DATABASE DOCUMENTATION

RIO US Database

United States

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1 Overview

1.1 Scope and organization

The RIO US database holds the input data that the RIO capacity expansion and operations model reads for the United States. It covers the supply side of the energy system (electricity generation and storage, fuel conversion, industrial materials production, hydrocarbon extraction, transmission and pipelines, commodity supply curves), the demand-side quantities and technology characterizations that EnergyPATHWAYS (EP) writes for RIO, temporal profiles, policy constraints, and greenhouse gas definitions. The model that consumes these data is documented in the companion *RIO Model* document, and EP in the companion *EnergyPATHWAYS Model* document. The EP inputs from which the demand-side tables are produced are documented in the companion *EnergyPATHWAYS US Database*.

The database is a directory of comma-separated tables organized in six top-level folders:

Folder	Contents
Demand	Demand subsectors and technologies, payback-acceptance curves, and the exogenous demand and cost tables written by EP
Gases	Gas accounting weights
Geography and Currency	Geographic units, the county-level allocation table, map keys, currency exchange rates, and the price index
Policy Constraints	Emissions caps and prices, carbon-intensity standards, and planning reserve requirements
Shapes	Shape metadata, hourly and monthly profile data, and day-clustering weights
Supply	Blends (energy carriers and material products), commodities (primary resources and trade), supply technologies, and transmission

A table is a .csv file, a compressed .csv.gz file, or a .csvd folder of files (shards) with identical columns that RIO concatenates into one table. Most tables are produced by scripted builders that read public source data. Policy constraints and the characterization of industrial and fuel conversion technologies are maintained by hand from the cited literature.

This document describes the data and run settings of the RIO runs: the data the model reads and the technologies, commodities, and carriers they define. Section 2 gives the run configuration, Section 3 describes the derivation of the data by domain, Section 4 lists the tables, and Appendix A lists the source of the data in each table.

1.2 Geography

Model zones. RIO solves over the us_eer2 geography: 27 zones covering the contiguous United States, one zone each for Alaska and Hawaii, and one non-physical trade zone named export. Each zone is a set of counties; county membership is recorded in GEOGRAPHIES_SPATIAL_JOIN.

Region	Zones
West	washington, oregon, northern_california, southern_california, great_basin, desert_southwest, rockies
Central	northern_plains, southern_plains, minnesota, upper_midwest, illinois_midwest, michigan, texas_west, texas_east, gulf_south
East	ohio_appalachia, tennessee_valley, southeast, florida, carolinas, virginia, mid_atlantic, upstate_new_york, new_york_city, northern_new_england, southern_new_england
Non-contiguous	alaska, hawaii
Trade	export

The export zone represents trading partners outside the modeled system. International pipeline crossings to Canada and Mexico terminate in it, export commodities deliver to it, and conversion technologies that serve export markets allocate output to it. Its planning reserve margin is zero, and it carries zero weight in representative-day selection.

Native geographies. Each table row declares the geography in which its values are expressed (geography) and the unit within that geography (gau, geographic aggregation unit). RIO maps every row from its native geography to the model zones when the run is set up, so a table can hold national, regional, state, county, or source-specific values side by side. The geographies used are:

Geography	Units	Used for
united states, global (all)	1	National values and values that do not vary by location
state	52	State policy, delivered coal prices, CO_2 storage, biomass, demand response
county, fips, county_geoid	about 3,140	Existing plants and facilities, biomass potential
census division, census region	10, 5	Petroleum product delivery margins, existing cement, clinker, and lime capacity, some industrial efficiency rows
emmr	30	NEMS Electricity Market Module regions, used for electricity delivery cost
us_eer, us_eer_w_state	28, 91	An earlier EMM-based zone system and its intersection with states; us_eer_w_state is used for renewable resource supply curves
reeds zone	137	ReEDS balancing areas, used for wind and solar profiles
iecc climate zone by state	113	Temperature and geothermal profiles
hsm_district, hsm_region, offshore_district, canada_region	66, 8, 8, 2	NEMS Hydrocarbon Supply Module geographies for oil and gas supply
us_eer2	30	Model zones

Allocation keys. When a value is mapped from one geography to another, RIO weights each county by an allocation quantity. GEOGRAPHIES_SPATIAL_JOIN holds one row per county with its membership in every geography and the allocation quantities, such as population, employment, value of shipments, generating capacity, oil and gas production, and the resource-class potentials of the supply curves. A row selects its allocation quantity through geography_map_key; a row with no map key is allocated on the default basis, which in the runs is the 2010 complete-count household count.

1.3 Time

Tables indexed by year hold values for calendar years; tables indexed by vintage hold values for the year in which an asset enters service. Rows need not be given for every year. Each row carries an interpolation_method and an extrapolation_method, and RIO fills the model years from the given points with those methods (linear interpolation, nearest value, forward fill, logistic, exponential growth at extrapolation_growth_rate, and others). The optimization years are given in Section 2.3. Most supply-side series run to 2050; the oil and gas supply tables cover 2026 to 2050.

Hourly profiles carry a weather_datetime index. The runs use the 2023 weather year for all hourly profiles, in both models.

1.4 Units and currency

Values are stored in the units of their source, and each table states its units in a unit column (or in specific columns such as mass_unit, capacity_unit, or area_unit_numerator). RIO converts all values to a common unit and currency basis at load time; the basis of the runs is given in Section 2.5. Monetary values carry currency and currency_year. Most supply-side costs are in US dollars of 2022 (values from the NREL Annual Technology Baseline 2024), 2021 (industrial technology values from the NEMS Industrial Demand Module inputs), 2025 (values derived from the Annual Energy Outlook 2026 and the NEMS restart file, freight costs, and electric transmission costs), or 2023 and 2024 (pipeline costs). INFLATION_CONVERSION holds the US price index used to convert between currency years, and CURRENCY_CONVERSION holds the exchange rates used to convert values reported in other currencies.

1.5 Alternative data sets

Where a table holds alternative data sets, the runs use the one described in this document, and the cases differ only in the emissions price, the sectoral intensity standards, and the national CO_2 emissions cap (Section 2.1).

1.6 Common columns

Column	Meaning
name	Identifier of the technology, blend, commodity, subsector, constraint group, or corridor
source, notes	Citation and derivation notes
geography, gau	Native geography of the row and the unit within it (Section 1.2)
year, vintage	Calendar year of the value, or service-entry year of the asset
value, unit	The parameter value and its unit
currency, currency_year	Currency and price-year basis of monetary values

Column	Meaning
sector	Consuming sector: residential, commercial, productive (industry and agriculture), transportation, or upstream (consumption by supply-side technologies)
bin	Step of a supply curve, or operating mode

1.7 Naming conventions

Technology names identify existing and new assets and resource classes. Existing technologies carry the prefix existing_ and are disaggregated by plant. A suffix |n denotes a resource class or bin of a technology with a supply curve, for example onshore wind|3 or geothermal egs|5. Transmission corridors are named from||to||type||n, where type is the corridor kind (for example electricity, electricity new line, ng b, ng looping b, hydrogen b new, co2 b new) and n distinguishes parallel corridors between the same two zones. In the oil and gas supply tables, each named play (for example marcellus gas or wolfcamp oil) and each resource type (for example domestic conventional gas) is its own commodity, and the suffix (legacy) denotes production from wells drilled before the first model year.

Energy carriers and material products are called blends in the database tables. A blend is supplied and consumed by technologies and commodities; examples are electricity, pipeline gas blend, hydrogen blend, diesel blend, co2 sequestration blend, clinker blend, and cement blend. A commodity is a primary resource or traded quantity with a cost and a potential, such as a biomass feedstock, a hydrocarbon play, a CO_2 storage resource, or an export market. The runs model 114 new-build technology types, 75 existing technology types, 140 commodities (136 supply commodities and 4 export markets), and 73 blends (56 measured in energy and 17 in mass).

2 Run configuration

This section gives the settings of the runs. The model features they switch on and off are defined in the *RIO Model* document.

2.1 Cases

The runs comprise four cases. They share every input except the emissions price, the sectoral carbon-intensity standards, and the national CO_2 emissions cap, and they share the same representative days.

Case	Emissions price	Sectoral carbon-intensity standards	National CO_2 emissions cap
Reference	None	None	None
Carbon price	CO_2 price of zero through 2030, then 50, 100, 150, and 200 US dollars (2024) per tonne in 2035, 2040, 2045, and 2050, in every zone	None	None
Emissions intensity cap	None	Ceilings on six product groups from 2035 (table below)	None
Alternative cap	None	None	4,152, 3,570, 2,743, and 1,984 Mt CO_2 in 2035, 2040, 2045, and 2050

In the carbon price case the price applies to CO_2 only; every other gas carries a price of zero.

In the alternative cap case, the primary emissions constraint limits the CO_2 emissions of the us zone group, which comprises every zone except export, to 41,519,872, 35,699,167, 27,430,284, and 19,841,878 hectotonnes in 2035, 2040, 2045, and 2050. The cap is infinite in 2026 and 2030, and the export zone carries no cap in any year. Each year's cap equals the CO_2 emissions of the us zone group in the solution of the emissions intensity cap case for that year. The emissions price in this case is zero in every year.

In the emissions intensity cap case, BLEND_GROUP_EMISSIONS_INTENSITY_CAP gives six product groups a national ceiling on emissions per unit of product. The ceilings are infinite in 2026 and 2030, and the ammonia group carries no finite ceiling in any year. Each ceiling is the emissions intensity that the group reaches in the solution of the carbon price case in that year, computed with the deemed intensities of BLEND_DEEMED_EMISSIONS and with the products of each capped group deemed at the group's ceiling. The deemed intensities are the per-blend emission intensities of the reference case. BLEND_DEEMED_EMISSIONS enters only the intensity standards, so it affects only this case.

Product group	Unit	2035	2040	2045	2050
Electricity	kg CO_2 per MWh	133.2	69.7	29.1	13.9
Pipeline gas	kg CO_2 per MMBtu	54.0	53.3	52.7	52.1
Liquid fuels (diesel, gasoline, jet fuel, fuel oil, with ethanol as an input)	kg CO_2 per MMBtu	76.2	75.2	67.9	42.6
Hydrogen (all hydrogen blends)	kg CO_2 per MMBtu	66.2	65.1	28.8	2.9
Cement	t CO_2 per t cement	0.525	0.399	0.060	0.043
Steel	t CO_2 per t steel	0.722	0.649	0.375	0.343

The cement group counts, per tonne of cement, the fuel of the clinker kiln burners; the process CO_2, electricity, and capture of clinker production; and the grinding electricity and clay-calcining heat or electricity of cement production. The steel group counts the steel production and finishing routes per tonne of steel.

