Assumptions to the Annual Energy Outlook 2023

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Industrial Demand Module

The National Energy Modeling System's (NEMS) Industrial Demand Module (IDM) estimates U.S. energy consumption by energy source (fuels and feedstocks) in the *Annual Energy Outlook* (AEO) for 15 manufacturing and 6 nonmanufacturing industries. The IDM subdivides manufacturing industries further into energy-intensive manufacturing industries and non-energy-intensive manufacturing industries (Table 1). The IDM models manufacturing industries through either a detailed process-flow or an end-use accounting procedure. The IDM models the nonmanufacturing industries with less detail because the processes are simpler and fewer data are available. The petroleum refining industry is not included in the IDM because the NEMS Liquid Fuels Market Module (LFMM) models it separately. The IDM calculates energy consumption for the four census regions (Table 2) and disaggregates regional energy consumption to the nine census divisions based on fixed shares from our State Energy Data System (SEDS). The IDM uses the latest published SEDS year (2020 for AEO2023) to determine these census division shares.[1] Overall, the IDM runs from model year 2018 through 2050.

Table 1. Industry categories and North American Industry Classification System (NAICS) codes

Energy-intensive manufacturing		Non-energy-intensive manufacturing		Nonmanufacturing	
Food products	311	Metal-based durables industries		Agriculture: crop production	111
Paper and allied products	322	Fabricated metal products	332	Other agricultural production	112, 113, 115
Bulk chemicals group[a]		Machinery	333	Coal mining	2121
Inorganic	325120, 325180	Computer and electronic products	334	Oil and natural gas extraction	211
Organic	325110, 325193, 325194, 325199	Electrical equipment and appliances	335	Metal and other non-metallic mining	2122-2123
Resins	325211, 325212, 325220	Transportation equipment	336	Construction	23
Agricultural chemicals	325311, 325312	Wood products	321		
Glass and glass products	327211, 327212, 327213, 327215, 327993	Plastic and rubber products	326		
Cement and lime	327310, 327410	Balance of manufacturing	312–316, 323, 3254–3256, 3259, 3271, 327320, 327330, 327390, 327420, 3279 (except 327993), 3314, 3315, 337, 339		

Iron and steel	331110, 3312, 324199[b]
Aluminum	3313

Data source: U.S. Energy Information Administration, *Annual Energy Outlook 2022* (AEO2022); U.S. Department of Commerce; U.S. Census Bureau; and North American Industry Classification System (2017)—United States (Washington, DC, 2017)

[a] The AEO2022 reports bulk chemicals energy consumption as an aggregate.

[b] NAICS 324199 contains merchant coke ovens, which the AEO2022 considers part of the iron and steel industry.

Table 2. Census regions, census divisions, and states

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

Data source: U.S. Census Bureau, *2010 Census Regions and Divisions of the United States*—United States (Washington, DC, 2021)

The IDM models most industries as three separate but interrelated components:

- Process and assembly (PA)
- Buildings (BLD)
- Boiler, steam, and cogeneration (BSC)

The IDM calculates the PA component by end-use for all but five manufacturing industries. We calculate these five industries by production process (process flow):

- Paper
- Glass
- Cement and lime
- Iron and steel
- Aluminum

The BSC component satisfies the steam demand from the PA and BLD components. In some industries, the PA component produces byproducts that the BSC component consumes. The iron and steel, paper, and aluminum industries determine boiler and combined-heat-and-power (CHP) fuel use in the PA step.

The IDM base year is currently 2018, which is the year of the latest available *Manufacturing Energy Consumption Survey* (MECS).[2] Our Office of Energy Statistics conducts the MECS every four years, and we update the IDM base year when a new MECS becomes available.

The IDM does not model petroleum refining (NAICS 32411), which the LFMM models in detail, but the manufacturing total does contain the projected petroleum refining energy consumption. In addition, projections of lease and plant fuel, energy used to liquefy natural gas, and fuels consumed in cogeneration in the oil and natural gas extraction industry (NAICS 211) are calculated in modules other than the IDM.

Key assumptions—manufacturing

The IDM primarily uses a bottom-up modeling approach. An energy accounting framework traces energy flows from fuels to an industry's output. The IDM depicts the manufacturing industries, except for petroleum refining, with either a detailed process-flow or an end-use approach. Generally, industries with uniform products use a process-flow approach, and those with varied products use an end-use approach.

Five industries use a process-flow approach:

- Paper
- Glass
- Cement and lime
- Iron and steel
- Aluminum

Other industries use an end-use approach:

- Food
- Bulk chemicals
- The five metal-based durables industries (transportation equipment, machinery, computers, electrical equipment, and fabricated metals)
- Wood products
- Plastic and rubber products
- Balance of manufacturing (includes beverages, tobacco, furniture, other primary metals, pharmaceuticals, paints, soaps cleaning products, textiles, and other miscellaneous products)

Process and assembly component for end-use submodules

Most manufacturing industries are modeled as end-use industries. End-use industries usually have a number of different products, which makes specifying a manageable number of process steps impossible. As a result, we model end-use industry energy consumption by general industrial processes, such as heating, cooling, or machine drive, instead of by specific process steps. The IDM models end-use process and assembly (PA) energy consumption at the census region level and aggregates to the national level.

For manufacturing industries modeled using the end-use approach, the PA component models each major production end use through an evolving energy intensity, or unit energy consumption (UEC), defined as the amount of energy required to produce one dollar worth of output for a given process.

For end-use industries, the IDM establishes baseline UECs in the base year (currently 2018). The IDM calculates base year UECs for each manufacturing end-use process and each region by dividing MECS energy consumption data by industrial shipments from the NEMS Macroeconomic Analysis Module (MAM).

The IDM characterizes each major process end use in later years by using technology possibility curves (TPCs) to estimate UECs (Table 3). A TPC represents the assumed average annual rate of change of energy intensity in an energy end use (for example, natural gas-fired heating). Each TPC for new and existing capacity varies by industry, process, vintage, and region. We developed these assumed rates using professional engineering judgments about energy characteristics, years of availability, and market adoption rates for new process technologies. Table 3 only shows median intensities for end use and fuel pairs, but the IDM calculates a unique TPC for each industry, end -use, vintage, and region.

Table 3. Median unit energy consumptions (UECs) and relative energy intensities (REIs)

End use	Fuel	UEC 2018 (trillion British thermal units per billion 2012$ of shipments)	REI 2050 existing	REI 2018 new	REI 2050 new
Heat	Natural gas	0.171	0.844	0.965	0.815
Heat	Electricity	0.026	0.919	0.984	0.895
Heat	Steam	0.408	0.844	0.964	0.812
Refrigeration	Electricity	0.049	0.911	0.977	0.890
Machine drive	Natural gas	0.021	0.945	0.997	0.923
Machine drive	Electricity	0.198	0.917	0.984	0.896
Electrochemical processes	Electricity	0.040	0.940	0.993	0.924
Other	Natural gas	0.022	0.837	0.945	0.833
Other	Electricity	0.008	0.911	0.982	0.892

Data source: U.S. Energy Information Administration, *Manufacturing Energy Consumption Survey 2018* (Washington, DC, August 2021)

Notes: This table shows median UEC values for existing equipment in 2018 and REIs, illustrating the magnitude of UECs and REI values. We estimate UECs and REIs for each industry, region, and end use. The medians represent the median for a particular fuel and end use among all industries with that end use and fuel. We estimate the medians independently.

