<u>Transform each (census) regional total COC and fit to an exponential curve</u>:

1. Take the natural log of CO_2 captured and regress ln(CO_2 captured) vs. COC (columns J and I in the CR# tabs):

   Assume a functional form of

$$CO_2\ captured = a * \exp\left(b * COC\right)$$

$$\ln(CO_2\ captured) = \ln(a) + b * COC$$

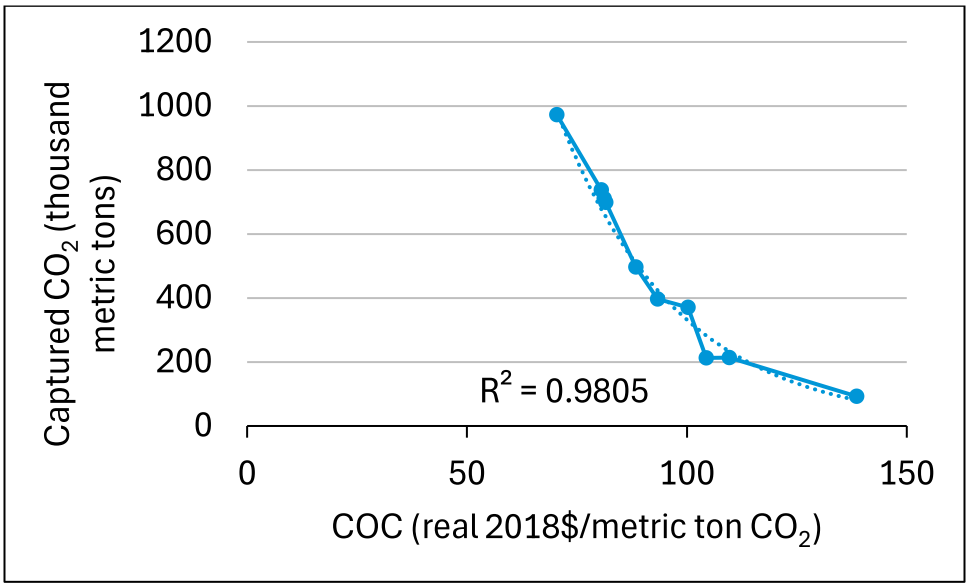
Do a linear regression of *ln(CO_2 captured)* vs. *COC* to get $y\ intercept = \ln(a)$ and $slope = b$.

The fitted exponential curve is which provides the amount of CO_2 captured at a *particular COC* (as opposed to a cumulative amount of CO2 captured) is:

$$CO_2\ captured = exp(y\ intercept) * exp(slope * COC)$$

Note that in this regression analysis the *b* parameter (i.e., the slope from the regression) is negative, meaning that the data fits a decaying exponential curve (shown below) which plots each census region's aggregate cement plant's CO_2 capture potential (in thousand metric tons) versus its respective *COC*.

Figure C-1. Raw data and exponential fit of CR1 plants



Source: U.S. Energy Information Administration

2. Now convert this exponential curve/distribution into a standard exponential distribution (this will prove useful later because it will allow us to easily alter the mean of the distribution based on varying capital and operations and maintenance cost assumptions):

$$\left(\frac{1}{\beta}\right)\exp\left[-(x-\mu)/\beta\right]$$

So then

$$\beta = \frac{-1}{b} = \frac{-1}{slope} \text{ and } \mu = \left(\frac{-1}{slope}\right)\ln\left[\frac{exp(y\ intercept)}{(-slope)}\right] = \left(\frac{-1}{slope}\right) * [y\ interpect - ln(-slope)]$$

Recall that the *slope* < 0 (since the fitted curve as noted above is a decaying exponential) so the above equation is valid with respect to the domain of the natural logarithm function. Although this standard form of the fitted COC exponential cost distribution will not be employed in the actual IDM CTUS model, it will be referred to below when formulating the shifted cost curve.

3. Find the mean of the distribution using the fitted exponential parameters in #1:

$$\text{Let } I = \int_{COC_l}^{COC_u} \exp(y\ intercept) * \exp(slope * COC)\, d(COC)$$

where we are integrating over the fitted exponential function. In the above equation, the lower bound of the integral *COC_l* is the COC of the cement kiln with lowest cost of capture in a given region, and the upper bound of the integral *COC_u* is the COC of the cement kiln with the most expensive cost of capture. Now we need to find the value of *COC* (the upper limit in the integral) such that:

$$I/2 = \exp(y\ intercept) \int_{COC_l}^{COC} \exp(slope * COC)\, d(COC)$$

This occurs when

$$COC \equiv COC_{1/2} = \frac{1}{slope} \ln\left[\frac{slope * (I/2)}{\exp\,(y\ intercept)} + exp(slope * COC_l)\right]$$

Thus, the $COC_{1/2}$ in the above equation represents the mean of the distribution since half of the distribution is to either side of $COC_{1/2}$. We interpret this mean as the "average COC" for each region.

4. Find the national average COC and for each census region:

While the above result for the mean of the distribution may be useful theoretically later on, for practical purposes we'll need the average COC nationally and for each census region in order to calibrate the regional costs with the latest average COC from the 2023 cement retrofit report https://www.osti.gov/servlets/purl/1970135. In the spreadsheet on the "cement results" tab, the weighted average COC from the CCRD database is computed via

$$COC_{national\ average} = \frac{1}{\sum_{i \in all\ cement\ plants} capacity_i} \sum_{i \in all\ cement\ plants} capacity_i * COC_i$$

where each cement plant's COC_i is weighted by its cement production capacity variable index $capacity_i$; these average capture costs (which include both fixed and operations and maintenance costs) are shown below. Note that the weighting over cement production capacity was done since the potential CO_2 captured from each plant is proportional to the size of the plant (that is, the more cement produced the more CO_2 emitted, neglecting small variations in operational and fuel use).