2.2 Zones

The runs resolve the 29 physical zones of the us_eer2 geography (27 contiguous zones, Alaska, and Hawaii) and the export trade zone (Section 1.2). EP resolves the same zones. Of the 62 counties of New York State, new_york_city holds eight: the five counties of New York City, Westchester, Nassau, and Suffolk. The other 54 are in upstate_new_york.

2.3 Optimization years

RIO is solved for six optimization years, each with a gap weight equal to the number of calendar years it represents. The weights span the 25 years from 2026 to 2050.

Optimization year	2026	2030	2035	2040	2045	2050
Gap weight (years)	1	4	5	5	5	5

Each foresight window contains only its own optimization year, so each solution pass is myopic.

2.4 Representative days and weather year

The year is represented by 40 representative days, selected separately for each optimization year from the hourly load and renewable profiles of the 2023 weather year, so the number of weather years is one. Day selection uses one national binning region. Each region's contribution to the clustering features is weighted by REGION_BINNING_WEIGHT, whose single national value RIO allocates to zones in proportion to 2010 household counts; the export zone carries zero weight. The clustering features and their weights are net load (0.5), a polynomial fit of the net-load shape (0.1), maximum net load (0.3), upward net-load ramp (0.01), total over-generation (0.1), and the sine and cosine of day of year (0.05 each). Hydro output is netted from load rather than used as a separate feature, and the renewable portfolios used to compute net load take at most 80% of their energy from one resource. The representative-day weights sum to 365 days in each year, and the four cases use the same representative days.

The reliability-critical percentile is zero, so every representative day is reliability-critical and carries the planning reserve constraint. Capacity-reservation windows are monthly.

2.5 Units, currency, and discounting

RIO works in gigawatt-hours for energy, hectotonnes for mass, liters for volume, kilometers for distance, and degrees Fahrenheit for temperature, in US dollars of 2024. Costs are discounted at a real rate of 3% per year from the base year 2026, the first optimization year. Demand-side costs are converted from the EP basis (US dollars of 2025) to 2024 dollars.

2.6 Solution

Each pass is a linear program, built with the linopy modelling framework and solved with the MOSEK interior-point optimizer without basis identification (crossover), with a relative gap tolerance of 5×10^{-4}. The penalty terms of the objective are set as follows.

Penalty	Value
Unserved energy (value of lost load)	20,000 US dollars per MWh
Unserved material blends	9,999 US dollars per tonne
Over-generation	100 US dollars per MWh
Hydro budget violation	100 US dollars per MWh
Retirement before the minimum retirement year	5,000 US dollars per kW

2.7 Constraints and features

Constraint or feature	Setting
Planning reserve margin	On (margins in Section 3.12)
Operating reserves	Off
Primary annual emissions cap over the United States	On; finite from 2035 in the alternative cap case only

Constraint or feature	Setting
Secondary emissions cap, cumulative emissions cap, radiative-forcing limit	Off
Per-gas emissions price	On; nonzero in the carbon price case only
Sectoral carbon-intensity standards	On; finite ceilings in the emissions intensity cap case only
Sectoral absolute emissions standards	On, with no finite ceiling in any case
Clean-energy standards, primary and secondary	Off
Hourly clean-energy matching, primary and secondary	Off
Land-use constraints, primary and secondary	Off
Unit commitment (thermal operating states)	Off: no generator carries a minimum load factor, start cost, or minimum up and down time, and generation is continuous between its hourly bounds
Transmission	Zonal transport representation; no nodal network or power-flow constraints
Hydro energy	Fixed daily energy budgets on representative days, which may be shifted by up to 15 days earlier or later, with a penalty on budget violation
Repower eligibility window	Five years
Symmetric decline limit on annual build	Off
Penalty on filling cumulative-cap bins	Off
Growth penalties	On (values in Section 3.1)
Commodity non-decrease constraint	Applies to geologic CO_2 sequestration
Load shifting	Off; the database supplies no flexible-load data

No electricity transmission connection carries an emission rate, so the transmission term of the emissions balance is zero.

2.8 Demand mode

Demand optimization is on for demand technologies and for efficiency and fuel-switching measures (mode (b) of the *RIO Model* document). Of the 85 active demand subsectors, 17 are optimized: ten building end uses (residential and commercial space heating, water heating, and air conditioning; residential clothes washing and drying; residential and commercial cooking) and seven transport end uses (passenger car, passenger truck, medium-duty truck, heavy-duty truck, school bus, transit bus, and other bus). The optimized subsectors contain 95 demand groups and 123 demand technologies, plus 8 cooling technologies linked one to one to heat-pump heating technologies, giving 18,120 technology–zone–vintage sales combinations. The other subsectors, including all industrial end uses, pass final energy demand to RIO, which can modify it only through efficiency and fuel-switching measures.

2.9 Emission gas weights

GAS_GWP gives CO_2 a weight of 1 and gives methane, methane subject to a fee, nitrous oxide, fluorinated gases, and hydrogen a weight of 0, in every zone and year. Every cap, price, and standard in the runs therefore applies to CO_2 emissions. Upstream methane rates and exogenous non-CO_2 emissions are carried in the data and tracked, and they

do not count toward any instrument.

2.10 Hydrocarbon supply settings

Setting	Value
Source run	NEMS Hydrocarbon Supply Module in standalone mode against the Annual Energy Outlook 2026 reference case, 2024 to 2050
First-year annual potential of new onshore Lower 48 supply	Reference-case 2026 drilling times 1.10 for gas and 1.60 for oil; legacy, offshore, Alaska, and Canadian supply are not scaled
Bin edges	19 breakeven-cost edges from 1 to 10 US dollars per MMBtu for gas; 15 edges from 20 to 200 US dollars per barrel for oil
Gas bin ceiling	Bins above 10 US dollars per MMBtu (2025 dollars) are excluded
Intra-bin tranche data	None; cost is uniform within each bin, and resource exhaustion is governed by the cumulative limit and the drilling constraints
Project hurdle rate	16.58% (NEMS project discount rate)
Drilling groups	One rig group for each of the seven HSM regions, a national rig group, and one footage group for each HSM region
Drilling-pace segments	20 equal-width segments per play; pace exponent clipped to 0.5 to 2; denominator of the pace premium floored at 0.10 for bins with persistence above 0.9
Surge ceiling and ramp period	2 and five years (NEMS values)
Electrified extraction and processing	Electricity input equal to one third of the energy of the produced gas it displaces as field fuel
Liquefied natural gas exports	Bins up to three times the AEO export volume
Refined product exports	Fixed at the AEO volume

The carbon contents of the extraction-and-processing output carriers are 53.06 kg CO_2 per MMBtu for pipeline gas (domestic and export), 61.24 kg CO_2 per MMBtu for hydrocarbon gas liquids, and 74.60 kg CO_2 per MMBtu for crude oil (domestic and export). The wellhead carbon charge of each commodity exceeds the 53.06 kg CO_2 per MMBtu of pure methane by an amount that rises with the liquids and crude share. Across shale gas commodities and zones the wellhead carbon charge ranges from 53.1 to 63.7 kg CO_2 per MMBtu of raw wellhead energy.

The energy share of pipeline gas in shale gas extraction and processing falls from 0.99 in the driest model zone to 0.70 in the wettest, with the balance moving to liquids and crude (Table 1). In west Texas pipeline gas takes 0.705 of the energy and 0.651 of the carbon, while crude takes 0.145 of the energy and 0.189 of the carbon.

Table 1. Modal output split for shale gas extraction and processing, selected model zones, 2026 vintage. Energy shares are per unit of raw wellhead energy; carbon-weighted shares are those energy shares weighted by the carbon contents of the output carriers and renormalized.

Zone	Energy share: gas / HGL / crude	Slate CO_2 (kg per MMBtu)	Carbon-weighted share: gas / HGL / crude
Tennessee Valley (driest)	0.988 / 0.011 / 0.000	53.15	0.987 / 0.013 / 0.000

Zone	Energy share: gas / HGL / crude	Slate CO_2 (kg per MMBtu)	Carbon-weighted share: gas / HGL / crude
Ohio–Appalachia	0.833 / 0.138 / 0.029	54.81	0.807 / 0.154 / 0.039
Gulf South	0.885 / 0.062 / 0.052	54.70	0.859 / 0.070 / 0.072
West Texas (wettest)	0.705 / 0.150 / 0.145	57.41	0.651 / 0.160 / 0.189

2.11 Payback-acceptance curves

DEMAND_PAYBACK_CURVES gives, for each demand group of the optimized subsectors, the share of purchasers who accept each payback period. Acceptance distributions are taken from published sources where they exist, and no distributional form is imposed on them. Where a source gives discount rates, they are converted to payback thresholds by the annuity-factor relation at the median lifetime of the technologies in each subsector, taken from the EP stock characterization. Every demand group in the runs has a curve. Industrial subsectors carry no payback-acceptance curve.

Subsector group	Basis	Bins	Mean acceptable payback (years)	Source
Commercial space heating, air conditioning, water heating, cooking	NEMS Commercial Demand Module consumer time-preference segments by end use, converted from discount rates to payback thresholds	7	1.64 to 1.88	EIA, NEMS input input/cdm/kprem.txt (AEO 2026)
Heavy-duty trucks, transit bus	NEMS heavy-duty vehicle payback-acceptance shares by size class, used as published	6	3.34	EIA, NEMS input input/tdm/trnhdvx.xlsx, range PBACK_SHR (AEO 2026)
Medium-duty trucks (classes 3, 4, 5, and 6), school bus, other bus	NEMS heavy-duty vehicle payback-acceptance shares by size class, each class on its own NEMS size-class column, used as published	7	3.47 to 4.45	EIA, NEMS input input/tdm/trnhdvx.xlsx, range PBACK_SHR (AEO 2026)
Residential space heating, air conditioning, cooking, clothes washing, clothes drying	Lognormal, σ = 0.66, median from a 25% hurdle rate	10	4.78 to 4.89	EIA, *Assumptions to the AEO 2022*, Residential Demand Module, Table 2
Residential water heating	Lognormal, σ = 0.66, median from a 50% hurdle rate	10	2.42	EIA, *Assumptions to the AEO 2022*, Residential Demand Module, Table 2
Passenger car, passenger truck	Lognormal, σ = 0.66, median of 3 years	10	3.73	Greene (2010), reporting Greene, German, and Delucchi (2009)

The commercial curves have seven segments with proportions summing to one. One segment has a discount rate above 1,000%, equivalent to a payback threshold near zero, and represents purchasers who do not adopt on economics; it is retained as published. Because the segments are discrete, the curves step and are not smoothed. EIA derives the segments from Koomey (1990) and Decision Analysis Corporation of Virginia and Science Applications International Corporation (1992), aligned to the return-on-investment categories of the Johnson Controls Energy Efficiency Indicator surveys and supplemented by a 2014 Navigant Consulting webinar and the Institute of Real Estate Management (2017) survey; they are documented in Appendix E of the EIA (2025) Commercial Demand Module documentation.