UEC 2018 is the energy consumption for region, industry, and end use divided by regional shipments of that industry.
REI 2050 existing is the ratio of 2050 energy intensity to 2018 energy intensity for existing facilities in the Reference case.
REI 2018 new is the ratio of energy intensity in 2018 for new, state-of-the-art facilities to energy intensity in 2018 for existing facilities in the Reference case.
REI 2050 new is the ratio of energy intensity in 2050 for new, state-of-the-art facilities to energy intensity in 2018 for existing facilities in the Reference case.

To simulate technological progress and adoption of more energy-efficient technologies, the IDM adjusts each UEC every projection year, based on the assumed TPC for each end-use step. We derive a TPC from assumptions about the relative energy intensities of productive capacity by vintage (new capacity relative to existing stock in a given year) or over time (new or surviving capacity in 2050 relative to the 2018 stock). Over time, each UEC for new capacity changes, and the TPC is the rate of change. The IDM also assumes every UEC of the surviving 2018 capital stock changes over time because of retrofitting but not as rapidly as for new capital stock.

REIs and TPCs are general assumptions we make about new technology adoption in the manufacturing industry and the associated change in energy consumption without characterizing individual technologies. This approach also assumes that energy consumption at industrial plants will change when owners do any of the following:

- Replace old equipment with new, more efficient equipment
- Add new capacity
- Add new products
- Upgrade energy management practices

We cannot directly attribute increased efficiency to technology choice because these industries are complex. Instead, the IDM uses the REIs and TPCs to characterize intensity trends for bundles of technologies available for end-use industries. TPC and REI calculations for industries can either decline at a fixed percentage or can vary over time, reflecting how changes in fuel price over time might affect the rates at which energy intensities decline.

The module distinguishes each UEC by three vintages of capital stock. We base the energy consumption the assumption that new vintage stock will consist of state-of-the-art technologies that have different efficiencies than the existing capacity. As a result, the energy required to produce a unit of output using new capacity is often less than what the existing capacity requires. The old vintage capacity consists of includes capacity that exists in the IDM base year and continues to operate after adjusting for assumed retirements each year (Table 4). In a given projection year, the IDM adds new production capacity to ensure that sufficient remaining and new capacity is available to meet an industry's regional output as determined in the MAM. Middle vintage capacity is capacity added after the base year through the year before the current projection year.

Table 4. Annual retirement rates for end-use industries

Industry	Retirement rate (x100)	Industry	Retirement rate (x100)
Food products	1.7	Wood products	1.3
Bulk chemicals	1.7	Plastics and rubber products	1.3
Metal-based durables	1.3	Balance of manufacturing	1.3

Data source: SAIC's Industrial Demand Module base year update with *Manufacturing Energy Consumption Survey 2006* data and unpublished data prepared for our Office of Integrated Analysis and Forecasting (Washington, DC, August 2010)

Electric motor stock submodule

When calculating energy consumed in the machine-drive end use, the IDM uses an end-use electric motor technology choice submodule instead of a UEC and TPC. The IDM calculates machine-drive electricity consumption using a motor stock submodule for seven industries:[3]

- Bulk chemicals industry
- Food industry

- Metal-based durables industries
- Wood
- Plastics
- Rubber products
- Balance of manufacturing

The module modifies the beginning stock of electric motors during the projection period. The submodule adds electric motors each year to accommodate growth in shipments for each industry or industry group as motors are retired and replaced and as failed motors are rewound. When an old motor fails, the submodule determines whether it would be more economical to repair the motor or replace it. To add a new motor, either to accommodate growth or replace a retiring motor, it must meet the minimum efficiency standard (Table 5). The module assumes all replacement motors are premium, high-efficiency motors because of current efficiency regulations.

Table 5. Cost and performance parameters for industrial motor choice submodule

Industry and horsepower (hp) range	Average efficiency	Replacement motor efficiency	Rewind cost (2002$)	Replacement cost (2002$)
Food				
1–5 hp	81.3	89.5	$230	$442
6–20 hp	87.1	93.0	$427	$1,047
21–50 hp	90.1	94.5	$665	$1,889
51–100 hp	92.7	95.4	$1,258	$5,398
101–200 hp	93.5	96.2	$2,231	$10,400
201–500 hp	93.8	96.2	$4,363	$20,942
More than 500 hp	93.0	96.2	$5,726	$28,115
Bulk chemicals				
1–5 hp	82.0	89.5	$230	$442
6–20 hp	87.4	93.0	$427	$1,047
21–50 hp	90.4	94.5	$665	$1,889
51–100 hp	92.4	95.4	$1,258	$5,398
101–200 hp	93.5	96.2	$2,231	$10,400
201–500 hp	93.3	96.2	$4,363	$20,942
More than 500 hp	93.2	96.2	$57,26	$28,115
Metal-based durables[a]				
1–5 hp	82.2	89.5	$230	$442
6–20 hp	87.3	93.0	$427	$1,047
21–50 hp	90.1	94.5	$665	$1,889
51–100 hp	92.4	95.4	$1,258	$5,398
101–200 hp	93.5	96.2	$2,231	$10,400
201–500 hp	94.5	96.2	$4,363	$20,942
More than 500 hp	94.4	96.2	$5,726	$28,115

Wood, plastic, and balance of manufacturing				
1–5 hp	81.8	89.5	$230	$442
6–20 hp	86.6	93.0	$427	$1,047
21–50 hp	89.9	94.5	$665	$1,889
51–100 hp	92.1	95.4	$1,258	$5,398
101–200 hp	93.2	96.2	$2,231	$10,400
201–500 hp	93.1	96.2	$4,363	$20,942
More than 500 hp	93.1	96.2	$5,726	$28,115

Data source: U.S. Department of Energy, *United States Industrial Electric Motor Systems Market Opportunities Assessment* (Burlington, MA, December 1998) and MotorMaster+ 4.0 software database, 2007
Note: The efficiencies in this table are operating efficiencies based on average part-loads. Because the average part-load is not the same for all industries, the efficiencies for the different motor sizes vary across industries.
[a] The metal-based durables group includes five industries that are modeled separately: fabricated metals, machinery, computers and electronics, electrical equipment, and transportation equipment.