The above equation can also be used to compute a given census region's (CRn; n = 1, 2, 3, 4) average COC via:

$$COC_{CRn} = \frac{1}{\sum_{i \in CRn\ cement\ plants} capacity_i} \sum_{i \in CRn\ cement\ plants} capacity_i * COC_i$$

Using these equations, the average COCs for each census region and nationally, weighted by cement plant capacity from the individual kilns in the CCRD database, are below in 2018 real \$/metric ton CO_2:

Table C-2. NETL cement plant costs of capture

	NETL plant-level data for actual weighted average COCs	**Mean of exponential distribution $COC_{1/2}$**
National	69.6	
CR1	85.5	87.2
CR2	65.2	61.7
CR3	64.7	66.2
CR4	79.5	81.5

Source: U.S. Energy Information Administration, based on NETL's 2018 Carbon Capture Retrofit Database

Note that these average regional COCs do not precisely equal the "mean of the distribution" computed in #3 above; this is because the "mean of the distribution" (shown in the green values) computed in #3 is based on a fitted exponential curve whereas the computation of the average COC here in #4 is based directly on the actual data of the cement kilns itself. Finally, note that use of the cement kiln capacity as a weight as opposed to weighting by the CO_2 captured for each plant is irrelevant since according to the CCRD database the CO_2 captured is always the same multiple of the cement capacity (based on an assumed universal emissions factor and captured rate of 95%).

5. Creating a supply curve from the exponential distribution function:

The *cumulative* distribution function from the fitted exponential distribution shown above will provide the supply curve for the COC and amount of CO_2 supplied at a given price:

$$F(COC) = N \int_{COC_i}^{COC} \exp(y\ intercept) * \exp(slope * COC')\, d(COC')$$

where

$$COC_i \leq COC \leq COC_f$$

and COC_i = lowest capture cost in a given region while COC_f= highest capture cost in a given region.

On purely economic terms, in any given year, for a given price of CO_2 in real \$/metric ton, the amount of CO_2 that is theoretically capturable is

$$F(COC^* = price\ CO_2) = N\ \frac{\exp(y\ intercept)}{slope}[\exp(slope * COC^*) - \ \exp(slope * COCi)].$$

In other words, all CO_2 that can be captured for a cost less than the price offered for CO_2 is profitable to be captured. If the entire 45Q tax credit went to the cement kilns, and there were no transportation and sequestration costs, then the “price” would be $85/metric ton. Though we assume only a portion of the economic capturable CO_2 will actually be retrofitted with CCS.

N is a normalization factor necessary to make sure that the cumulative amount of captured CO_2 at the highest price on the supply curve (*COCf*) is the total amount of captured CO_2 possible in that region, that is, at cost *COCf* all CO_2 (based on the fitted exponential curve derived in #1 above)

$$\sum_{i\in all\ kilns} COC\ captured_i = \exp(y\ intercept) \sum_{i\in all\ kilns} \exp(slope * \ COC_i)$$

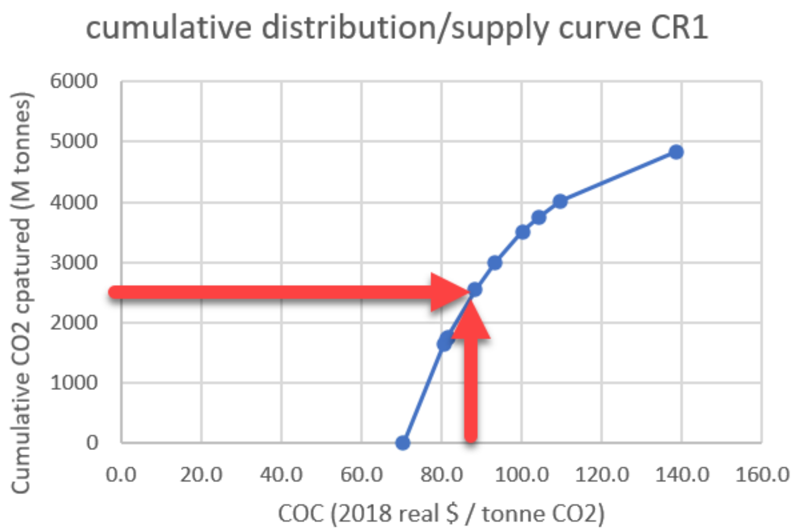
must equal the cumulative CO_2 at the last point on the supply curve at $F\left(COC_f\right)$. Thus, we must have for the normalization constant:

$$N = \frac{slope * \exp(y\ intercept)\ \sum_{i\in all\ kilns} \exp(slope * \ COC_i)}{\exp(y\ intercept) * \left[exp\left(slope * COC_f\right) - \exp\ (slope * COC_i)\right]}$$
$$= \frac{slope * \sum_{i\in all\ kilns} \exp(slope * \ COC_i)}{\left[\exp\left(slope * COC_f\right) - \exp\ (slope * COC_i)\right]}$$

Note: the normalization constant is not the same as the integral *I* of the original fitted exponential distribution, because the spacing between increments in the plant-level *COC*s in the numerical integral are not uniform and not equal to 1. Thus, the cumulative distribution (the supply curve) must be “normalized” to equal the total capturable CO_2 in a given region.

An example of the supply curve (which again is represented by the cumulative distribution function computed above) is shown below for census region 1 (this is in 2018 real dollars):

Figure C-2. Example cumulative distribution supply curve.



Source: U.S. Energy Information Administration

The red arrow points to the mean of the original distribution $COC_{1/2}$ computed earlier in step #3 above. What this means is that at a CO_2 price equal to the mean COC shown by the red arrow, up to about 2,400 metric tons CO_2, which is half of the capturable CO_2 in census region 1. Note also that at the final *COC* the cumulative CO_2 captured is 4836 thousand metric ton, which is in fact (using the above equations for *F(COC)* at *COCf* and *N*, we arrive at

$$F(COC_f) = \sum_{i \in all\ kilns} \exp(slope * \ COC_i)$$

which is what we expect, that is, the total accumulated CO_2 captured is the sum of all captured CO_2 at every *COC*.

Note that the graphic above looks like an "inverted" supply curve that we normally see because here we graph quantity (of CO_2 captured) vs. price (*COC*) instead of the usual price versus quantity.