The heavy-duty vehicle curves have six or seven published payback-year thresholds, including the stated seven-year cutoff beyond which no fleet purchases new equipment.

The residential hurdle rates are the approximate rates for the electric option in the *Assumptions to the AEO 2022*, the most recent edition that publishes them. Cooking, clothes washing, and clothes drying, which have no published rate, use the median published residential rate. The rates are calibrated to observed shares for efficiency upgrades within a fuel, and they lie below the range of implicit discount rates reported in the literature for residential equipment (Train, 1985; Schleich et al., 2016). The passenger vehicle median is the loss-aversion result reported in Greene (2010), which finds that consumers behave as if requiring about a three-year simple payback for fuel economy.

The lognormal dispersion $\sigma = 0.66$ is estimated from the two published distributions ($\sigma = 0.643$ for the commercial segments; 0.63, 0.68, and 0.81 across heavy-duty size classes). The fitted family reproduces the published heavy-duty bins with a mean absolute error of 3.6 to 5.1 percentage points per bin. The lognormal is closed under reciprocal, so one assumption serves both the discount-rate and the payback-year forms. It is discretized into ten equal-probability bins valued at the conditional mean of each quantile interval, which reproduces the distribution mean and requires no open-ended top bin. Each published central value is read as the median of the distribution; the mean exceeds the median by a factor of $\exp(\sigma^2/2) = 1.24$.

3 Data sources and derivation by domain

3.1 Electricity supply technologies

Catalog. NEW_TECH_MAIN defines the new-build technologies. The runs model 114, typed by operating representation. Each row assigns the technology to build-constraint groups, reporting groups, a temporal shape, and a timestep.

Type	Count	Technologies
Thermal	14	Gas combined cycle with and without carbon capture, gas combustion turbine, coal with carbon capture, carbon-capture retrofits of existing coal and gas plants, small modular reactor steam turbine generators (new and retrofit), a mothballed-generator option, and five industrial load-shedding tiers
Fixed	21	Variable renewables with hourly profiles: onshore wind, fixed-bottom and floating offshore wind, utility-scale and rooftop solar, enhanced geothermal, and upgrades to existing hydropower

Type	Count	Technologies
Electric storage	1	Lithium-ion battery
Blend storage	4	Hydrogen storage in salt caverns and in underground pipes, small modular reactor thermal energy storage, and thermal energy storage
Hydro	1	Powering of non-powered dams
Conversion	73	Technologies that convert one carrier into another: fuels, hydrogen, industrial materials including clinker and cement, process heat, nuclear heat, LNG liquefaction, and oil and gas extraction

Cost and performance of generators and batteries. Capital cost, fixed and variable operating cost, heat rate, and construction and lifetime parameters for wind, solar, gas-fired generation, coal and gas generation with carbon capture, enhanced geothermal, and lithium-ion storage come from the NREL Annual Technology Baseline 2024 (ATB 2024), in 2022 dollars. The ATB cases and configurations used are:

Technology	ATB 2024 case
Onshore wind, utility-scale solar	Moderate, NREL limited-access siting
Fixed-bottom and floating offshore wind	Moderate
Rooftop solar, gas combustion turbine	Moderate
Gas combined cycle	Moderate, 2-on-1 H-frame
Gas combined cycle with carbon capture	Moderate, 2-on-1 H-frame, 95% capture
Coal with carbon capture	Moderate, 95% capture
Carbon-capture retrofit of coal; of gas	Moderate, 90% capture; Moderate, H-class 90% capture
Lithium-ion battery	Moderate
Enhanced geothermal	Moderate, combined with the NREL geothermal supply curves (Section 3.2)

Wind, solar, and offshore wind costs vary by resource class and by us_eer_w_state region because they are built from the ATB 2024 supply curves (Section 3.2). Small modular reactors are represented as a reactor (a conversion technology that produces nuclear heat), a steam turbine generator, and thermal energy storage. Reactor and turbine costs come from a peer-reviewed study recorded in the source column, in 2021 dollars; the storage cost comes from the IRENA thermal energy storage outlook.

Financing. TECH_FINANCING_MULTIPLIER holds technology-specific cost of capital from ATB 2024 for the supply-curve technologies (for the 2021 vintage, about 4.7% for onshore wind, 4.9% for offshore wind, and 3.9% for utility-scale solar). Other technologies carry a cost of capital in their capital cost rows. TECH_COST_MULTIPLIER holds state-level capital cost multipliers from NREL ReEDS for onshore wind (1.0 to 2.0); the multiplier for every other technology is 1.

Operating characteristics. For dispatchable generators:

Parameter	Table	Source
Forced, planned, and maintenance outage rates	TECH_OUTAGE	NERC Generating Availability Data System, *Generating Unit Statistical Brochure 4*, 2019–2023, all units reporting; the forced outage rate is the equivalent forced outage rate for production cost (EFOR)
Ramp rate (fraction of capacity per minute) and minimum stable load	TECH_RAMP, NEW_TECH_P_MIN	By assumption, by technology type

Capacity credit. TECH_DEPENDABILITY holds the fraction of capacity counted toward planning reserves, either as a deemed value or as a performance multiplier on modeled output. As performance multipliers, new onshore wind is 0.7, new offshore wind, existing wind, and rooftop solar 0.8, new utility-scale solar 0.9, existing utility-scale solar 0.95, lithium-ion storage 1.0, and enhanced geothermal 1.15. As deemed values, gas-fired, nuclear, hydro, and other dispatchable generators are 0.93 to 0.95, coal-fired plants 0.84 to 0.93, and existing demand response 0.90. The industrial load-shedding tiers are 0.90, based on the performance of firm industrial interruptible programs in organized capacity markets and the FERC 2023 assessment of demand response.

Interconnection. NEW_TECH_TX_COST holds the cost of connecting new plants to the network. For onshore wind, utility-scale solar, and offshore wind, it is the spur-line cost of each supply-curve site from the ATB 2024 supply curves (2022 dollars per kW). For enhanced geothermal it is the site interconnection cost from the NREL geothermal supply curves combined with ATB 2024. For gas-fired generators and small modular reactor turbines it is a generic network-upgrade cost from the Lawrence Berkeley National Laboratory interconnection cost studies.

Build limits. Three tables bound the rate of new construction:

- NEW_TECH_ANNUAL_BUILD_CAP sets minimum and maximum additions per year by group. Near-term limits by zone come from planned generators in the EIA Form 860M monthly generator inventory (read through the PUDL database), by technology group, county, and expected online year. The table also holds the LNG liquefaction build limit (Section 3.6), a national limit on biofuel plant additions from EIA and Alternative Fuels Data Center capacity history, national limits for 2025 to 2032 on hydrogen production by reforming with carbon capture and by electrolysis, national limits on carbon capture additions, national limits on small modular reactor additions, which allow none before 2031, and zonal limits on rooftop solar additions in 2025. The hydrogen, carbon capture, reactor, and rooftop solar limits are set by assumption. Several annual limits rise with the preceding year's build at a compound rate given in the cagr column.
- CUMULATIVE_BUILD_CAP sets minimum and maximum cumulative capacity by group and zone. It holds the resource potential of the supply-curve technologies (Section 3.2), the potential of new hydropower, industrial geothermal heat, rooftop solar, and industrial demand response, and caps on groups of industrial and hydrogen technologies.
- NEW_TECH_BUILD_GROWTH_PENALTY assigns a cost penalty, by group, to growth in annual additions above the preceding period. National groups for carbon-capture power, hydrogen technologies, nuclear, onshore and offshore wind, utility-scale solar, advanced fuels, geothermal, gas turbines, and industrial demand response carry 0.15, and the national hydro group carries 0.10. Zonal groups carry 0.05, except data centers at 0.10.

NEW_TECH_AVAILABILITY sets the first year and zones in which each technology may be built.

3.2 Renewable resource potential and profiles

Onshore wind and utility-scale solar. Resource potential, capacity factor, capital cost, and spur-line cost come from the NREL reV supply curves published with ATB 2024. The supply-curve sites are grouped into resource classes (onshore wind|n, utility-scale solar pv|n) within each us_eer_w_state region, giving potential in CUMULATIVE_BUILD_CAP, capacity factor in NEW_TECH_CAPACITY_FACTOR, and interconnection cost in NEW_TECH_TX_COST for each class and region. The runs include three onshore wind classes and two utility-scale solar classes, under NREL's limited-access siting case.

Offshore wind. Fixed-bottom offshore wind has four resource classes and floating offshore wind three. Potential, capacity factor, and cost come from ATB 2024.

Geothermal. Enhanced geothermal systems (geothermal egs|3 to |7) take potential, capital cost, fixed operating cost, and interconnection cost from the NREL *United States Geothermal Supply Curves 2024* combined with the ATB 2024 Moderate case, in 2022 dollars. Their hourly output profile depends on ambient temperature and is the profile for an extraction temperature of 175 °C. Geothermal heat for industrial use (geothermal boiler|2 and |3) carries potential and cost set by assumption.

Hydropower. Powering of non-powered dams and upgrades to existing hydro take potential and capital cost from the ReEDS 2.0 hydropower supply curves (2019), in 2015 dollars. The capacity factor of non-powered dams comes from ReEDS; the capacity factor of upgrades is the capacity-weighted state average of existing large hydro plants, computed from EIA-923 generation (Section 3.3). Monthly energy budgets and minimum and maximum output for dispatchable hydro come from RectifHyd v1, a plant-level monthly hydropower dataset.

Rooftop solar. Residential, commercial, and productive-sector rooftop solar take potential and adoption bounds from the mid case of the NREL *2020 Standard Scenarios* (Cole et al., 2020), allocated 43% to residential, 50% to commercial, and 7% to productive-sector rooftops. New rooftop solar capacity factors come from ATB 2021.