Petrochemical feedstock requirement

The IDM estimates feedstock requirements for the major petrochemical olefin products, such as ethylene, propylene, and butadiene. The primary feedstocks used to produce the olefins are hydrocarbon gas liquids (HGLs) (ethane, propane, and butanes) and heavier, oil-derived petrochemical feedstocks (naphtha and other oils). These feedstocks are converted to olefins, primarily ethylene, in a chemical process known as *cracking*. The IDM also models demand for natural gas feedstock to produce methanol, ammonia, hydrogen, and other chemical products. Biomass is a potential raw material source for chemicals, but the module assumes biomass-based capacity is unavailable during the projection period because of economic barriers. The type of feedstock determines the energy requirements for heat and power to produce the chemicals, as well as the product yield.

We base historical HGL and heavy petrochemical feedstock consumption on SEDS data, and we base 2021–23 feedstock consumption on *Short-Term Energy Outlook* forecasts and external data sources. From 2024 on, the sum of HGLs and heavy feedstock consumption changes based on shipments of resins, synthetic rubber, and fibers (the current module does not incorporate any additional plastic or chemical recycling capacity). We assume all new olefin production capacity in the United States is light-feedstock-based. However, under certain price conditions, some light-feedstock consumption is allowed to switch over to heavy-feedstock consumption. This ability represents how certain cracking facilities can switch between cracking HGLs and cracking heavy feedstock.

This light-heavy feedstock switching is represented in the IDM as switching between using ethane (light) and naphtha (heavy) feedstocks in ethylene production (ethylene is the desired olefin product). Ethane-naphtha switching depends on the relative price of each feedstock (derived from linear regressions of historical chemical price data and the West Texas Intermediate crude oil price), the chemical cracking efficiencies of each feedstock (shown in Table 6), and the prices of the coproducts from the respective cracking reactions. The IDM calculates the net feedstock cost needed to produce one metric ton of ethylene from ethane; it subtracts the value of the side products produced from the ethane cracking from the cost of the ethane consumed to get the net feedstock cost to produce ethylene from ethane. The IDM calculates the same value for naphtha feedstock by subtracting the value of the side products yielded from producing one metric ton of ethylene from naphtha from the cost of the naphtha feedstock consumed. We compare the net costs of each feedstock, and we consider the feedstock with the lower net feedstock cost to be more economical. We assume the differences in process and in capital costs are negligible.

Table 6. Chemical mass yields for cracking ethane and naphtha

metric tons of product per metric ton of feedstock

Products	Ethane	Naphtha
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 and 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

Data source: American Chemistry Council, *Ethylene Product Stewardship Manual*, December 2004

The amount of capacity that can switch between ethane and naphtha is based on a few assumptions. First, we assume the baseline naphtha feedstock demand is constant from 2024 on, equal to 90% of 2019 naphtha feedstock consumption, or about 550 trillion British thermal units (TBtu). All of this capacity is in the West South Central Census Division. Second, some cracking capacity can quickly switch between cracking ethane and naphtha, depending on the relative net feedstock costs. The baseline *quick-flex* capacity is the amount of ethylene produced from naphtha in 2011 minus the ethylene produced from the nonflexible (naphtha-only) capacity, or about 2.605 million metric tons of ethylene. Quick-flex capacity is all located in the West South Central Division.

In a given year where either ethane or naphtha is more economical, 50% of existing flex capacity (after capacity additions) will change to the most economical feedstock if that feedstock is not already being used in 100% of the quick-flex capacity. Some flexible capacity, which cracks only ethane in the base year, can switch more slowly. Given a sustained price signal where the net feedstock costs for ethane are higher than the net feedstock costs for naphtha for three consecutive years, some of the *slow-flex* capacity will switch over to quick-flex capacity after a construction period of two more years. This switch represents cracking facilities that need substantial investment to be able to crack naphtha. The baseline slow-flex capacity is the amount of ethylene produced from naphtha in 2004 minus the amount of ethylene produced from naphtha in 2011, or about 5.513 million metric tons of ethylene. Slow-flex capacity is converted to quick-flex capacity in increments of 1.102 million metric tons of ethylene capacity. We assume no new slow-flex capacity will be built.

For 2019–23, we use an external, analyst-based natural gas feedstock forecast based on project-level methanol and ammonia/urea capacity estimates, as well as changes in shipments in selected sectors. We similarly use ethylene cracker project data for both the HGL (light) and naphtha (heavy) feedstock forecast for 2022–23. In addition, the IDM breaks down HGL feedstocks into components (ethane, propane, propylene, butanes, and natural gasoline). The IDM holds propylene consumption constant at about 300,000 barrels per day throughout the projection period, close to current U.S. refinery propylene production levels.

We set baseline feedstock intensities based on the 2018 MECS. For chemical feedstocks, intensity does not change over time: the IDM assumes every feedstock TPC is zero. Unlike most other processes in manufacturing PA components, chemical yields follow basic chemical stoichiometry that allows for specific yields under set conditions of pressure and temperature.

Process and assembly component for process-flow submodules

The energy-intensive manufacturing industries modeled using a process-flow approach use a suite of detailed technology choices for each process flow. Instead of setting the energy intensity for each process and end use to evolve according to a TPC, the process-flow submodules use technology choice for each process flow. We derive technology characteristics (for example, expenditures, energy intensities, and utility needs) from the Consolidated Impacts Modeling System (CIMS) database that the Pacific Northwest National Laboratory prepares. These characteristics define the energy requirements for each technology.[4] Depending on the industry, we calibrate these data using inputs from the U.S. Geological Survey (USGS) of the U.S. Department of the Interior, the Portland Cement Association, and our latest MECS.[5,6]

The process-flow submodules calculate surviving capacity based on retirement and needed capacity, which, in turn, is based on shipments and surviving capacity. The IDM assumes that baseline capacity (as of 2018) will retire at a linear rate over a fixed period (20 years) and that incremental, or added, capacity will retire according to a logistic survival function (with a maximum lifespan of 30 years). An analyst can adjust parameters to obtain the exact shape of the logistic S-curve. We obtained equipment characteristics used for investment decisions (capital and operating costs, energy use, and emissions) for newly built equipment from the CIMS database. Each step of the process flow allows several technology choices whose fuel type and efficiency are known at the national level, based on available EIA data.