Delineating capital and variable costs in the COC computations:

Consistent with the fuel rate use assumptions above (see previous "Fuel rates for cement retrofit CCS operations" section), for the CM95-B case (Exhibit G-9 on page 251 of https://www.osti.gov/servlets/purl/1970135), the total cost of COC for the "standard" equipment is \$65.8/metric ton CO_2 (in real 2018 dollars). This is broken down (according to the aforementioned Exhibit G-9) as follows:

Capital cost = \$22.00/metric ton CO_2 (assumes 30 year payback and 5.15% annual borrowing interest rate)

Fixed O&M = \$10.50/metric ton CO_2

Variable O&M (not including fuel costs) = \$7.20/metric ton CO_2

Fuel costs = \$26.00/metric ton CO_2 (note that this fuel cost assumes natural gas and purchased power prices that are dynamic for the IDM COC cost calculations).

Note that the sum of the four cost components above = \$65.80/metric ton CO_2, which is largely consistent with the overall retrofit cost determined in another (2022) NETL study on CCS costs (see Exhibit ES-2 on page 3 of https://www.osti.gov/servlets/purl/1887586).

For the purposes of computing the COC in the IDM, we keep costs in 2018 real dollars. However, in the IDM code this will necessitate transforming the 45Q tax credit of \$85/metric ton CO_2 captured (for non-enhanced-oil-recovery CCS) which is in 2022 real dollars into 2018 real dollars (though the credit is adjusted for inflation after 2026: https://crsreports.congress.gov/product/pdf/IF/IF11455). The deflator MC_JPGDP is used to make any real dollar adjustments.

Note on deflator: NEMS has a global variable array (dimensioned by year but not by census region or census division) representing the deflator MC_JPGDP(IX) where the index IX = -2 (1987) through 61 (2050). The deflator values are relative to 1987, which is why MC_JPGDP(-2) = 1.0 and all subsequent index values result in a higher value than 1.0 for the relative deflator (the index = -2 corresponds to year 1987). For CCS implementation purposes with the new module CCATS (Carbon Capture, Allocation, Transportation and Sequestration) in NEMS, the NETL prices are provided in 2018 real dollars, but CCATS requires their costs and prices in 1987 dollars. Therefore, the 2018 real dollar prices for capital and non-fuel O&M costs must be converted to 1987 real dollars by dividing the costs by MC_JPGDP(29). Note that fuel costs in the IDM are computed using the variables prcx(fuel, ICR, 2) where the index fuel = 1 is for purchased electricity and fuel = 2 is for natural gas are already in 1987 real dollars, and index ICR is census region.

To deal with the dynamic fuel costs, we start with the fuel rates for cement retrofit CCS operations, from https://www.osti.gov/servlets/purl/1970135 Exhibit 5-15 page 41:

Natural gas use = 16,374 MMBtu/day * (365 days)/[(1,500,000 metric tons cement/year)*(0.85)*(0.922 metric tons CO_2/metric ton cement)] = 5.08 MMBtu/metric ton CO_2

Electricity use = (20 MW)*(24 hours)*(365 days)*(1000 kWh/MWh)*(3412 Btu/MWh) = 597,782 MMBtu

Then 597,782 MMBtu/[(1,500,000 metric tons cement/year)/[(1,500,000 metric tons cement/year)*(0.85)*(0.922 metric tons CO_2/metric ton cement)] = 0.509 MMBtu/metric ton CO_2

Using current (AEO2025) U.S. delivered energy prices for the industrial sector, \$4.54/MMBtu for natural gas and \$23.40/MMBtu for purchased electricity in 2022 dollars, or multiplying by the 2018 versus 2022 deflator of (1.925/2.220) = 0.867 to get $3.93/MMBtu for natural gas and $20.30/MMBtu for purchased electricity in 2018 dollars, we get for the fuel costs:

Natural gas: (5.08 MMBtu/metric ton CO_2) * ($3.93/MMBtu) = $20.00/metric ton CO_2 (in 2018 dollars)

= $10.40/metric ton (in 1987 dollars)

Purchased electricity: (0.509 MMBtu/metric ton CO_2) * ($20.30/MMBtu) = $10.30/metric ton CO_2 (in 2018 dollars)

= $5.40/metric ton CO_2 (in 1987 dollars)

So we see that the total fuel costs roughly are about $30.30/metric ton CO_2 (in 2018 dollars) or $15.70/metric ton CO_2 in 1987 dollars.

The above calculations for fuel use rate for natural gas and electricity assume a 0.85 capacity utilization of a 1.5 million metric ton/year cement plant with a 0.922 metric ton CO_2/metric ton cement emission factor (again, the emission factor is on page 29 https://www.osti.gov/servlets/purl/1970135).

The above gives an estimate of the fuel costs on a national level, but in the IDM fuel costs are computed on a census region level by using the IDM variable prcx(fuel, CR ,2) (fuel = 1 for purchased electricity, fuel = 3 for natural gas, CR = census region 1–4). As noted previously, these prcx(fuel, CR, 2) prices are in 1987 dollars, so they must be inflated to 2018 dollars to compare with the other NETL costs. This is done by multiplying the prcx prices by MC_JPGDP(29).

Using the historical NEMS fuel prices for 2018 (and converting them from 2022 real dollars to 2018 real dollars), we compute the fuel costs and subtract that from the total average costs for each region (note that the total average costs are the average of the fitted exponential distribution, which is close to the average COC based on the NETL data). The remaining cost is comprised of variable operations and maintenance (O&M) costs, fixed O&M costs, and capital costs. We use the percentages of these remaining costs from the NETL reports for the CM95-B case (these costs are detailed above) to estimate our estimated versions of these three cost components. The table below summarizes the *average* costs in 2018 for each census region (costs in real 2018 dollars ($/metric ton CO_2):

Table C-3. Average CO_2 cost of capture (COC) components

CR	variable O&M	fixed O&M	capital	fuel	total COC
national	7.1	10.4	21.8	30.3	69.6
1	8.3	12.1	25.3	41.5	87.2
2	5.6	8.1	17.0	31.1	61.7
3	7.2	10.6	22.1	26.3	66.2
4	7.5	11.0	23.0	40.0	81.5

Source: U.S. Energy Information Administration, based on NETL's 2018 Carbon Capture Retrofit Database

Note that these are the *base* costs, and they will shift (along with their distributions) according to both updated assumptions regarding the capital cost as well as the changing fuel costs as fuel prices change in the projection (see section below). Note also that the total average *COC* costs in Table C-3 match the mean *COC* (that is, $COC_{1/2}$) from the derived exponential fit in Table C-2.