Hourly profiles. Wind and solar profiles are normalized hourly capacity factors by ReEDS balancing area for the 2023 weather year: high wind-speed onshore wind (new plants), low wind-speed onshore wind (existing plants), fixed-bottom and floating offshore wind, single-axis tracking utility-scale solar, and south-facing rooftop solar. Each technology refers to its profile through the shape column of NEW_TECH_MAIN or EXISTING_TECH_MAIN; dispatchable generators and most conversion technologies use a flat profile. SHAPE_META lists the profiles with their type (weather-date indexed or time-slice indexed), their native geography, and their time zone. The demand profiles listed in SHAPE_META are written by EP. The availability profile for industrial demand response is the EP industrial machine-drive load shape.

Day clustering weights. CES_BINNING_WEIGHT weights the renewable profiles used when RIO selects representative days, and REGION_BINNING_WEIGHT weights the regions (Section 2.4).

3.3 Existing generating fleet

Generators. The existing fleet is built from the EIA Form 860 generator inventory and EIA Form 923 generation and fuel data, read through the PUDL database (Catalyst Cooperative). Generators are aggregated to plant and technology and assigned to counties. EXISTING_TECH_MAIN holds thermal, fixed, hydro, storage, and conversion plants with capacity, storage energy, and minimum and maximum output; the schedule table determines when each unit is in service. Gas combined cycle, gas combustion turbine, gas steam turbine, and pulverized coal plants are each divided into five classes (suffixes |1 to |5). Industrial combined heat and power plants are included, because the database's

industrial electricity demand is gross of self-generation; their heat rates carry a credit for co-produced steam. Imports from Québec are represented as existing hydro capacity in the New England and New York zones, with expected annual energy from contracted and historical deliveries.

Schedule. EXISTING_TECH_SCHEDULE gives each plant an operating year, a minimum retirement year (before which the model may not retire it), and a retirement year. Retirement years come from actual retirements in EIA-860, from planned retirements in EIA-860, or, where neither applies, from a standard lifetime by technology type. Plants under construction or planned in the EIA-860M inventory (July 2025 edition) enter with their expected online year.

Operation. EXISTING_TECH_CAPACITY_FACTOR holds minimum and maximum annual capacity factors by plant, derived from EIA-923 generation, with technology-type defaults where plant data are missing. The maximum annual capacity factor of fossil-fuelled and biomass generators is 0.75 and that of nuclear plants 0.95; combined heat and power plants carry their own measured values. EXISTING_TECH_EFFICIENCY_MODAL holds heat rates by plant and operating mode from the 2022–2024 average of EIA-923 fuel consumption and generation; where plant data are missing, it uses tested heat rates from the EIA *Electric Power Annual* (Table 8.2, 2024) or the capacity-weighted median of measured units of the same technology. EXISTING_TECH_EFFICIENCY holds single-mode efficiencies for conversion facilities and plants without modal data. Plant records are matched between datasets on EIA plant (ORIS) codes rather than on names.

Demand response. Existing demand response is represented as three technologies (residential, commercial, industrial) with capacity by state equal to potential peak demand savings reported on EIA Form 861 for 2022: 9,039 MW residential, 6,545 MW commercial, and 14,864 MW industrial, 30,448 MW in total. Fixed operating cost by state and sector is total reported program cost divided by potential capacity, in 2022 dollars. Each may be called for up to 20 hours per year (maximum capacity factor 0.0023). Outage rates are zero.

3.4 Electric transmission

RIO represents interzonal electricity transfer as corridors between pairs of model zones. The corridor set is 52 zone pairs, each with an existing corridor (electricity). On 42 of these pairs, expansion is offered as up to three new-line cost bins (electricity new line, with n from 1 to 3), 107 bins in all, of which 91 may be built. The existing transfer capability and the new-line bins come from internal analysis: the first optimization year of a nodal RIO run on a DC power-flow representation of the transmission network. In that analysis each bin is a set of network upgrades; a bin's capability is the net transfer capability the upgrades add across the corridor's zone boundary, and its cost is the share of the upgrade cost that corresponds to that capability.

Quantity	Table	Derivation
Existing transfer capability	TRANSMISSION_SCHEDULE	Transfer capability of each corridor by direction in GW, from the internal analysis, held constant over the horizon. Summed over corridors, 197 GW in the from-to-to direction and 199 GW in the reverse direction; 0 to 14.3 GW per corridor and direction.

Quantity	Table	Derivation
Losses	TRANSMISSION_LOSSES	ReEDS per-mile AC loss factor times corridor distance; for the five DC corridors, the ReEDS per-mile DC loss factor plus 0.7% at each converter. For the corridors that connect new_york_city to mid_atlantic and southern_new_england, the corridor distance is estimated. Range 1.4% to 9.2%. New-line bins carry the losses of the corridor they expand.
Hurdle rate	TRANSMISSION_HURDLE	ReEDS intra-regional hurdle of 2.92 $/MWh (2004 dollars), converted to 4.62 $/MWh in 2024 dollars, on existing corridors and new-line bins
Capital cost of new-line bins	TRANSMISSION_CAPITAL_COST	Upgrade cost of each bin from the internal analysis, in 2025 dollars per kW; 75-year life; 50-year book life; 5% real cost of capital; five-year construction time. Over the buildable bins, mean 480 $/kW, median 257 $/kW, range 3 to 5,891 $/kW; the median is 133 $/kW for bin 1, 317 $/kW for bin 2, and 626 $/kW for bin 3.
Fixed operating cost	TRANSMISSION_FIXED_OM	Fixed operating cost of the upgrades in each bin from the internal analysis, in 2025 dollars per kW-year; about 1% of capital cost per year (0.3% to 2.4%)
Expansion potential	TRANSMISSION_POTENTIAL	The capability each bin adds in the internal analysis, as a cumulative limit that applies from the first model year: 0.25 to 6.6 GW per bin, 0.25 to 7.5 GW per corridor, and 104 GW over the buildable bins
Availability	TRANSMISSION_AVAILABILITY	The 91 buildable bins may be built from 2030. The other 16 bins carry no availability and cannot be built. Existing corridors cannot be expanded.

The cost of capital on transmission is a real rate because the capital cost is in real dollars.

3.5 Fuels and commodities

3.5.1 Domestic oil and gas supply

Domestic oil and gas supply is represented by commodities whose cost, potential, decline, and drilling parameters are derived from the Hydrocarbon Supply Module (HSM) of the EIA National Energy Modeling System (NEMS). The module was run in standalone mode against the Annual Energy Outlook 2026 reference case for 2024 to 2050, and the database builder reads its play-level intermediate results and the NEMS restart file. Play inventories, per-well production profiles, drilling and facility costs, dry-hole rates, royalty and severance rates, technology improvement rates, rig and footage regressions, and drilling-pace parameters are NEMS inputs. All costs are expressed in 2025 dollars, converted from the NEMS 1987-dollar basis with the NEMS chain-weighted GDP deflator read from the

restart file (a factor of 2.426 from 1987 to 2025). The supply representation, including the breakeven equation, is given in Section 6 of the *RIO Model* document, and the settings used in the runs in Section 2.10; this section describes the data.

Commodities. Shale gas and tight oil are disaggregated into named plays following the NEMS play maps, with new drilling (Marcellus, Utica, Haynesville, Eagle Ford, Permian, Woodford, and other shale gas; Wolfcamp, Spraberry, Bakken, Eagle Ford, Niobrara, Austin Chalk, Avalon–Bone Spring, Woodford, and other tight oil). Conventional gas, conventional oil, and coalbed methane are represented at type level. Committed supply from the Gulf of Mexico offshore, Alaska, and Canada is represented by separate commodities. Each of these plays and types has a legacy counterpart for production from wells drilled through 2025, and the Barnett, Fayetteville, Antrim, and Bakken gas plays and the Utica oil play are represented by legacy production only.

Bins. Within each NEMS producing district, the play slots of a commodity are grouped on fixed breakeven-cost edges (19 edges from $1 to $10 per MMBtu for gas, dense at the low end; 15 edges from $20 to $200 per barrel for oil), and the groups are then renumbered so that each distinct cost receives one bin index per commodity, ascending in cost, across all districts. A bin index therefore denotes the same cost in every district, and aggregation from districts to model zones sums potential within a single cost level. Gas bins with a total wellhead cost above $10/MMBtu (2025 dollars) are dropped as sub-economic. Oil bins carry no ceiling.

Breakeven cost. COMMODITY_COST gives each bin the after-tax breakeven price at which the net present value of drilling a well is zero, following the NEMS project cash flow:

- Capital includes drilling cost, facility cost, and the expected dry-hole cost per well drilled.
- The discount rate is the NEMS project hurdle rate, computed from the restart file as a real weighted average cost of capital plus an extra-risk premium and a required return (16.58% for AEO 2026).
- Severance and production taxes are state-specific, from the NEMS state tax input file. Income tax combines the state corporate rate and the 21% federal rate with state tax deductible. Intangible drilling cost and dry holes are expensed in the first year, and the tangible share is depreciated on a seven-year schedule.
- Costs decline by year at the NEMS technology improvement rates for drilling cost, facility and operating cost, and per-well recovery.
- Costs are expressed per MMBtu of total wellhead output, with the value of co-produced liquids credited for gas plays. Gas volumes are converted at 1 Mcf = 1 MMBtu.

Legacy commodities and committed Alaska oil carry zero marginal cost. Offshore supply is priced at the NEMS AEO 2026 restart wellhead price, Canadian gas at the NEMS AEO 2026 Canadian wellhead price, and Alaska gas at the NEMS AEO 2026 restart wellhead price for its district.

Potential. COMMODITY_POTENTIAL holds several potential types for each commodity and bin:

Type	Content
cumulative	Remaining resource: undrilled wells entering 2026 (core and degraded infill locations) times the per-well recovery over 40 years, in MMBtu of total wellhead output

Type	Content
annual	For legacy commodities, declining production from existing wells. For new supply in 2026, production from HSM 2026 drilling, scaled by the first-year factors of Section 2.10. For new supply after 2026, the drilling-capacity ceiling (drillable wells per year times first-year production per well), doubled to leave headroom for price-responsive drilling
pace_plateau	The NEMS drilling plateau, the minimum of the maximum drilling rate and the maximum annual fraction of remaining wells, times first-year production
drill_decline_plateau, drill_decline_slope	A linear approximation, tangent at each play's current position, of the NEMS relationship between cumulative wells drilled and the number of wells available to drill next

COMMODITY_TRAJECTORY gives the ratio of second-year to first-year production per well for each bin, which carries the decline of production from wells drilled in earlier years.