We benchmark the process-flow submodules to the 2018 MECS data for each fuel in each of the five process-flow industries. This process ensures a historically accurate fuel consumption baseline for the cement and lime, pulp and paper, aluminum, iron and steel, and glass industries modeled in the IDM. Steam coal and metallurgical (met) coal consumption are exceptions, which are benchmarked to base year data from our *Quarterly Coal Report*.[7]

Pulp and paper industry

The pulp and paper industry converts wood fiber to pulp, and then it manufactures paper, paperboard, and consumer products that are generally sold in the domestic marketplace. The industry produces a full line of paper and board products, as well as dried pulp, which it sells as a commodity product to domestic and international paper and board manufacturers. This industry includes several manufacturing steps and technologies:

- Wood preparation removes bark and chips logs into small pieces.
- Pulping removes fibrous cellulose in the wood from the surrounding lignin. Pulping can occur with a chemical or a mechanical process.
- Pulp washing with water removes the cooking chemicals and lignin from the fiber.
- Drying, liquor evaporation, effluent treatment, and other miscellaneous steps are part of the pulping process. Pulp is sent to a pressing section to squeeze out as much water as possible by mechanical means. The pulp is compressed between two rotating rolls, and the amount of water removed depends on the design and speed of the machine. When the pressed pulp leaves the pressing section, it has about a 65% moisture content. Various techniques for drying are available, and each has different energy consumption characteristics.
- Bleaching is required to produce white paper stock.

Paperboard, newsprint, coated paper, uncoated paper, and tissue paper are final products. Producing final products requires drying, finishing, and stock preparation.

Glass industry

In the glass industry submodule, each step of the glass-product processes modeled in the IDM allows several technology choices with known fuel type and efficiency, as well as other known operating characteristics.

For flat glass (NAICS 327211), the process steps consist of batch preparation, furnace, form and finish, and tempering. For pressed and blown glass (NAICS 327212), the process steps are preparation, furnace, form and finish, and fire polish. For glass containers (NAICS 327213), the process steps are preparation, furnaces, and form and finish. For fiberglass (mineral wool–NAICS 327993), the process steps are preparation, furnaces, and form and finish. We do not model the final category (glass from glass products–NAICS 327215) as a process flow industry with technology choices, but instead model it as an end-use industry that employs a UEC and TPC for each fuel to capture energy intensity changes over time.

The glass submodule uses several technologies. Not all of the technologies below are available to all processes:

- The preparation step (collection, grinding, and mixing raw materials, including recycled glass known as *cullet*) uses either a standard set of grinders and motors or advanced, computer-controlled grinders.

- The furnaces, which melt the glass, are air-fueled or oxy-fueled burners that use natural gas. Electric-boosting furnace technology is also available. Direct-electric (or Joule) heating is available for fiberglass production.

- The form and finish process applies to all glass products, and the technology options are high-pressure, natural gas-fired, computer-controlled technology, or basic technology.

- No technology choice exists for the tempering step (flat glass) or the polish step (blown glass). We added placeholders for more-efficient future technology choices, but their introduction into these processes was rather limited.

As with the other submodules, the technology options in each of these process steps evolves over time and depends on the relative cost of equipment, cost of fuel, and fuel efficiency. We added oxy-fueled burners as a retrofit to the burner technologies, and we determine their additive impact by using the relative price of natural gas and electricity.

Combined cement and lime industry

Each step in the cement process flow (raw material grinding, kiln, and finish grinding) can use several technologies, and we know each step's fuel types and efficiency at the national level because regional fuel breakouts are estimated using EIA data.

Cement has both dry- and wet-mill processes. Some technologies are available for both processes, but others are available for only one process. The technology choices within each group are:

- Raw materials grinding
  - Ball mill or roller mill
- Kilns (rotators)
  - Dry process only
    - Rotary long with preheat, precalcining, and computer control
    - Rotary preheat with high-efficiency cooler
    - Rotary preheat and precalcine with efficient cooler
  - Wet process only
    - Rotary wet standard with waste heat recovery boiler and cogeneration
- Kilns (burners)
  - Coal-fired: standard or efficient
  - Natural gas-fired: standard or efficient
  - Petroleum coke-fired: standard
  - Alternative fuel such as municipal solid waste (MSW): standard
- Finish grinding
  - Ball mill: standard or with high-efficiency separator
  - Roller mill: standard or with high-efficiency separator

The technology slate in each process step evolves over time and depends on the relative cost of equipment, cost of fuel, and fuel efficiency. The IDM assumes that wet-process kiln technology will retire permanently; the IDM can only add dry-process kilns can be added to replace retired wet kilns or to satisfy additional capacity demand.

We calibrate the IDM base-year technology slate for cement using data from the 2018 MECS, the CIMS database, the Portland Cement Association, and the USGS. The IDM assumes all new cement capacity, both for replacement and increased production, is dry cement capacity. It assumes existing wet capacity retires at a linear rate over 20 years with no replacement. It also assumes imported clinker, additives, and fly ash make up a constant percentage of the finished product and displace some domestic clinker production, which affects energy use.

The IDM estimates lime energy consumption separately from cement, but it presents them together as the consolidated cement and lime energy consumption. We use the same methods for cement drive energy consumption and technology evolution in the lime industry with different, industry-specific equipment choices.

Iron and steel industry

The iron and steel industry includes several major process steps:

- Coke production
- Iron production
- Steel production
- Steel casting
- Steel forming

Steel manufacturing plants are either integrated or nonintegrated. The classification depends on the number of major process steps performed in the facility. Integrated plants perform all of the process steps, whereas nonintegrated plants, in general, perform only the last three steps.

The IDM uses a five-step process flow to estimate UEC values. Steps for crude steel production are different for steel made primarily from raw materials (primary steel) than for scrap steel reformed into new steel (secondary steel).

Crude primary steel is generally a two-step process:

1. Coke ovens convert metallurgical coal into coke.

2. Iron is reduced in a blast furnace with coke and limestone and is then charged into a basic oxygen furnace to produce crude steel.

Secondary steel is generally a one-step process. An electric arc furnace produces raw steel from an all-scrap (recycled materials) charge, which can be supplemented with direct-reduced iron (DRI). Like a blast furnace, DRI reduces iron but uses much lower temperatures than a blast furnace.

The steps to turn crude steel into finished products are the same for primary and secondary steel:

1. Crude steel is cast into blooms, billets, or slabs using continuous casting. Of all U.S. steel, 97% is produced using continuous casting.

2. Steel is then hot-rolled into various mill products. Some of these products are sold as hot-rolled mill products, while others are further cold rolled to impart surface finish or other desirable properties.

The technology slate in each of these process steps evolves over time and depends on the relative cost of equipment, the cost of fuel, and fuel efficiency. The latest CIMS database determines and calibrates the IDM base-year technology slate based on the 2018 MECS and USGS physical output for 2018.

Producers switch from a blast furnace and basic oxygen furnace to an electric arc furnace when coal prices rise. If coal prices don’t rise or only rise slightly, the percentage of steel production from electric arc furnaces marginally increases over the projection period. Based on generally accepted industry trend outlooks, the proportion of steel production from blast furnaces and basic oxygen furnaces does not increase.

Aluminum industry

For the aluminum industry submodule, each step (alumina production, anode production, electrolysis for primary aluminum production, and melting for secondary production) has several technology choices for new capacity with known fuel types and efficiencies, as well as other operating characteristics. We know technology shares at the national level, and we base regional fuel breakouts on allocations from EIA data.