<u>Adjusting the "average" COC in the supply curve</u>:

The fuel prices change as NEMS runs, affecting the COC. The change in fuel prices is represented in the IDM by a shift in the capturable CO_2 supply curve.

In general, to arrive at a shifted supply curve from the "standard" (unshifted) supply curve derived in Section #5,

$$F(COC) = N\ \frac{\exp(y\ intercept)}{slope}\left[\exp(slope * COC) - \ \exp(slope * COC_i)\right]$$

we recognize that shifting the cumulative fitted exponential distribution (supply curve) above will have the same slope (which affects the curvature of the distribution) but a different y-intercept (note from the detail in Section #2 that only the slope affects the curvature of the exponential curve, but the mean can be shifted *in a linear fashion* by altering the y-intercept only).

Recall that the mean of the exponential fitted curve derived in Section #3 above, $COC_{1/2}$, is found by assuming that ½ of the area under the exponential fitted curve is the left and ½ of the area to the right (the very definition of the "mean"). As shown above in Section #3, the total cumulative CO_2 is given by integrating over the entire (fitted) exponential distribution:

$$I = \exp(y\ intercept) \int_{COCi}^{COCf} \exp(slope * COC)\, d(COC)$$

Shifting the exponential distribution by Δ (to the right or left) gives simply:

$$I = exp(y\ intercept) \int_{COCi+\Delta}^{COCf+\Delta} exp(slope * COC)\, d(COC)$$

which will not equal the original integral *I* unless the *y intercept* is altered. We can do this by taking the mean of the distribution (see Section #3 again):

$$COC_{1/2} = \frac{1}{slope} \ln\left[\frac{slope * (I/2)}{\exp\,(y\ intercept)} + \exp(slope * COC_i)\right]$$

which is derived from the analytical evaluation of the integral

$$I/2 = exp(y\ intercept) \int_{COCi}^{COC} exp(slope * COC)\, d(COC)$$

*Note: typically in the IDM, the shift itself (Δ) is comprised of two components: the **CapAdderCCS** (see "Capital Cost Adder" section below) parameter (read in from ironstlx.xlsx) and is meant to boost the* *capital cost from the unrealistic NETL capital cost which assumes a 30-year payback period as opposed to a more realistic 12-year payback period based on the duration of the 45Q tax credit; and, the difference between the 2018 fuel (natural gas and power) assumed costs under the NETL CCS retrofit assumptions and the current model year's fuel costs.*

Solving for the *y intercept* we get

$$y\ intercept = \ln\left[\frac{slope * (I/2)}{\exp\left(slope * \ COC_{1/2}\right) - \exp(slope * COC_i)}\right]$$

A shifted curve will move the $COC_{1/2}$ and COC_i by a given prescribed Δ (which could result from as mentioned above a change in fuel prices). This results in the changed *y intercept* as follows:

$$y\ intercept(shifted) = \ln\left[\frac{slope * (I/2)}{\exp\left(slope * [COC_{1/2} + \Delta]\right) - \exp(slope * [COC_i + \Delta])}\right]$$

Note that when we substitute the above shifted value *y intercept(shifted)* is employed in the integral below ranging from the shifted lower *COC* bound to the shifted mean:

$$\exp[y\ intercept(shifted)] \int_{COCi+\Delta}^{COC_{1/2}+\Delta} \exp(slope * COC)\, d(COC)$$

The result is *I/2*, as expected.

This "shifted" *y intercept* can now be employed in the shifted supply/cost curve, which will retain the same shape as before only it will be shifted to the left or right depending on the sign of Δ:

$$F(COC + \Delta) = N\ \frac{\exp[y\ intercept(shifted)]}{slope}[\exp(slope * [COC + \Delta]) - \ \exp(slope * [COC_i + \Delta])]$$

Note that this shifted supply curve/fitted cumulative exponential distribution above possesses the same slope (and therefore curvature) and normalization constant *N* as the unshifted curve. Note also that the first point on the shifted supply curve is $COC_i + \Delta$ and the last point is $COC_f + \Delta$, while the new mean is $COC_{1/2} + \Delta$.

Note that when $COC + \Delta = COC_{1/2} + \Delta$, i.e., when we are finding the cumulative CO_2 at the new mean (the mean of the shifted cost curve), substituting the *y intercept* expression in the above shifted equation reduces to

$$F\left(COC_{1/2} + \Delta\right) = N * \left(\frac{I}{2}\right)$$

as expected. Using this shifted supply/cost curve function, we can use the "price" of CO_2 sent to IDM from CCATS (that is, *COC**)

$$F(COC^*) = N\ \frac{\exp[y\ intercept(shifted)]}{slope}\left[\exp\left(slope * (COC^*)\right) - \ \exp(slope * [COC_i + \Delta])\right]$$

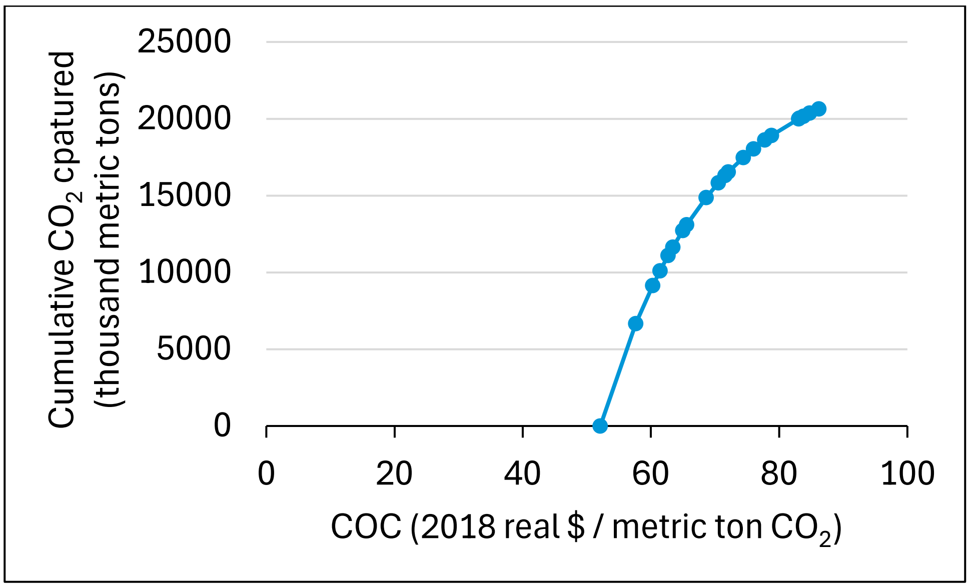
to compute the amount of CO_2 that is at least economic to capture (that is, all CO_2 on the cost curve up to the given CCATS price *COC**). Note that *COC** must be within the shifted domain of capture costs