Drilling capacity. COMMODITY_GROUP_EXTRACTION holds the annual drilling capacity of fifteen groups: a rig group for each of the seven HSM regions, a national rig group, and a footage group for each HSM region. The rig capacity is computed from the NEMS rig-count regression against the Brent price in 1987 dollars, with the NEMS wells-per-rig values. A 10% allowance for rig movement between regions applies to regional limits only. Wells drilled to maintain production from committed projects are netted from the capacity. In 2026, regions whose regression result falls below the drilling HSM itself projects receive that drilling as a floor. COMMODITY_GROUP_EXTRACTION_MEMBERS gives the capacity each MMBtu of each commodity bin consumes, including the dry holes drilled per successful well.

Drilling-pace premiums. COMMODITY_COST_PACE holds premiums that represent the NEMS drilling-pace response to price, in which drilling rises above its plateau rate as price rises above a base price. The annual potential of each play is divided into 20 equal segments for each year from 2027 to 2050, and each segment carries a premium equal to the price at which NEMS would drill at that pace, less the bin's cost. The base price is the NEMS base gas price of $2.20/Mcf in 1987 dollars ($5.34/MMBtu in 2025 dollars) for gas plays and the NEMS per-play base oil price for oil plays. The response exponent depends on well type, following the NEMS rules. No pace premium applies in 2026.

Extraction and processing. Produced hydrocarbons pass through extraction-and-processing conversion technologies, one per resource type (shale gas, conventional gas, coalbed methane, tight oil, conventional oil), in three variants: base, electrified, and with carbon capture on the acid-gas stream (coalbed methane has no capture variant). NEW_TECH_EFFICIENCY_MODAL gives each variant its district-specific output split among pipeline gas, hydrocarbon gas liquids (as the hpgl blend), and crude, and its field fuel or electricity use, from HSM district yields and gas-to-oil ratios, with electrified energy use from ERCOT and S&P Global 2023 data (Table 1 gives the split for shale gas in selected zones). Capital and operating costs come from HSM and EIA gas processing plant economics. TECH_RATIO_CONSTRAINT bounds the share of each resource type processed by electrified variants, by zone, from ERCOT, S&P Global, East Daley, Enverus, NRDC, utility disclosures, and California Geologic Energy Management Division data. Raw hydrocarbon gas liquids (the hpgl blend) are converted to the hgl blend by a fractionation technology restricted to Texas and Louisiana, where most US fractionation capacity sits. Its variable cost of $1.15/MMBtu combines a fractionation fee sized to the observed merchant fee of about $0.08/gal with a production-weighted national average transport cost from basin to the Gulf Coast of $0.70/MMBtu.

CO_2 content. COMMODITY_EMISSIONS gives each commodity bin a CO_2 content, weighted by the composition of the wellhead stream in each district, using the carbon contents of Section 2.10. TECH_CONVERSION_EMISSIONS assigns the carbon content of each output blend of the extraction technologies.

3.5.2 Coal, uranium, and petroleum imports

Coal. The delivered price of thermal coal is set by state from EIA-923 Schedule 2 fuel receipts (2022–2024, read through PUDL), as a heat-weighted average including PUDL's filled values for redacted costs. Each year's costs are deflated to 2025 dollars before averaging. States with thin coverage fall back to their census division average. Montana, where all EIA-923 costs are redacted, is anchored to the FERC Form 1 fuel cost of its principal coal plant. Each state value is projected to 2050 with the AEO 2026 electric-power coal price trajectory from the NEMS restart file. Because the price is a delivered price, coal carries no separate delivery cost. Coking coal is priced from AEO 2023.

Petroleum imports. Unfinished oil import is priced at 0.50 times the AEO 2026 real Brent price, which keeps it inframarginal within its annual potential. Refined product import is priced at the Brent price per MMBtu (at 5.8 MMBtu per barrel) times 1.2208. Annual import potentials come from AEO 2026. Blending component import carries a potential and no cost. Prices use the AEO real-dollar Brent series.

Uranium. Uranium is a commodity with zero cost.

3.5.3 Biomass and bio-based feedstocks

Billion-Ton 2023 feedstocks. Potential and price for 53 feedstocks (agricultural residues, energy crops, forest residues and small-diameter trees, municipal and food wastes, landfill gas, manures, sludge, animal fats and greases, and intermediate oilseeds) come from the DOE *2023 Billion-Ton Report* (BT23) data portal. Potential is given by county and price bin for the BT23 mature-market low scenario. Price bins carry the BT23 price points in dollars per MMBtu (dollars per pound for oilseeds and for fats, oils, and greases); 9 cents per pound is added to the oilseed prices for transport.

Existing biomass and corn. Existing herbaceous, woody, and waste biomass potentials by state come from the 2016 Billion-Ton Report. Corn for ethanol is priced at $6/MMBtu and limited by a state potential adapted from the Princeton *Net-Zero America* study.

Fats, oils, and greases. Vegetable oils (soybean, canola, and corn oil), animal fats (tallow, white grease, and poultry fat), yellow grease, and other fats carry potentials by state, which are set by assumption. Their prices come from USDA Agricultural Marketing Service reports and commodity price series. COMMODITY_DELIVERY_COST gives their delivery cost between states.

Forestry residues. A Pacific Northwest forestry residue supply curve in six steps by county comes from the Lawrence Livermore National Laboratory *Roads to Removal* study.

Municipal solid waste. The municipal solid waste blend is supplied by paper and paperboard, textiles, urban wood, yard waste, and existing waste biomass. Plastics and rubber and leather are not admitted to the blend. The blend carries no delivery cost in any sector.

3.5.4 CO_2 storage

Geologic storage. Geologic CO_2 storage is a commodity with a 20-bin cost curve and annual potential by state. Fifteen saline bins take their cost from the FE/NETL CO_2 Saline Storage Cost Model (2017), at 15.9 to 180.4 US dollars per tonne in 2016 dollars. One offshore bin is adapted from the Princeton *Net-Zero America* storage base case. The

four bins associated with enhanced oil recovery carry zero potential, because CO_2 used for enhanced oil recovery is accounted through the separate eor co2 sequestration commodity. COMMODITY_DELIVERY_COST gives the cost of moving captured CO_2 from each state to storage in another state, and COMMODITY_ELIGIBILITY lists the permitted state pairs.

3.5.5 Iron ore and scrap

Iron ore and iron and steel scrap are commodities priced from historical market data, with a national annual potential for scrap.

3.6 Natural gas pipelines, storage, and LNG

Pipeline network. Interzonal gas transport is represented as directional corridors between model zones, built from public geospatial and regulatory data in seven stages:

1. Normalize PHMSA natural gas transmission pipeline segments.
2. Intersect segments with Census county polygons.
3. Attach operators and FERC Form 2 system capacities through an operator crosswalk.
4. Attribute capacity to counties, using Weymouth-equation estimates where pipe attributes allow and segment length otherwise, with interstate pipelines weighted 15 times intrastate pipelines in the length-based method.
5. Build the interzonal arc graph.
6. Assign EIA Form 191 underground storage fields to counties.
7. Aggregate to model zones.

The capacity of each zone-to-zone corridor comes from two sources. Where a zone boundary coincides with a state boundary, EIA state-to-state pipeline capacity (certificated capacity by operator at each state crossing) is used. Where both zones lie in one state, or EIA data are absent, the FERC Form 2 system capacity of each operator is scaled by the operator's ratio of EIA crossing capacity to FERC system capacity (median about 0.37). The states on each side of a crossing are identified geometrically, by clipping each segment to the zone polygons and locating the transition point. TRANSMISSION_SCHEDULE gives each existing operator corridor its capacity in MMcf per day in the forward direction; the reverse direction is a separate corridor where flow is possible.

Corridor counts. TRANSMISSION_MAIN holds 336 existing gas corridors (by operator), 92 looping expansion corridors, and 71 border-crossing corridors to and from the export zone. Border capacities are based on EIA pipeline imports and exports by point of entry and exit (2023).

Tariffs. TRANSMISSION_HURDLE gives each existing corridor a piecewise-linear transport charge in utilization, with three anchor points per operator:

Utilization	Charge
0	FERC eTariff commodity rate (variable operating cost)
0.75	Total maximum filed rate (reservation plus commodity) at 100% load factor, which recovers the pipeline's cost of service
1.0	Cost of service times an operator-specific scarcity multiplier from 1.3 to 4.5, calibrated to capacity-release premiums in FERC Form 549D data (2015–2023); 2.0 where no operator value exists

Expansion. Looping (parallel pipe on an existing corridor) costs $10 per Dth/day per mile of route, derived from the INGAA average installed cost of about $7.5 million per mile for large-diameter pipe and a throughput of about 800,000 Dth/day, in 2023 dollars, with a five-year construction time, a 50-year life, a 5% real cost of capital, and 1% annual fixed operating cost. Route length is 1.25 times the area-weighted centroid distance between zones, computed from Census TIGER county polygons. Looping availability and potential depend on whether the corridor has a proposed project in the EIA natural gas pipeline projects table: proposed corridors may loop from 2032, up to the matched project capacity until 2040 and up to the existing corridor capacity afterward; corridors without a proposed project may loop from 2040.

Intrazonal delivery. The cost of moving gas from a zone's hub to consumers within the zone is in BLEND_DELIVERY_COST for the upstream sector, computed as 0.0025 $/Dth-mile times a haul distance equal to two-thirds of the radius of a circle with the zone's area (median about $0.26/MMBtu). Delivery margins to other sectors are in Section 3.9.

Storage. Existing underground gas storage (251 facilities, by county) comes from EIA underground storage reports (Form EIA-191) and PHMSA data.

LNG export terminals. LNG liquefaction capacity is assembled from a facility roster consistent with AEO 2026, using FERC LNG facility data, DOE export authorizations, and developer reports. The ten facilities operating or under construction (17.32 TBtu/day of capacity) are existing technologies; of these, the Kenai facility in Alaska (0.20 TBtu/day) carries a retirement year of 2015, so 17.12 TBtu/day is in service from 2026. Facilities that have not reached construction are not in the existing fleet. Facilities with a final investment decision (6.03 TBtu/day) enter as minimum annual builds in their announced years, set at 0.99 of announced capacity. Further liquefaction is an economic new build. Liquefaction capital cost for new build is $500/kW (2025 dollars), consistent with US Gulf Coast greenfield costs of $800–1,000 per tonne per year of capacity. All LNG technologies carry a fixed capacity factor of 0.90 (equal minimum and maximum), centered on the utilization implied by AEO 2026. New liquefaction may be built only in counties that host an operating or under-construction terminal. The annual build limit follows the announced project schedule through 2030 and 3.0 TBtu/day per year afterward, the fastest sustained historical rate. Liquefaction variable cost is the LNG delivery cost; an electric-drive variant is available.

LNG import terminals. Existing LNG import capacity comprises four terminals from FERC LNG import terminal data and one import facility in Hawaii.