The aluminum industry has both primary and secondary production processes, which vary widely in their energy demands. Recently, secondary aluminum's share of total aluminum production capacity has increased significantly relative to its historical share. A number of primary smelters have closed during the past few years and may not reopen. Therefore, experts expect the share of secondary aluminum to constitute at least 75% of total aluminum output through 2050. We assume no new primary aluminum plants will be built in the United States before 2050, although very limited capacity expansion of existing primary smelters may occur.

Some technologies are options for both processes, and others are options for only one process:

- Primary smelting (Hall-Heroult electrolysis cell) is represented by four pre-bake anode technologies that denote standard and retrofitted choices and one inert anode-wetted cathode choice.
- Anode production, used in primary production only, is represented by three natural gas-fired furnaces under various configurations in forming and baking pre-bake anodes and the formation of Söderberg anodes. Anodes are a requirement for the Hall-Heroult process.
- Alumina production (Bayer Process) is used in primary production only and selects between existing natural gas facilities and those with retrofits.
- Secondary production selects between two natural gas-fired melting furnaces: standard and high efficiency.

The technology slate in each of these process steps evolves over time and depends on the relative cost of equipment, cost of fuel, and fuel efficiency, subject to the constraint that the secondary production share is at least 75% of all aluminum production. We calibrate the latest IDM base-year technology slate to CIMS bandwidth studies from the U.S. Department of Energy's Advanced Manufacturing Office,[8] the 2018 MECS, and USGS data on the physical production of primary and secondary aluminum. The submodule assumes all new capacity for aluminum production, both for replacement capacity and increased production needs, is either idled primary production capacity that comes back online or new secondary production capacity.

Buildings component

The total buildings energy demand by industry for each region is a function of regional industrial employment and output. The IDM estimates building energy consumption for building lighting, HVAC (heating, ventilation, and air conditioning), facility support, and onsite transportation. We divide space heating further to estimate how much energy steam and the direct combustion of fossil fuels provide (Table 7). The submodule also estimates energy consumption in the buildings component for an industry based on regional employment and output growth for that industry using the 2018 MECS as a basis.

Table 7. Energy consumption for buildings model component, base year

trillion British thermal units

Industry	Census region	Lighting—electricity	HVAC—electricity	HVAC—natural gas	HVAC—steam	Facilities support total	Onsite transportation total
Food	East	0.5	3.1	3.1	1.0	2.0	0.2
	Midwest	1.7	10.9	14.3	4.5	9.3	1.4
	South	2.2	14.4	28.5	9.0	15.6	1.1
	West	0.7	4.7	7.1	2.2	4.1	0.3
Paper	East	0.9	1.0	1.1	0.0	0.4	0.1
	Midwest	3.3	3.7	4.8	0.0	1.6	2.2
	South	4.3	4.8	9.7	0.0	2.5	2.6
	West	1.4	1.6	2.4	0.0	0.7	0.2
Bulk chemicals	East	1.1	1.8	1.2	0.0	0.7	0.0
	Midwest	3.7	6.2	5.4	0.0	3.0	0.8
	South	4.9	8.2	10.8	0.0	5.4	0.2
	West	1.6	2.7	2.7	0.0	1.4	0.0
Glass	East	0.3	0.4	0.4	0.0	0.0	0.0
	Midwest	1.0	1.3	1.6	0.0	0.0	0.0
	South	1.3	1.7	3.2	0.0	0.0	0.0
	West	0.4	0.6	0.8	0.0	0.0	0.0
Cement and lime	East	0.1	0.1	0.0	0.0	0.0	0.0
	Midwest	0.3	0.3	0.0	0.0	0.0	1.6
	South	0.4	0.4	0.0	0.0	0.0	0.4
	West	0.1	0.1	0.0	0.0	0.0	0.0
Iron and steel	East	0.7	0.6	1.1	0.0	0.3	0.0
	Midwest	2.3	2.0	4.8	0.0	1.1	3.1
	South	3.1	2.6	9.7	0.0	2.1	0.9
	West	1.0	0.9	2.4	0.0	0.5	0.0
Aluminum	East	0.3	0.2	0.5	0.0	0.3	0.0
	Midwest	1.0	0.7	2.2	0.0	1.3	0.8
	South	1.3	0.9	4.3	0.0	1.8	0.2
	West	0.4	0.3	1.1	0.0	0.6	0.0
Fabricated metal products	East	1.2	1.6	1.8	0.5	0.4	0.1
	Midwest	4.3	5.6	8.3	2.2	1.5	0.6
	South	5.6	7.3	16.7	4.5	2.4	2.1
	West	1.8	2.4	4.1	1.1	0.7	0.1

Machinery	East	0.8	1.2	1.5	0.3	0.3	0.1
	Midwest	3.0	4.3	6.7	1.2	1.3	0.5
	South	3.9	5.7	13.5	2.4	1.8	1.3
	West	1.3	1.8	3.3	0.6	0.6	0.1
Computer products	East	0.6	1.8	0.9	0.4	0.5	0.0
	Midwest	2.0	6.3	4.0	1.6	1.9	0.0
	South	2.6	8.3	8.1	3.3	2.8	0.0
	West	0.8	2.7	2.0	0.8	0.8	0.0
Transportation equipment	East	1.9	2.9	3.4	1.1	0.7	0.2
	Midwest	6.6	10.3	15.6	5.0	2.8	1.7
	South	8.7	13.5	31.2	10.1	4.2	2.8
	West	2.8	4.4	7.8	2.5	1.2	0.3
Electrical equipment	East	0.3	0.7	0.5	0.2	0.2	0.0
	Midwest	1.0	2.3	2.4	0.9	0.6	0.1
	South	1.3	3.0	4.8	1.8	1.0	0.8
	West	0.4	1.0	1.2	0.4	0.3	0.0
Wood products	East	0.5	0.5	0.4	1.8	0.2	0.0
	Midwest	1.7	1.7	1.6	8.1	0.6	5.1
	South	2.3	2.3	3.2	16.3	1.0	3.8
	West	0.7	0.7	0.8	4.0	0.3	0.0
Plastic products	East	1.2	1.6	1.2	0.2	0.5	0.2
	Midwest	4.3	5.6	5.6	1.0	1.9	1.0
	South	5.7	7.4	11.3	2.0	2.7	2.6
	West	1.8	2.4	2.8	0.5	0.8	0.3
Balance of manufacturing	East	0.0	5.3	5.5	2.3	3.0	0.0
	Midwest	0.0	18.8	25.0	10.4	14.0	0.0
	South	0.0	24.8	50.0	20.8	19.5	0.0
	West	0.0	8.1	12.4	5.2	5.2	0.0

Data source: U.S. Energy Information Administration, *Manufacturing Energy Consumption Survey 2018*
Note: HVAC=heating, ventilation, and air conditioning

Boiler, steam, and cogeneration component

The steam demand and byproducts from the PA and BLD components are passed to the BSC component, which applies a heat rate and a fuel share equation to the boiler steam requirements to compute the required energy consumption (Table 8). The iron and steel industry and the pulp and paper industry are exceptions; these industries have independent BSC and cogeneration-related modeling that is calculated during the PA step.