$$COCi + \Delta \leq COC^* \leq COCf + \Delta$$

in order for the cumulative $F(COC^*)$ CO_2 supply curve to make sense. If the CO_2 price sent from CCATS to IDM is less than the minimum *COC*, that is, if $COC^* \leq COCi + \Delta$, then no CO_2 is economically captured. If $COC^* \geq COCf + \Delta$, then all the CO_2 in that region is economical to capture.

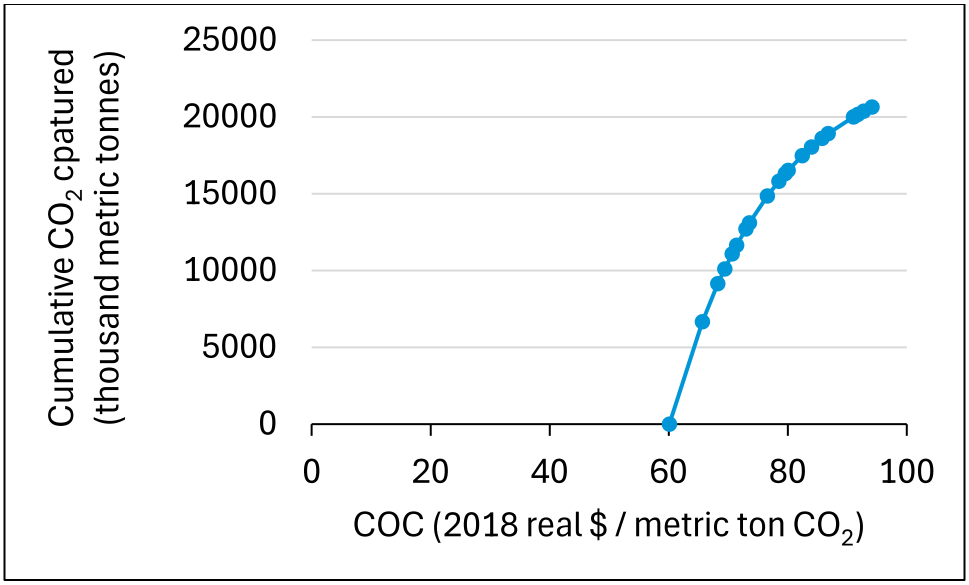
Examples of the unshifted and shifted cost curves (cumulative exponential distribution functions) using this methodology are shown below for census region 2:

Figure C-3. Census region 2 cumulative distribution/supply curve



Source: U.S. Energy Information Administration

Figure C-4. Census region 2 shifted cumulative distribution/supply curve

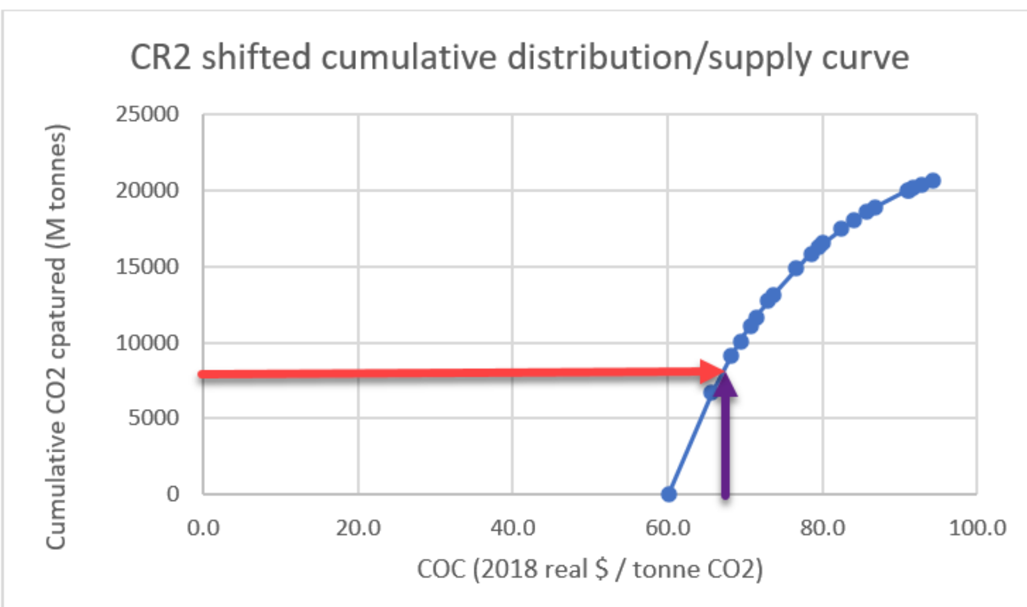


Source: U.S. Energy Information Administration

Importantly, both the “unshifted” and “shifted” curves possess the same curvature/form and both have the same ultimate cumulative supply of CO_2 at their respective maximum *COC*s.

For a given CO_2 price, we can graphically see what level of CO_2 can be captured.

Figure C-5. Census region 2 shifted cumulative distribution/supply curve



Source: U.S. Energy Information Administration

In Figure C-5, we see that at a CO_2 price of about \$67/metric ton, roughly 7.5 million metric tons of CO_2 is economic to be captured (mathematically, using the cumulative CO_2 captured equation above, this means $F(\$67/tonne) = 7\ million\ metric\ tons$).