3.7 Hydrogen and CO_2 pipelines

New hydrogen and CO_2 pipeline corridors (51 each) connect the same zone pairs as the gas network.

Parameter	Hydrogen	CO_2
Capital cost basis	FECM/NETL Hydrogen Pipeline Cost Model (H2_P_COM 2024): Parker-equation natural gas pipeline cost per mile for a 36-inch, 4.7 GW trunk line, times 1.10 for hydrogen service, escalated to 2024 dollars; about 0.66 $/kW-mile	FECM/NETL CO_2 Transport Cost Model (CO2_T_COM 2022): capital backed out of the model's break-even transport prices at 4.3 and 30 Mt/yr, escalated to 2024 dollars and interpolated to a 10 Mt/yr design flow; about 0.28 $ per tonne-per-year-mile
Fixed operating cost	1% of capital per year	2.5% of capital per year
Life	40 years	40 years
Distance	Zone centroid distance	Zone centroid distance

Parameter	Hydrogen	CO_2
Losses	New corridors 2.2% to 16.8% by distance; the existing pipeline 3%	None

Existing pipelines are the Air Products Gulf Coast hydrogen network and the Cortez, Sheep Mountain, Bravo, and Green CO_2 pipelines, with capacities from operator disclosures.

3.8 Exports and trade

Exports of crude oil, LNG, hydrocarbon gas liquids, and refined products are commodities of type accounting outflow: the model receives revenue for each unit delivered to the export blend, along a supply curve of volume against price.

Commodity	Curve	Bins	Benchmark price
oil export	Constant elasticity, elasticity 10	8, to three times the AEO volume	AEO 2026 real Brent
lng export	Constant elasticity, elasticity 4	7, to three times the AEO volume	NEMS LNG export price (free on board)
hgl export	Volume +10% and price −5% per bin	11	NEMS industrial feedstock price basket (Mont Belvieu)
refined product export	Fixed at the AEO volume	1	NEMS tax-free wholesale composite

Bin 1 of each curve is the AEO 2026 reference volume at the benchmark price. Pipeline gas exports to Canada and Mexico are a fixed volume from AEO 2026 in EXO_DEMAND, because they are bound by contracts and infrastructure. Fuel for domestic and international shipping, and the CO_2 from international bunkering, are also given in EXO_DEMAND.

3.9 Delivery costs and losses

BLEND_DELIVERY_COST holds the margin between the wholesale cost of a blend and the delivered cost to each consuming sector. Values derived from the NEMS AEO 2026 restart file are in 2025 dollars.

Blend	Geography	Source
Pipeline gas	Model zone by sector	NEMS sector gas prices less Henry Hub and electric-power prices, by census division mapped to zones; intrazonal transport for the upstream sector (Section 3.6)
Gasoline, diesel, jet fuel, fuel oil	Census division	NEMS petroleum distribution markups
Electricity	EMM region by sector	NEMS transmission and distribution cost components
Hydrocarbon gas liquids	National by sector	NEMS retail LPG prices
Hydrogen and liquid hydrogen	National	DOE hydrogen delivery technical targets (2016 dollars per gallon gasoline equivalent)

Blend	Geography	Source
Biomass, iron ore	National	By assumption; the upstream biomass margin is from the Billion-Ton Study
Municipal solid waste	National	Zero in every sector

BLEND_DELIVERY_COST_SHARES divides each delivery cost into shares recovered on energy flow, on base capacity, and on peak capacity. BLEND_LOSSES gives delivery losses by sector: electricity 3–4% to end-use sectors and 2.5% upstream; pipeline gas 3% (1% transportation); hydrogen 3%; liquid hydrogen 5%.

Delivery of conversion-technology output between states is priced in TECH_CONVERSION_DELIVERY_COST, from state centroid distances. For fractionated gas liquids the distance-based values are scaled to purity-product pipeline tariffs, and state-to-export values add a $0.50/MMBtu export terminal fee. Clinker is consumed in the zone that produces it. Cement may be supplied to any zone at a freight cost per tonne between states, in 2025 dollars: the lower of truck and rail cost over the great-circle distance between 2020 Census state centers of population times 1.22. Truck cost is $2.336 per mile with an empty return and a 25-short-ton payload (American Transportation Research Institute, 2025). Rail cost is a ton-weighted fit to the Surface Transportation Board 2022 Public Use Waybill Sample for cement (STCC 3241), scaled by 0.699 to the Class I average revenue per ton-mile of the Bureau of Transportation Statistics *National Transportation Statistics* (Table 3-21). The median freight cost between states is about $56 per tonne; delivery within a zone carries no cost.

3.10 Industrial materials and facilities

Existing facilities. Existing industrial conversion facilities are held in the existing technology tables:

Facility type	Entries	Capacity and method
Clinker production	4 census regions	100,068 kt per year in total. Kiln heat and electricity per tonne from the NEMS AEO 2026 industrial inputs (ironstlx.xlsx, Cement sheet); process CO_2 0.507 t per t clinker. Regional capacities by assumption. Maximum capacity factor 0.76.
Cement grinding (existing_cement - portland)	4 census regions	114,810 kt per year: clinker capacity divided by 0.8716 t of domestic clinker per t of cement (NEMS AEO 2026 Cement sheet: one less additives of 0.11721 and imported clinker of 0.01120). Two modes: ordinary portland cement (0.8716 t clinker and 58.6 kWh per t) and portland-limestone cement (0.7888 t clinker and 62.7 kWh per t), with portland-limestone cement limited to 75% of output. Maximum capacity factor 0.8.
Clinker kiln burners (coal, natural gas, petroleum coke, municipal solid waste)	4 census regions each	91.8, 73.5, 29.6, and 11.1 TBtu per year of kiln heat. Fuel split from the EIA *Manufacturing Energy Consumption Survey 2022* (Table 3.2, NAICS 327310) as transcribed in the NEMS AEO 2026 Cement sheet; 80% burner efficiency.

Facility type	Entries	Capacity and method
Lime production	4 census regions	16.2 Mt per year in total, by assumption; process CO_2 0.742 t per t lime.
Lime kiln burners (coal, natural gas, petroleum coke)	3 to 4 census regions each	42.6, 22.9, and 12.1 TBtu per year. Fuel split from EPA Greenhouse Gas Reporting Program 2023 Subpart C fuel-level CO_2 for NAICS 327410 facilities, converted to heat with the 40 CFR 98 Table C-1 factors.
Industrial boilers	421 county-fuel entries	EPA Greenhouse Gas Reporting Program Subpart C, 2022 reporting year: rated heat input by county and fuel, excluding electric utilities, cement, pulp and paper, iron and steel, fuel ethanol, waste combustors, and CHP units. Total 73.6 GW (pipeline gas 51.4, coal 7.4, distillate 6.4, biomass 4.9, petroleum coke 1.9, residual fuel oil 1.4, LPG 0.2). HHV efficiencies 72% to 82% by fuel.
Blast furnace and basic oxygen furnace	10 plants	39.9 Mt per year. Iron ore 1.391 t per t of crude steel, from the Agora Industry *Steel Transformation Cost Calculator* (2022).
Direct reduced iron	3 plants	6.4 Mt per year. Iron ore pellets 1.459 t per t, from the Agora Industry calculator.
Electric arc furnaces	71 plants	88.8 Mt per year.
Hot rolling, cold rolling, and continuous casting	81 plants each	123.6, 58.1, and 117.9 Mt per year. Energy intensities from the NEMS AEO 2026 steel inputs (2022 base technology shares). Each finishing unit operates as long as its plant's furnace.
Coke plants	13 counties	304.4 TBtu per year. Coking coal 1.560 and electricity 0.0044 MMBtu per MMBtu of coke, and net coke-oven gas output, from the NEMS AEO 2026 steel inputs.
Petroleum refineries, steam methane reformers, corn ethanol, biodiesel	126, 188, 206, and 32 entries	Facility rosters by county or state, compiled for this database: 19.0 million barrels of oil equivalent per day of refining, 10.6 Mt per year of hydrogen, 1,352 TBtu per year of ethanol, and 2.5 billion gallons per year of biodiesel.

Existing clinker, cement, and lime capacity enters in 2010, may not be retired before 2025, and has a retirement year of 2099.

Cement. Cement demand is given in tonnes of cement on the cement blend (Section 3.11). Three technologies supply the blend: existing cement grinding (existing_cement - portland), new portland cement grinding (cement - portland), and new limestone calcined clay cement (cement - limestone calcined clay). Each consumes clinker from the clinker blend and electricity.

	Existing cement grinding	New portland cement grinding	Limestone calcined clay cement
Product	Ordinary portland cement or portland-limestone cement (two modes)	Ordinary portland cement or portland-limestone cement (two modes)	LC3-50: 0.5 t clinker per t cement, with calcined clay, limestone, and gypsum made within the technology
Domestic clinker per t cement	0.8716 t (ordinary), 0.7888 t (portland-limestone)	0.8716 t (ordinary), 0.7888 t (portland-limestone)	0.4888 t
Other inputs per t cement	58.6 kWh (ordinary), 62.7 kWh (portland-limestone)	58.6 kWh (ordinary), 62.7 kWh (portland-limestone)	Clay calcined with 0.66 GJ of clinker kiln heat and 75 kWh of electricity, or calcined electrically with 259 kWh and no kiln heat (two modes)
Limit on portland-limestone share	75% of output	None	Not applicable
Capital cost	Not applicable	96.46 US dollars (2009) per t-year, the NEMS finish-grinding cost, times 1.5	180.73 US dollars (2022) per t-year times 1.5: the NEMS finish-grinding cost plus half the cost of a clay-calcining plant from DOE *Pathways to Commercial Liftoff: Low-Carbon Cement*
Fixed operating cost	None	None	10 euros (2021) per t-year
Variable operating cost	5.93 US dollars (2022) per t	5.93 US dollars (2022) per t	12.35 US dollars (2022) per t
Availability	114,810 kt per year in four census regions	From 2026, every zone except Alaska and Hawaii, no limit on capacity	From 2030, every zone except Alaska and Hawaii, no limit on capacity
Capacity factor	Maximum 0.8	Maximum 0.8	Maximum 0.8

The clinker ratios of portland cement are from the NEMS AEO 2026 Cement sheet: one less additives of 0.11721 and imported clinker of 0.01120, with imported clinker not represented. The variable operating cost of portland cement grinding is the NEMS finish-grinding operating cost of 2.35 US dollars (2022) per t plus the additives (limestone and gypsum) at 20 US dollars per t, weighted 25% ordinary and 75% portland-limestone cement. New cement technologies have a 40-year life, a three-year construction time, and a 7% cost of capital. Cement may be delivered to other zones at the freight cost of Section 3.9.