The boiler fuel shares apply only to the fuels that are used in boilers for steam-only applications. The next section describes fuel use for the combined heat and power (CHP) share of steam demand. The IDM assumes some fuel switching for the remainder of the boiler fuel use and calculates it with a logit-sharing equation, where fuel shares are a function of fuel prices.

The IDM assumes byproduct fuels are consumed without regard to price and are independent of purchased fuels. The PA component estimates the production of byproduct fuels. We base the boiler fuel share equations and calculations on the 2018 MECS and information from the Council of Industrial Boiler Owners.[9]

Table 8. Energy consumption for boiler, steam, and cogeneration model component, base year

trillion British thermal units

Industry	Census region	Natural gas	Coal	Renewables	Petroleum	Electricity
Food	East	23.0	6.2	4.8	0.1	0.7
	Midwest	104.3	21.2	6.5	2.2	2.6
	South	208.8	6.8	41.8	6.6	3.5
	West	51.9	2.8	4.9	0.1	1.1
Bulk chemicals	East	65.2	16.4	0.3	6.7	0.2
	Midwest	295.5	56.3	0.4	21.4	0.7
	South	591.4	17.9	2.9	332.5	0.9
	West	146.9	7.4	0.3	5.4	0.3
Glass	East	0.1	0.0	0.0	0.0	0.0
	Midwest	0.3	0.0	0.0	0.0	0.0
	South	0.5	0.0	0.0	0.0	0.0
	West	0.1	0.0	0.0	0.0	0.0
Cement and lime	East	0.0	0.0	0.1	0.0	0.0
	Midwest	0.0	0.0	0.1	0.0	0.0
	South	0.0	0.0	0.7	0.0	0.0
	West	0.0	0.0	0.1	0.0	0.0
Fabricated metal products	East	0.8	0.0	0.0	0.0	0.1
	Midwest	3.5	0.0	0.0	0.0	0.3
	South	7.0	0.0	0.0	0.0	0.4
	West	1.7	0.0	0.0	0.0	0.1
Machinery	East	0.4	0.0	0.0	0.0	0.1
	Midwest	1.9	0.0	0.0	0.0	0.3
	South	3.8	0.0	0.0	0.0	0.4
	West	0.9	0.0	0.0	0.0	0.1
Computer products	East	0.7	0.0	0.0	0.0	0.1
	Midwest	3.0	0.0	0.0	0.0	0.3
	South	5.9	0.0	0.0	0.0	0.4
	West	1.5	0.0	0.0	0.0	0.1
Transportation equipment	East	1.5	0.0	0.0	0.4	0.1
	Midwest	6.7	0.0	0.0	0.6	0.3
	South	13.5	0.0	0.0	2.1	0.4
	West	3.3	0.0	0.0	0.0	0.1

Electrical equipment	East	0.4	0.0	0.0	0.0	0.0
	Midwest	1.6	0.0	0.0	0.0	0.0
	South	3.2	0.0	0.0	0.0	0.0
	West	0.8	0.0	0.0	0.0	0.0
Wood products	East	1.1	0.0	38.3	0.1	0.1
	Midwest	5.1	0.0	51.2	0.3	0.3
	South	10.2	0.0	331.1	0.5	0.5
	West	2.5	0.0	38.5	0.1	0.1
Plastic products	East	1.8	0.0	0.0	0.0	0.0
	Midwest	8.3	0.0	0.0	0.0	0.0
	South	16.7	0.0	0.0	0.0	0.0
	West	4.1	0.0	0.0	0.0	0.0
Balance of manufacturing	East	12.0	0.3	1.6	1.4	1.0
	Midwest	54.3	1.1	2.1	7.8	3.7
	South	108.7	0.4	13.7	49.2	4.9
	West	27.0	0.2	1.6	1.6	1.6

Data source: U.S. Energy Information Administration, *Manufacturing Energy Consumption Survey 2018*

Combined heat and power

Combined-heat-and-power (CHP) plants, which are designed to produce both electricity and useful heat, have been used in the industrial sector for many years. In the submodule, we base the CHP estimates for end-use industries on the assumption that the historical relationship between industrial steam demand and CHP will continue in the future and that the rate of additional CHP penetration will depend on the economics of retrofitting CHP plants to replace steam generated from existing non-CHP boilers. The technical potential for CHP is based on supplying steam requirements. We then determine capacity additions by:

- The interaction of CHP investment payback periods (with the time value of money included) derived using operating hours reported in our published statistics
- Market penetration rates for investments with those payback periods
- Regional deployment of these systems as characterized by *collaboration coefficients*, which quantify the relative ease of installing and connecting CHP to the grid for a given region (Table 9)
- Assumed installed costs for the CHP systems (Table 10)

Table 9. Regional collaboration coefficients for CHP deployment

Census region	Collaboration coefficient
East	0.335
Midwest	0.175
South	0.235
West	0.255

Data source: U.S. Energy Information Administration, Form EIA-860, *Annual Electric Generator Report*; the American Council for an Energy-Efficient Economy, 2017 State Energy Efficiency Scorecard (Washington, DC, September 2017)
Note: CHP=combined heat and power

Table 10. Cost characteristics of industrial CHP systems

System	Capacity (MW)	2018 overall heat rate (Btu/kWh)	2018 installed cost (2018$/kW)	2050 overall heat rate (Btu/kWh)	2050 installed cost (2018$/kW)
Reciprocating engine	1.2	8,713	$2,586	8,597	$2,553
	3.0	8,654	$2,010	8,538	$1,984
Gas turbine	4.6	9,768	$1,839	9,252	$1,741
	10.4	10,807	$1,842	10,236	$1,751
	23.2	10,276	$1,309	9,733	$1,245
	45.0	8,933	$1,162	8,461	$1,106
Combined cycle	117.0	6,789	$1,581	6,430	$1,482
	376.0	6,270	$1,267	5,992	$1,211

Data source: Leidos, *Distributed Generation, Battery Storage, and Combined Heat and Power System Characteristics and Costs in the Buildings and Industrial Sectors* (Washington, DC, May 2020)
Note: CHP=combined heat and power, MW=megawatts, Btu=British thermal units, kW=kilowatt, kWh=kilowatthours

CHP for steel, paper, and aluminum industries

For steel and paper, the IDM computes boiler and CHP capacity and generation as part of the PA step. Steam demand for each process is a non-energy demand for each process step. The submodule calculates the initial steam and CHP in the IDM base year based on historical Form EIA-860 data through 2021, and the submodule assumes a specific CHP share in the final projection year. Specific CHP and boiler technology shares in the IDM base year and final projection year are then chosen from a slate of user-assumed technologies with different fuels. In the intervening years, the IDM interpolates shares of CHP and boilers as well as technology shares.