Capping the accumulated CCS equipment over the projection period

If the parameter techpotenCCS(inumreg) is small, then as described earlier only a small fraction of the economically viable new CCS retrofit equipment in any given year will be installed. However, even so, every year that more CCS equipment is installed means that less is available to be potentially retrofitted the next year. To simulate this decline in available cement capacity which could be retrofitted as more and more cement capacity is retrofitted, we can scale down the total available CO_2 available for new retrofits by multiplying the normalization factor normCCS(inumreg) with a scaling factor that reduces the available potential cement plant capacity that can be outfitted new retrofits by an amount equivalent to the previously installed CCS retrofit capacity. Thus, for instance if in 2027 3% of existing cement capacity was outfitted with CCS retrofits, then in 2028 the cumulative CO_2 supply curve would be reduced by 3%, that is, the potential cement capacity available for retrofits would be reduced by 3% (and only 97% of the original maximum available capacity for CCS retrofitting would be available). This also ensures that the CCS implementation can never exceed the amount of available cement capacity (recall that we do not allow new cement capacity to be retrofitted with CCS equipment).

Mechanically, in ind.f, this works as follows. The variable maxpossibleCO2(inumreg) is the maximum theoretical CCS capacity (in thousand metric tons) that can be installed which is dimensioned only by region not by year (this value is independent of year because we assume currently in the IDM that only existing cement kilns can be retrofitted with CCS equipment). It also does not depend on any shift in the curve in a given year. The variable testtotalCCS(inumreg) is the accumulated CCS capacity through the current projection year *curcalyr*. Thus in the following projection year *curcalyr + 1*, the percentage of capacity that has not yet been retrofitted is:

[maxpossibleCO2(inumreg) – testtotalCCS(inumreg)] / maxpossibleCO2(inumreg)

So as testtotalCCS(inumreg) approaches maxpossibleCO2(inumreg), the above ratio (called CCSretrofitscalar(idummy,curiyr) in the IDM code) approaches zero. This ratio is multiplied in the ind.f code by the technical potential of a given region in the following projection year to make sure the cumulative added CCS retrofit capacity for all existing cement plants in *curcalyr + 1* never exceeds to total possible capacity.

Summary of mathematical formulation for setting up the "shiftable" cumulative CO_2 supply curve:

1. Gather plant-level data (COC in \$/metric ton and the corresponding amount of CO_2 that is "capturable") for a given region.
2. Fit data (amount of CO_2 captured versus COC) to a (hopefully) exponential curve using EXCEL regression tool using this procedure:
    a. Assume a functional form of $CO_2\ captured = a * exp\ (b * COC)$
    b. $ln(CO_2\ captured) = ln(a) + b * COC$

c. Do a linear regression of $ln(CO_2\ captured)$ versus *COC* to get $y\ intercept = ln\ (a)$ and $slope = b$

d. The fitted exponential curve that provides the amount of CO_2 captured at a particular COC (as opposed to a cumulative amount of CO_2 captured) is:

$$CO_2\ captured = exp(y\ intercept) * exp(slope * COC)$$

3. Create the cumulative supply curve by integrating the exponential fit curve above:

$$F(COC) = N\ \frac{\exp(y\ intercept)}{slope}[\exp(slope * COC) - \exp(slope * COCi)]$$

where this provides the amount of *F* of CO_2 that can be captured as a function of the *COC.*

4. This cumulative supply cure can be dynamically shifted each model year (for example, as the fuel prices change each year) to give

$$F(COC^*) = N\ \frac{exp[y\ intercept(shifted)]}{slope}[exp(slope * \{COC^*\}) - exp(slope * [COC_i + \Delta])]$$

Thus at a particular CO_2 price, we just assume COC^* = CO_2 price to get the total possible CO_2 capturable with retrofit equipment. This is the “economic potential”.

5. Adjust $F(COC^*)$ (the “economic potential”) by a “technical potential” factor [techpotenCCS(inumreg)] so that each year only a fraction of the economically viable plant capacity for CCS retrofits is actually retrofitted.

<u>Setting pre-processing parameters in the input file</u>:

Below is the itemization of parameters pre-processed computed (based on 2018 NETL data for cement CCS retrofits) in the IDM input file ironstlx.xlsx.

Table C-4. Pre-processed parameters for cement CCS modeling

Variable name	Description
CCSstartyear	start year for CCS (based on knowledge of cement facilities and when they are likely to start retrofitting CO_2 capture equipment—set at 2028 for AEO2025)
techpotenCCS(region)	technical potential (what percentage of plants with economic retrofit CO_2 capture can be built in a given projection year)
slopeCCS(region)	slope of fitted exponential regression
yinterceptCCS(region)	y-intercept of fitted exponential regression
normCCS(region)	normalization constant
halfofintCCS(region)	half of the integral of the fitted exponential distribution
lowestCCS(region)	lowest kiln COC (2018 dollars)
highestCCS(region)	highest kiln COC (2018 dollars)
meanofdistCCS(region)	mean of fitted exponential distribution
OplusMfixCCS(region)	fixed O&M cost (2018 dollars)
OplusMvarCCS(region)	non-fuel variable O&M cost (2018 dollars)
BaseCapCCS(region)	base capital cost (2018 dollars)
NatGasUseCCS	NETL-derived cement retrofit CCS natural gas fuel use (5.08 MMBtu/metric ton CO_2)
ElectricUseCCS	NETL-derived cement retrofit CCS purchased electricity use (0.509 MMBtu / metric ton CO_2)

Variable name	Description
PPCCS(region)	Payback Period (in years)

Source: U.S. Energy Information Administration

Programming/algorithmic details

The relevant variables in the integration with CCATS are shown below.

1. CST_CMT_INV(inumreg,MNUMYR): capital cost CCS (1987 dollars/metric ton CO_2:
2. CST_CMT_OM: O&M cost CCS (1987 dollars/metric ton CO_2): includes fuel costs
3. SUP_CMT_45Q(inumreg,MNUMYR): CO_2 volume captured from cement plants that are 45Q eligible (metric tons CO_2)
4. SUP_CMT_NTC(inumreg,MNUMYR): CO_2 volume captured from cement plants assuming no tax credit (metric tons CO_2)
5. CO2_PRC_REG_45Q(inumreg,MNUMYR): CO_2 price output after optimization for 45Q eligible CO_2, (1987 dollars/metric ton CO_2)
6. CO2_PRC_REG_NTC(inumreg,MNUMYR): CO_2 price output after optimization, no tax credit, (1987 dollars/metric ton CO_2)

Variables **1–4** are sent from the IDM to CCATS; **5–6** are sent from CCATS to IDM.