Clinker. Clinker is produced by existing clinker capacity and by five new technologies, and it is consumed in the zone that produces it. Kiln heat is supplied to the clinker kiln heat blend by kiln burners, which convert fuel to kiln heat at 80% efficiency; existing burners use coal, natural gas, petroleum coke, and municipal solid waste, and new burners use biomass, hydrogen, and natural gas. The inputs per tonne of clinker of the new technologies are:

Technology	Kiln heat or fuel	Electricity	Process CO_2	CO_2 captured	First year
Conventional	2.93 GJ kiln heat and 0.047 MMBtu pipeline gas	95 kWh	0.507 t	None	2026
Oxyfuel, gas-fired, with capture	3.66 GJ pipeline gas	264 kWh	0.507 t	0.622 t	2030

Technology	Kiln heat or fuel	Electricity	Process CO_2	CO_2 captured	First year
Oxyfuel, biomass-fired, with capture	3.66 GJ dry high-ash biomass	285 kWh	0.507 t	0.749 t	2030
Direct separation with capture	1.06 GJ kiln heat	949 kWh	0.507 t	0.446 t	2040
Direct separation retrofit of existing clinker capacity	2.96 to 3.02 MMBtu kiln heat	0.49 to 0.53 MMBtu	0.507 t	0.469 t	2040

Each capture technology sends its captured CO_2 either to sequestration or to utilization (two modes). The capital costs are 333 US dollars (2021) per t-year for conventional clinker, 422 for direct separation, and 517 for the oxyfuel kilns, and 177 euros (2019) per t-year for the retrofit. New clinker technologies have a minimum capacity factor of 0.70 and a maximum of 0.80, and new kiln burners a maximum of 0.95. The new clinker technologies and kiln burners may be built in every zone except Alaska and Hawaii, with no limit on capacity.

New industrial technologies. New conversion technologies take cost and efficiency from the sources cited in each row. They cover:

- Cement: portland cement grinding and limestone calcined clay cement, described above.
- Steel: blast furnace and basic oxygen furnace with and without capture, coke production with capture, natural gas direct reduction with and without capture, hydrogen direct reduction, electric arc furnace, and conventional and hydrogen-fired hot rolling, cold rolling, and continuous casting. Capital and fixed operating cost and energy use of the production routes come from the NEMS AEO 2026 steel inputs (2021 dollars, 40-year life), with iron ore and energy inputs of direct reduction from the Agora Industry steel calculator. The capture increments of blast furnace and coke production come from NETL (2023). Finishing capital costs come from published steel-industry cost benchmarks recorded in the source column.
- Clinker and lime: conventional, oxyfuel (gas- and biomass-fired), and direct-separation kilns with capture, direct-separation retrofits, and kiln burners on biomass, hydrogen, and natural gas. Conventional clinker and lime come from the NEMS AEO 2026 Cement and Lime inputs; the capture increments of the oxyfuel and direct-separation kilns come from the Agora Industry *Cement Transformation Cost Calculator* (2022), and the retrofits from LEILAC-2 Deliverable D2.4 (2023). Limestone feed is priced from the USGS *Mineral Commodity Summaries 2024* (crushed stone). Kiln burner cost and efficiency are set by assumption.
- Hydrogen: alkaline and PEM electrolysis, steam methane reforming, autothermal reforming with capture, and liquefaction. Electrolysis capital cost comes from the DOE *Pathways to Commercial Liftoff: Clean Hydrogen* (December 2024 update, Table A1), fixed operating cost is 3% of capital, and efficiency is the NEMS AEO 2026 value of 55.5 kWh per kg. Reforming comes from NREL H2A-Lite.
- Synthetic and bio-based fuels: Fischer–Tropsch liquids, methanation, alcohol-to-x, hydroprocessed esters and fatty acids including refinery conversion, biomass gasification to gas and to liquids with capture, fast pyrolysis with capture, cellulosic ethanol, corn ethanol with capture, anaerobic digestion, biogas upgrading, and ethanol blending.
- Ammonia (Haber–Bosch) and data centers.
- Process heat: pipeline gas, hydrogen, and electric boilers, heat pumps, geothermal heat, and thermal storage.

The capital costs of the steel production routes, the clinker and lime kilns, and coke production with capture are installed costs, taken as 1.5 times the engineering-study cost. Other principal sources are the IEA *Future of Hydrogen* assumptions annex, IEA Bioenergy, the European Commission technology pathways study, Pieper et al. (2018) for heat pumps, the IRENA thermal energy storage outlook, and the peer-reviewed studies cited in the source column.

Industrial demand response. Industrial load shedding is offered as five new technologies (tiers) ordered by cost, estimated bottom-up by manufacturing subsector from the EIA *Manufacturing Energy Consumption Survey 2018* and the Census *Annual Survey of Manufactures 2018*, with recoverability from Federal Reserve G.17 capacity utilization. The cost of each tier is entered as an all-in capital cost in 2018 dollars per kW with a one-year life and an 8% cost of capital: about 30, 53, 75, 112, and 229 $/kW (zonal medians) for tiers 1 to 5. Each tier may be called for up to 100 hours per year (maximum capacity factor 0.0114), is dispatched in four-hour blocks, and may be built from 2027. Potentials by state are in CUMULATIVE_BUILD_CAP; across the five tiers they total about 7.7 GW in 2026 and 72.6 GW in 2050. Availability follows the industrial machine-drive load shape.

3.11 Demand-side inputs supplied by EP

The tables in Demand/Demand Techs and Demand/Exogenous EP Inputs, together with the demand profiles in Shapes, are written by EP runs. The runs take most of them from a high-electrification EP case and a few (minimum sales, feeder allocation, and shipping demand) from a reference-demand EP case. Their content and derivation are documented in the *EnergyPATHWAYS US Database* document. In summary:

Tables	Content
DEMAND_TECH_*	For subsectors whose technology mix RIO optimizes: baseline sales, minimum and maximum sales, service demand per unit, service demand modifiers by age, efficiency, capital cost, and fixed cost by technology, vintage, and zone
EXO_DEMAND	Final energy demand by subsector, carrier, and zone for subsectors with a fixed technology mix; also fixed pipeline gas exports, shipping fuel, and cement, lime, and steel demand
DEMAND_EE_*, DEMAND_FS_*	Efficiency and fuel-switching measure savings, additions, and costs
DEMAND_DISPATCH_FEEDER_ALLOCATION	Allocation of demand to distribution feeder types

Cement demand is the EP clinker demand divided by 0.8716 t of domestic clinker per t of cement: 90.7, 87.1, 91.5, 97.7, 99.0, and 103.0 Mt in 2026, 2030, 2035, 2040, 2045, and 2050.

Two groups of demand tables are maintained in the RIO database itself:

- DEMAND_SUBSECTOR_MAIN and DEMAND_TECH_MAIN define the subsectors and demand technologies, their units, shapes, and whether the subsector's technology mix is optimized. The runs optimize the technology mix of 17 of the 85 subsectors, with 123 demand technologies (Section 2.8).
- DEMAND_PAYBACK_CURVES gives the payback-acceptance distribution by demand group, which RIO uses to allocate demand technology adoption (Section 8.6 of the *RIO Model* document). The curves and their sources are given in Section 2.11.

3.12 Policy tables

Policy constraint tables hold the data that RIO turns into constraints or prices. The run configuration determines which constraints enter a run (Section 2.7), and the values in each case are given in Section 2.1. The runs use the following tables:

Table	Structure
EMISSIONS_PRICE	Price per tonne by gas and year
BLEND_GROUP_EMISSIONS_INTENSITY_CAP	Carbon-intensity ceiling for a group of carriers or products
BLEND_DEEMED_EMISSIONS	Deemed emission intensity of each blend used in intensity standards
EMISSIONS_CONSTRAINT	Annual emissions cap by zone group and year. The rows the runs use carry no finite cap; the national CO_2 cap of the alternative cap case is entered directly in that case's model inputs (Section 2.1)
CAPACITY_RESERVES_CONSTRAINT	Planning reserve margin by zone: 15% in most zones, 13.75% in the Texas zones, 17% in the California zones, 17.7% in the PJM zones, 18.1% in the MISO zones, and zero in the export zone

3.13 Emissions factors

Gases. Emissions are accounted as CO_2 (Section 2.9).

Combustion factors. Commodity CO_2 contents per MMBtu are 95.52 kg for thermal coal, 93.9 for coking coal, 74.60 for imported unfinished oil and blending components, and 70.22 for imported refined products. The oil and gas supply commodities carry the district-weighted contents of Section 3.5.1. Biomass commodities carry zero combustion CO_2, except the fossil-derived fractions of municipal waste (74.6 kg/MMBtu for plastics, 37.3 for textiles and for rubber and leather) and some fats and greases, which carry a CO_2 rate per pound. Of these municipal waste fractions, only textiles are admitted to the municipal solid waste blend (Section 3.5.3). Sequestration commodities (geologic and EOR CO_2 sequestration) carry −1 tonne per tonne.

Process and conversion emissions. TECH_CONVERSION_EMISSIONS holds process CO_2 released or captured by conversion technologies per unit of output blend, including the output-blend carbon contents of the oil and gas extraction technologies (Section 2.10). Carbon capture appears as a negative coefficient on a CO_2 blend in the technology's efficiency table.

4 Table reference

Each table below also carries the common columns of Section 1.6 where relevant. Key columns lists the table-specific index and value columns.

4.1 Demand

Table	Description	Key columns
DEMAND_SUBSECTOR_MAIN	Demand subsectors: sector, service demand unit, default shape, and whether the technology mix is optimized	name, sector, service_demand_unit, optimize, isolated, shape

Table	Description	Key columns
DEMAND_PAYBACK_CURVES	Payback-acceptance distribution by demand group	name, payback_years, value
DEMAND_DISPATCH_FEEDER_ALLOCATION	Allocation of zone demand to distribution feeder types (EP)	name, dispatch_feeder, year, value

4.2 Demand technologies

All tables in this group are written by EP.