For the aluminum industry, the structure is slightly different. The boilers step (including CHP) is a distinct process step in the manufacture of alumina from bauxite. We set initial boiler and CHP technology shares in the IDM base year based on research and analyst judgement.

Key assumptions—nonmanufacturing

The nonmanufacturing sector consists of three industries: agriculture, mining, and construction. These industries all use electricity, natural gas, diesel fuel, and gasoline. The mining industry also uses coal and residual fuel oil; the construction industry uses propane and other petroleum products such as asphalt and road oil. Except for oil and natural gas extraction, almost all of the energy use in the nonmanufacturing sector takes place in the PA step. Oil and natural gas extraction uses residual fuel oil in the BSC component.

Unlike the manufacturing sector, the nonmanufacturing sector does not have a single source of data for base-year energy consumption. Instead, we derive UECs for the nonmanufacturing sector from various sources of data collected by a number of government agencies.

We revise the nonmanufacturing historical data for base-year energy consumption using EIA data and U.S. Census Bureau sources to provide more realistic projections of diesel and gasoline for off-road vehicle use and to allocate natural gas, HGLs, and electricity consumption. We used *Fuel Oil and Kerosene Sales 2019*,[10] the U.S. Department of Agriculture's *Agricultural Resource Management Survey* (ARMS),[11] and the U.S. Census Bureau's 2017 Economic Census for Mining[12] and Census for Construction.[13]

Agriculture subsector

U.S. agriculture consists of three major industries:

- Crop production, which depends primarily on regional environments and crops demanded
- Animal production, which largely depends on food demands and feed accessibility
- Forestry, logging, and all other agricultural activities

These subindustries have historically been tightly grouped because they compete for the same land. For example, humans cannot eat some of the crops produced for animal feed. Similarly, forests provide the feedstock for the paper and wood industries, but they are not good for growing crops and limit or prevent animals from grazing. NEMS does not model forestry and logging.

Energy consumption in the agricultural sectors modeled in NEMS—crops and other agricultural activity—are disaggregated into three activities: irrigation, buildings, and vehicles. We derive the TPC for each activity from the Commercial Demand Module (CDM) and the Transportation Demand Module (TDM). Each TPC for irrigation depends on the relative change in energy intensity for ventilation from the CDM. Similarly, each TPC for buildings depends on a weighted average of the change in intensity for heating, lighting, and building shells from the CDM. Each TPC for vehicles changes over time, depending on the relative intensity change of trucks from the TDM.

We extract baseline energy consumption data for the two agriculture sectors (crops and other agriculture) from the Census of Agriculture and from a tabulation by the U.S. Department of Agriculture, National Agricultural Statistics Service (NASS). Expenditures for four energy sources are collected from crop farms and livestock farms as part of the ARMS. We convert these data from dollar expenditures to energy quantities using fuel prices from NASS and our own data.

Mining subsector

The mining subsector is made up of three parts: coal mining, metal and nonmetal mining, and oil and natural gas extraction. Energy use is based on the equipment and onsite vehicles used at the mine. All mines use extraction equipment and lighting, but only coal and metal mines and nonmetal mines use grinding and ventilation. Similar to the agriculture submodule described above, efficiency changes in buildings and transportation equipment influence each TPC.

The Coal Market Module provides coal mining production data. We assume 70% of coal is mined at the surface and the rest is mined underground. As these shares change, however, so does the energy consumed because surface mines use less energy overall than underground mines. In addition, the energy consumed for coal mining depends on coal mine productivity, which is also obtained from the Coal Market Module. Diesel fuel and electricity are the predominant fuels used in coal mining. We calculate electricity used for coal grinding by using the raw grinding process step from the cement submodule. In metal and nonmetal mining, energy use is similar to coal mining. We derive the output used for metal and nonmetal mining from the MAM's variable for other mining, which also provides the shares of each type of mining.

For oil and natural gas extraction, natural gas used as lease and plant fuel makes up the majority of fuel used for extraction and processing. The Natural Gas Market Module computes lease fuel and fuel used in natural gas processing plants. Both of these uses of natural gas are considered industrial consumption in the aggregate, but the IDM does not compute them. The IDM computes the other fuels in the oil and natural gas extraction sector, including fuel oil, diesel, and electricity, based on oil and natural gas production data from the Oil and Gas Supply Module. Energy use depends on the fuel extracted, whether the well is conventional or unconventional (for example, extraction from tight and shale formations), percentage of dry wells, and well depth.

Construction subsector

The construction subsector uses diesel fuel, gasoline, electricity, and propane as energy sources. Construction also uses asphalt and road oil as nonfuel energy sources. Asphalt and road oil use is tied to state and local government real investment in highways and streets, provided by the MAM. Each TPC for diesel and gasoline fuels is directly tied to the TDM's heavy- and medium-duty vehicle efficiency projections. For non-vehicular construction equipment, each TPC is a weighted average of vehicular TPC and highway investment.

Legislation and regulations

Inflation Reduction Act, 2022 (IRA2022)

IRA2022 extended the combined-heat-and-power (CHP) investment tax credit (ITC) from the Consolidated Appropriations Act of 2021 through the end of 2024. However, the IRA2022 also changed the ITC as it applies to 2023 on. Instead of a flat 10% credit, a project receives a baseline 6% ITC credit. If a project meets prevailing wage and apprenticeship requirements set out in the bill, this percentage is instead 30%.

Furthermore, if the project meets domestic material content requirements defined in the bill, the ITC increases by a further 10 percentage points, or by 2 percentage points if the project does not meet the material requirements.

Finally, if a project is located in an energy community as defined in the bill, the ITC is increased by 10 percentage points. If the project is not located in an energy community, the ITC is increased by 2 percentage points.

As a result, the possible ITC ranges from a minimum of 10% to a maximum of 50%.[14] The IDM uses the minimum ITC for the Reference case and core side cases, given the time window for the new ITC structure compared to the planning time for industrial projects.