In any given projection year, the amount of new economically capturable CO_2 from new retrofits on cement kilns is computed as noted above and stored in the variable economicalCCS(inumreg, MNUMYR), which is expressed in thousand metric tons CO_2 captured. Since in reality not all new builds will be possible, the above new retrofit builds are tempered by a penetration rate techpotenCCS(inumreg), which is between 0.0 and 1.0 and is read in from ironstlx.xlsx using the equation

economicalCCS(idummy,curiyr) = economicalCCS(idummy,curiyr) * techpotenCCS(idummy)

where idummy is the census region index (1–4) and curiyr is the year index (1 = 1990). Note that no matter when the CCS retrofit equipment is assumed to be built, if the CO_2 price CO2_PRC_REG_45Q(inumreg,MNUMYR) is less than the lowest (shifted) limit of a given region's COC, then there will be no capture at all.

Capital Cost Adder (CapAdderCCS(MNUMCR,MNUMYR))

The CapAdderCCS is computed endogenously based on the current build year's interest rate (NEMS's 10-year Treasury Note) for years > LastSTEOYr as it is only then that CCATS allows for CO_2 pipeline builds.

To compute CapAdderCCS, the capital recovery factor (CRF) for the current year (curiyr) is computed as before, only the interest rate *i* is first computed based on https://www.investopedia.com/ask/answers/032515/what-difference-between-real-and-nominal-interest-rates.asp Fisher Effect formula:

Real Interest Rate = Nominal Interest Rate – Projected rate of Inflation

i = MC_RMTCM10Y(curiyr) - ((MC_CPI(11,curiyr) / MC_CPI(11,curiyr-1)) - 1) * 100

The *CRF* is then computed from this new *i* every model year, where *n* in the above *CRF* equation is the payback period PPCCS(MNUMCR) (which is set as a fixed input parameter in ironstl.xlsx).

CapAdderCCS in a given model year is then

CapAdderCCS(Census Region, curiyr) = BaseCapCCS(Census Region) * [(*CRF* / 0.0623) – 1.0]

which is dimensioned by year because of changing endogenous interest rates. [51] Note that the longer the payback period PPCCS(MNUMCR) parameter is, the smaller CapAdderCCS is. Recall that in the previous section "Capital Cost Adder (CapAdderCCS(MNUMYR)): static version" when PPCCS(MNUMCR) is set to be 30 years in the ironstl.xlsx input file, then *CRF* = 0.0623 as it must since the 0.0623 value is based on the "default" settings from the NETL data base which assumes a 4.63% interest rate and a 30-year payback period. In this "dynamic version" the endogenous NEMS Treasury rate of course varies, but obviously the longer the payback period, the smaller CapAdderCCS is, and could even be negative if for some model years if the Treasury rate goes below the assumed NETL default rate of 4.63%.

Within the ind.f code, adopting this "dynamic" CRF will necessitate removing the CapAdderCCS variable from the ironstlx.xlsx input file as it will no longer be read in by the ind.f code. Moreover, it will need to be defined/dimensioned differently, using now both region and time (year) dimensions.

Payback period approach option

Rather than looking at the economics of CCS on a yearly basis in the current model year, we can use foresight with a pre-determined payback period *PP* (measured in years) to see how much CCS retrofit capacity should be built. Using this approach, in any given year the amount of cement kiln capacity built must be able to reap a profit in *PP* years or otherwise it will not be built. This requires a degree of foresight. Over the duration of the *PP*, the yearly economic comparison of costs vs. price must reap a profit to stay functional.

Recall that the cost/supply curve for determining the economically available CO_2 for installing CCS equipment and also the economically amount of CO_2 that can be captured once the CCS equipment is installed is given by

[51] To derive this formula for CapAdderCCS, we start with the basic "Breakeven Analysis" equation (see page 19 of https://www.eia.gov/outlooks/documentation/workshops/pdf/tea_guide_071015_draft.pdf): Amortized Capital Cost (ACC) = Total Project Cost (TPC) * Capital Recovery Factor (CRF). Let the NETL 30-year payback period with 4.63% interest ACC_i and the cost associated with a more realistic payback period (for example, 12 years, which is the duration of the 45Q tax credit for sequestering carbon as expanded and spelled out in the Inflation Reduction Act) ACC_f. So ACC_i = TPC * CRF_i and ACC_f = TPC * CRF_f. Then solving for TPC in both equations and setting them equal to each other we get $ACC_f = ACC_i * CRF_f / CRF_i$. But according to the formulation of the *COC* curve shift (see adjusting the "average" COC in the supply curve section), we need an *additive* factor (CapAdderCCS), not a multiplicative factor, to adjust the capital cost BaseCapCCS assuming another interest rate (the base capital costs by NETL assume a 4.63% interest rate). Thus, we say $ACC_f = ACC_i + x$, and then equating the two forms for ACC_f together, we get $x = ACC_i * (CRF_f / CRF_i) - ACC_i$, where ACC_i = BaseCapCCS and x = CapAdderCCS.

$$F(COC^*) = N \frac{\exp[y\ intercept(shifted)]}{slope}[\exp(slope * \{COC^*\}) - \exp(slope * [COC_i + \Delta])]$$

where COC^* is the CO_2 price sent from CCATS via the variable CO2_PRC_REG_45Q(inumreg,MNUMYR) or CO2_PRC_REG_NTC(inumreg,MNUMYR). For the above equations to be relevant COC^* must fall in the range

$$COC_i + \Delta \leq COC^* \leq COC_f + \Delta$$

Recall also that the Δ here is the shift from the base cost assumptions (for example, the year-to-year change in fuel prices to operate the CCS equipment). Finally, recall that if COC^* is less than $COC_i + \Delta$ then no CO_2 can be captured economically (and no CCS equipment can be built economically), and if COC^* is greater than $COC_f + \Delta$ then all CO_2 can (theoretically) be captured and all plants (theoretically) can economically have CCS equipment installed.

Again, in the simplistic approach described in the previous section where the capital costs are amortized over the (unrealistic) period of 30 years, the CO_2 price provided by CCATS in any given year (COC^*) is the marginal cost of retrofitting and capturing CO_2 that year. In other words,, COC^* is the cost of capture for the marginal kiln producer of CO_2. This means that the marginal producer of CO_2 just breaks even on the shifted CO_2 cost curve at the CCATS-provided CO_2 price of COC^* (which we plug into the above equation to get the marginal production of CO_2 from new retrofits), while all the other kilns who can retrofit for a cost below COC^* will make a finite profit. There is no foresight in this approach since the payback period (amortization period) is well beyond the projection period. Thus, again, in the above approach the CCS retrofit economics are determined solely by the marginal *COC* relative to the CO_2 price in any given year, with the capital cost part of the *COC* being the amortized 30-year period.

In order employ a more realistic payback period *PP* (which ideally would be no longer than the 45Q tax credit duration of 12 years), we would then insist on profitability (on average) over the entire *PP*. Since one can assume that if the marginal capturer/producer of CO_2 is profitable over *PP* then all less-expensive producers below it are also profitable, we can just focus on the marginal producer and its *COC*.

To do this, we simply need to get the average $F(COC^*)$ at a given year over the payback period:

$$F_{avg}(COC^*) = \frac{N}{PP} \sum_{n=current\ year}^{current\ year+PP-1} \frac{\exp[y\ intercept(shifted)]}{slope}[\exp(slope * COC(n)) - \exp(slope * [COC_i + \Delta(n)])]$$

Here, $\Delta(n)$ encompasses any and all variable costs (which for the current rendition of the cementCCS submodule in the IDM are just the fuel costs). Note that we must use future values of fuel and other variable costs through $\Delta(n)$ (foresight) in order to implement the above equation.

Note that when *PP* = 1 the above equation reduces to the previous formulation for determining $F(COC^{*})$, but this does not mean that the payback period was one year; it just means that no foresight was done. Note also that we also allow the future years' CCATS CO_2 price in the above equation in addition to the variable costs.

In the IDM code, the payback period is user-determined and read in from the cement tab of the ironstlx.xlsx input file as PPCCS(MNUMCR). In the AEO2025, all four census region values for PPCCS(MNUMCR) were 12 years, the time horizon of the 45Q tax credit as defined by the Inflation Reduction Act.

Incorporating IDP grants into IDM/CCATS AEO2025 projections

As of the end of 2024, only two cement plants had been awarded grants pertaining to CCS retrofit installation under the U.S. Department of Energy's Industrial Demonstrations Program (IDP).

The first was the Heidelberg cement plant in Mitchell, Indiana. This plant would produce 2.4 million metric tons/year with a standard 95% capture rate of CO_2. This means that the CCS retrofit capacity for this plant is 2.4 million metric tons cement * (0.922 metric tons CO_2/metric ton cement) * 0.95 = 2.1 million metric tons CO_2 (per year) initial capacity.

We estimated that the funding for the project extends through 2030 (the first two phases of the Heidelberg project were not directly related to the CCS installation and were not to be completed until 2026, so the timeline of the CCS completion was uncertain).

Applying the IDP grant for the Heidelberg Mitchell plant goes as follows (and other grants could be applied similarly). According to the NETL CCRD for potential cement plant CCS retrofits, in census region 2 there is 21.5 million metric tons/year of CO_2 to be potentially captured. The 2.1 million metric tons of CO_2 that Heidelberg proposes to remove is nearly 10% of capturable cement CO_2 in census region 2. A $500 million grant for that emission level of 2.1 million metric tons/year equates to $500,000,000/21,500,000 metric tons = $23.30/metric ton in savings (presumably targeting the capital costs). Because the Heidelberg kiln in Mitchell, Indiana represents 10% of the total census region 2 cement emissions, the overall capital cost savings is $23.30/metric ton * (2.1 / 21.5) = $2.30/metric ton. This cost reduction is then applied to the BaseCapCCS parameter in the ironstlx.xlsx input file: 17 – 2.3 = $14.70/metric ton. Note that this capital cost reduction is an optimistic estimate because it assumes that the majority of the $500 million awarded as a cost share from the OCED program is going towards actual funding for the CCS retrofit. Thus, in incorporating this decline in census region 2 capital cost, we are assuming that the project will be completed in all phases and that most of the funding is in fact for the retrofit installation.

Another consideration regarding the Mitchell IDP grant is the operational start year of the CCS equipment. Based on what project details available at the end of 2024, the actual CCS installation was not mentioned in the timeline, while the first two phases would have extended into 2026. Thus we assumed that the CCS retrofit would not be fully operational before 2028, which can be modeled through the start year parameter CCSstartyear in the ironstlx.xlsx input file. Since no other commercial

CCS retrofits on cement kilns had been announced, the change of CCSstartyear to 2028 (which in the current model represents the start year for all census regions) seemed appropriate.

The second IDP CCS cement retrofit project is the Lebec Net Zero project in California. Like the Heidelberg Mitchell plant project, this award matched company financing up to $500 million. Also like the Mitchell cement CCS retrofit project, Lebec would have been awarded in phases as sequential projects were completed. However, an unknown amount of the funding would have gone to conversion of the plant from using limestone to calcined clay. Thus, the accuracy of putting cost decline value on the CCS retrofit project itself is more difficult to determine, so this funding was not considered for the AEO2025.

Note on general cost considerations for cement retrofit CCS equipment:

Costs vary widely for cement CCS and CCUS. The IEA purports a range of $60 - $120/metric ton CO_2 captured (2019 dollars) https://www.iea.org/commentaries/is-carbon-capture-too-expensive. The range of NETL costs (which are used for the IDM in AEO2025) show a large gap in retrofit total costs even between their own studies, namely their 2023 cement retrofit study (https://www.osti.gov/servlets/purl/1970135) and their 2022 study (https://www.netl.doe.gov/projects/files/CostofCapturingCO2fromIndustrialSources_071522.pdf). Even accounting for the deflationary factor between years 2022 and 2018 (14%), the 2022 study assumes a lot lower costs than the 2023 cement retrofit study (note that the 2023 cement retrofit study has the same cost breakout detail as the 2022 study).

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