Consolidated Appropriations Act, 2021 (CAA2021)

CAA2021 extended the 10% CHP ITC from the Bipartisan Budget Act of 2018 through the end of 2023. It now applies for all qualifying CHP facilities that begin construction before January 1, 2024.[15]

Bipartisan Budget Act of 2018 (BBA2018)

BBA2018 retroactively extended the 10% CHP ITC from the Energy Improvement and Extension Act of 2008 (EIEA2008) through the end of 2021. The ITC in EIEA2008 originally spanned from 2008 through the end of 2016, but BBA2018 applied the ITC to all qualifying CHP facilities that began construction before January 1, 2022.[16]

The Energy Independence and Security Act of 2007 (EISA2007)

EISA2007 suspends motor efficiency standards established under the Energy Policy Act of 1992 (EPACT1992) for purchases made after 2011. This law increases or creates minimum efficiency standards for newly manufactured and imported general-purpose electric motors (Section 313 of EISA2007). The efficiency standards are raised for general-purpose, integral-horsepower induction motors, except for fire pump motors. Minimum standards were created for seven types of poly-phase, integral-horsepower induction motors and National Electrical Manufacturers Association (NEMA) design B motors (201–500 horsepower) that were not previously covered by EPACT standards. In 2013, the Energy Policy and Conservation Act was amended (Public Law 113-67), and efficiency standards were revised in a subsequent U.S. Department of Energy (DOE) rulemaking (10 CFR 431.25). For motors manufactured after June 1, 2016, efficiency standards for current regulated motor types[17] were expanded to include 201–500 horsepower motors. In addition, special- and definite-purpose motors from 1–500 horsepower and NEMA design A motors from 201–500 horsepower were subject to efficiency standards. The AEO models 2014 regulations by modifying the specifications for new motors in the electric motor technology choice submodule.

Energy Policy Act of 1992 (EPACT1992)

EPACT1992's efficiency standards for boilers, furnaces, and electric motors affect the IDM. The IDM assumes 80% efficiency for natural gas burners and 82% for oil burners. These efficiencies meet the EPACT1992 standards. EPACT1992 requires minimum efficiencies for all motors up to 200 horsepower purchased after 1998. The choices offered in the motor efficiency assumptions are all at least as efficient as the EPACT minimums.

Clean Air Act Amendments of 1990 (CAAA1990)

CAAA1990 contains numerous provisions that affect industrial facilities. Three major categories of these provisions include:

- Process emissions
- Emissions related to hazardous or toxic substances
- Sulfur dioxide (SO_2) emissions

Process emission requirements were specified for several industries and activities (40 CFR 60). Emissions of almost 200 hazardous or toxic substances are also limited by the law (40 CFR 63). These requirements are not explicitly represented in the NEMS IDM because they are not directly related to energy consumption projections.

The EPA is required under federal law to regulate industrial SO_2 emissions when total industrial SO_2 emissions exceed 5.6 million tons per year (Section 406 of the CAAA1990 and 42 USC 7651). Because industrial coal use (the main source of SO_2 emissions) has been declining, EPA does not anticipate that specific industrial SO_2 regulations will be required (U.S. Environmental Protection Agency, National Air Pollutant Emission Trends: 1900–1998, EPA-454/R-00-002, March 2000, Chapter 4). Further, because we do not project higher industrial coal use, we do not expect the limit on industrial SO_2 emissions to affect industrial energy consumption projections. The electric power sector includes emissions from coal-to-liquids CHP plants because they are subject to the separate emission limits of large electricity-generating plants.

Maximum Achievable Control Technology for Industrial Boilers (Boiler MACT)

Air toxics are regulated through the National Standards for Hazardous Air Pollutants for industrial, commercial, and institutional boilers (Section 112 of the Clean Air Act). The AEO models final regulations, known as Boiler MACT. Pollutants covered by Boiler MACT include several hazardous air pollutants:

- Hydrogen chloride
- Mercury, dioxins, and furans
- Carbon monoxide
- Particulate matter

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. Because natural gas area source boilers are exempt from regulation under Boiler MACT, the IDM adds to the cost of coal-, fuel oil-, and biomass-fired area source boilers.

Finally, the MAM models Boiler MACT as an upgrade cost. These upgrade costs are classified as nonproductive costs, which are not associated with efficiency improvements. These costs in the MAM reduce shipment values coming into the IDM.

California Assembly Bill 32: Emissions Cap-and-Trade as Part of the Global Warming Solutions Act of 2006 (AB32) as Amended by California Senate Bill 32, 2016 (SB32)

AB32 established a comprehensive, multiyear program to reduce greenhouse gas (GHG) emissions in California, including a cap-and-trade program.[18] In addition to the cap-and-trade program, AB32 authorizes

- The low-carbon fuel standard
- Energy efficiency goals and programs in transportation, buildings, and industry
- Combined-heat-and-power goals
- Renewable portfolio standards

The AEO models the cap-and-trade provisions for industrial facilities, refineries, and fuel providers. The NEMS Electricity Market Module models allowance price, representing the incremental cost of complying with AB32 cap-and-trade by a region-specific emissions constraint. This allowance price, when added to market fuel prices, effectively results in higher fuel prices in the demand sectors. The NEMS also models limited banking and borrowing of allowances, as well as a price containment reserve and offsets. AB32 is not modeled explicitly in the IDM, but it enters the module implicitly through higher effective fuel prices and macroeconomic effects of higher prices, all of which affect energy demand and emissions, primarily in the Pacific Census Division.

SB32 was enacted in September 2016 and requires California regulators to plan for a 40% reduction in GHG emissions (below 1990 levels) by 2030.[19] The AEO models emissions goals in the cap-and-trade program assuming a ceiling on CO_2 allowance prices to prevent infeasible solutions or extremely high allowance prices. Further cost-effective emissions reductions are not available, and so, the allowance price is at the price ceiling. The IDM assumes this price ceiling is slightly higher than the price of the Tier 3 Allowance Price Containment Reserve.

The cap-and-trade program is only one part of California's GHG reduction strategy. According to the California Air Resources Board, the cap-and-trade program is assumed to comprise less than 30% of total GHG emissions reductions targets.[20] Emissions reductions targeted by the other GHG reduction programs described above affect the industrial sector only indirectly.

Notes and sources

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[12] 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).

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

[14] U.S. Congress, "H.R.5376 – Inflation Reduction Act of 2022", Title I, Subtitle D—Energy Security, Sec. 13102, 117th Congress (2021-2022), became Public Law No: 117-169 on August 16, 2022.

[15] U.S. Congress, "H.R.133 - Consolidated Appropriations Act, 2021", Division EE, Title I, Subtitle C—Extension of Certain Other Provisions, Sec. 132, 116th Congress (2019-2020), became Public Law No: 116-260 on December 27, 2020.

[16] U.S. Congress, "H.R.1892 - Bipartisan Budget Act of 2018", Division D, Title I, Subtitle C—Extension and phaseout of energy credit, Sec. 40411, 115th Congress (2017–2018), became Public Law No: 115-123 on February 9, 2018.

[17] Federal Register 79 FR 103, pp. 30934-31014, Washington, DC, May 29, 2014.

[18] California Air Resources Board "California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10, Article 5 §95800 - §96022" (Sacramento, California, June 14, 2014).

[19] California Global Warming Solutions Act §38566 as amended (Sacramento, California, September 8, 2016).

[20] Based on personal communication with CARB staff and calculations of Table II-3, page 43, of California Air Resources Board "The 2017 Climate Change Scoping Plant Update," (Sacramento, California, January 20, 2017).