Table	Description	Key columns
DEMAND_TECH_MAIN	Demand technologies: subsector, lifetime, unit, linked technology, shape	name, subsector, lifetime, linked_tech, link_ratio, unit, shape, timestep
DEMAND_TECH_SALES_EP	Baseline sales by technology, vintage, and zone	name, subsector, vintage, value
DEMAND_TECH_SALES_MIN, DEMAND_TECH_SALES_MAX	Bounds on sales	name, subsector, vintage, value
DEMAND_TECH_SERVICE_DEMAND	Service demand met per unit of stock	name, subsector, unit, year, value
DEMAND_TECH_SERVICE_DEMAND_MODIFIER	Service demand modifier by vintage and year	name, subsector, vintage, year, value
DEMAND_TECH_EFFICIENCY	Efficiency by input carrier	name, blend_in, numerator_unit, denominator_unit, vintage, value
DEMAND_TECH_CAPITAL_COST	Capital cost per unit	name, subsector, vintage, value
DEMAND_TECH_FIXED_OM	Fixed cost per unit per year	name, vintage, year, value

4.3 Exogenous EP inputs

Table	Description	Key columns
EXO_DEMAND	Final demand by subsector, carrier, and zone for non-optimized subsectors; fixed exports; shipping fuel	name, sector, blend, unit, year, value
DEMAND_EE_SAVINGS, DEMAND_EE_COSTS	Efficiency measure savings by carrier, and cost	measure, subsector, blend, year or vintage, value
DEMAND_FS_SAVINGS, DEMAND_FS_ADDITIONS	Fuel-switching measure savings and additions	measure, subsector, blend, year or vintage, value

4.4 Gases

Table	Description	Key columns
GAS_GWP	Weight of each gas in emissions accounting	name, year, value

4.5 Geography and currency

Table	Description	Key columns
GEOGRAPHIES	Geographies and their units	geography, gau
GEOGRAPHIES_SPATIAL_JOIN	One row per county: membership in each geography and allocation quantities	one column per geography and per allocation key
GEOGRAPHY_MAP_KEYS	Valid allocation keys	name
INFLATION_CONVERSION	US price index by year	currency, year, value
CURRENCY_CONVERSION	Exchange rates by currency and year	currency, year, value

4.6 Policy constraints

Table	Description	Key columns
EMISSIONS_PRICE	Emissions price by gas	gas, unit, year, value
BLEND_GROUP_EMISSIONS_INTENSITY_CAP	Carbon-intensity ceiling on a group of carriers or products	blend_group, mass_unit, unit, unit_type, year, value
EMISSIONS_CONSTRAINT	Annual emissions cap by zone group	type, unit, year, value
CAPACITY_RESERVES_CONSTRAINT	Planning reserve margin by zone	year, value

4.7 Shapes

Table	Description	Key columns
SHAPE_META	Profile definitions: type, input type, geography, time zone	name, shape_type, input_type, time_zone, is_active
ShapeData/*	Profile data, one file or .csvd folder per profile; hourly profiles are indexed by weather_datetime, time-slice profiles by month or hour	gau, weather_datetime or month, value
TEMPERATURE_META	Temperature profile definitions	shape, unit, year, multiplier
CES_BINNING_WEIGHT	Weights of renewable profiles in representative-day selection	name, shape, binning_group, year, value
REGION_BINNING_WEIGHT	Weights of regions in representative-day selection	year, value

4.8 Blends

Table	Description	Key columns
BLEND_MAIN	Energy carriers and material products: unit type, timestep, whether physical transport constraints apply, emissions cap group membership	name, unit_type, timestep, enforce_physical_constraints, exceed_demand, include_in_conversion_emissions, emissions_*_group_in, emissions_*_group_out, is_active

Table	Description	Key columns
BLEND_CONNECTIONS	Minimum or maximum share of a blend supplied by a connected commodity or technology	name, connection, max_min, year, value
BLEND_DELIVERY_COST	Delivery margin by sector	name, sector, unit, year, value
BLEND_DELIVERY_COST_SHARES	Shares of delivery cost on flow, base, and peak	name, sector, cost_share, value
BLEND_LOSSES	Delivery losses by sector	name, sector, year, value
BLEND_DEEMED_EMISSIONS	Deemed emission intensity for intensity standards	name, mass_unit, unit, year, value

4.9 Commodities

Table	Description	Key columns
COMMODITY_MAIN	Commodities: type (inflow or accounting outflow), timestep, active flag	name, type, timestep, is_active, convex
COMMODITY_COST	Cost by bin and year	name, bin, unit, year, value
COMMODITY_POTENTIAL	Potential by bin, year, and type (annual, cumulative, pace_plateau, drill_decline_plateau, drill_decline_slope)	name, type, bin, unit, year, value
COMMODITY_TRAJECTORY	Fraction of one year's production persisting to the next	name, bin, year, value
COMMODITY_COST_PACE	Drilling-pace premium by play, bin, segment, and year	name, bin, segment, year, value
COMMODITY_GROUP_EXTRACTION	Drilling capacity of rig and footage groups	group_name, year, value
COMMODITY_GROUP_EXTRACTION_MEMBERS	Drilling capacity consumed per unit of each commodity bin	group_name, commodity, bin, unit, value
COMMODITY_EMISSIONS	Emission rates by commodity, bin, and gas	name, bin, gas, mass_unit, unit, year, value
COMMODITY_DELIVERY_COST	Delivery cost between geographies	name, geography_from, gau_from, geography_to, gau_to, year, value
COMMODITY_ELIGIBILITY	Permitted origin-destination pairs	name, gau_from, gau_to, year, value

4.10 Supply technologies: definitions and build constraints

Table	Description	Key columns
NEW_TECH_MAIN	New-build technologies: type, sector, constraint groups, shape, timestep	name, type, sector, *_build_cap_*_group, build_growth_penalty_*_group, shape, timestep, is_active

Table	Description	Key columns
EXISTING_TECH_MAIN	Existing plants: technology, location, capacity, storage, output limits	name, plant, type, capacity, capacity_unit, storage, generation_p_min, generation_p_max, include
EXISTING_TECH_SCHEDULE	Operating, minimum retirement, and retirement years	name, plant, operating_year, min_retirement_year, retirement_year
NEW_TECH_AVAILABILITY	Years and zones in which a technology may be built	name, year, value
CUMULATIVE_BUILD_CAP	Minimum and maximum cumulative capacity by group	group, type, incremental_to_existing, unit, year, min, max
NEW_TECH_ANNUAL_BUILD_CAP	Minimum and maximum annual additions by group	group, type, unit, year, min, max, cagr
NEW_TECH_BUILD_GROWTH_PENALTY	Penalty on growth in annual additions	group, type, year, value
TECH_RATIO_CONSTRAINT	Ratio constraints between technologies	name, tech, a_or_b, year, value
TECH_RETROFIT_CONSTRAINT	Retrofit relationships between existing and retrofit technologies	name, tech, a_or_b, year, value
TECH_TIMESTEP_AGG	Temporal aggregation applied to a technology's operation	name, vintage, value

4.11 Supply technologies: cost and finance

Table	Description	Key columns
TECH_CAPITAL_COST	Capital cost of new technologies, with construction time, lifetime, and cost of capital	name, cost_type, unit, construction_time, lifetime, book_life, cost_of_capital, vintage, value
TECH_FIXED_OM	Fixed operating cost	name, cost_type, unit, vintage, value
TECH_VARIABLE_OM	Variable operating cost by vintage and age	name, unit, vintage, age, value
NEW_TECH_TX_COST	Interconnection cost	name, unit, lifetime, cost_of_capital, vintage, value
TECH_FINANCING_MULTIPLIER	Technology-specific cost of capital	name, vintage, value
TECH_COST_MULTIPLIER	Regional capital cost multipliers	name, vintage, value
TECH_CURTAILMENT_COST	Cost of curtailing output	name, unit, vintage, year, value

4.12 Supply technologies: performance and operation

Table	Description	Key columns
NEW_TECH_EFFICIENCY	Input per unit output for single-mode technologies	name, blend_in, unit_in, unit_out, vintage, min_output_efficiency, max_output_efficiency

Table	Description	Key columns
NEW_TECH_EFFICIENCY_MODAL	Inputs and outputs by operating mode	name, bin, blend, in_out, unit, max_bin_share, vintage, min_output_efficiency, max_output_efficiency
EXISTING_TECH_EFFICIENCY	Single-mode efficiency of existing plants	name, plant, blend_in, unit_in, unit_out, min_output_efficiency, max_output_efficiency
EXISTING_TECH_EFFICIENCY_MODAL	Modal efficiency of existing plants	name, plant, bin, blend, in_out, unit, max_bin_share
NEW_TECH_CAPACITY_FACTOR	Minimum and maximum capacity factor by vintage	name, type, vintage, value
EXISTING_TECH_CAPACITY_FACTOR	Minimum and maximum capacity factor by plant	name, plant, type, year, value
NEW_TECH_P_MIN	Minimum stable output as a fraction of capacity	name, vintage, value
NEW_TECH_DURATION	Minimum and maximum storage duration	name, type, time_unit, vintage, value
TECH_CHARGE_DISCHARGE_RATIO	Ratio of charging to discharging capacity	name, vintage, value
TECH_RAMP	Ramp rate per minute	name, time_unit, vintage, value
TECH_OUTAGE	Outage rates and durations by outage type	name, outage_type, vintage, temperature, outage_rate, mean_outage_duration
TECH_DEPENDABILITY	Capacity credit for planning reserves	name, type, reserve_type, vintage, year, value
TECH_NTG	Net-to-gross output ratio, for carbon-capture plants	name, vintage, value

4.13 Supply technologies: emissions and delivery

Table	Description	Key columns
TECH_CONVERSION_EMISSIONS	Process emissions of conversion technologies per unit of output blend	name, blend, gas, mass_unit, unit, vintage, year, value
TECH_CONVERSION_DELIVERY_COST	Cost of delivering conversion output between geographies	name, gau_from, gau_to, unit, vintage, year, value
TECH_CONVERSION_ELIGIBILITY	Permitted origin-destination pairs for conversion output	name, gau_from, gau_to, vintage, year, value

4.14 Transmission

Table	Description	Key columns
TRANSMISSION_MAIN	Corridors: origin and destination zones, carrier, timestep, reporting group	name, gau_from, gau_to, blend, timestep

Table	Description	Key columns
TRANSMISSION_SCHEDULE	Existing capacity by direction and year	name, unit, time_unit, year, flow_value, counterflow_value
TRANSMISSION_POTENTIAL	Cumulative expansion potential	name, type, unit, time_unit, year, value
TRANSMISSION_AVAILABILITY	Years in which expansion is permitted	name, year, value
TRANSMISSION_CAPITAL_COST	Capital cost of expansion	name, unit, construction_time, lifetime, cost_of_capital, vintage, value
TRANSMISSION_FIXED_OM	Fixed operating cost of expansion	name, unit, vintage, value
TRANSMISSION_HURDLE	Transport charge, piecewise in utilization	name, unit, year, utilization, flow_value, counterflow_value
TRANSMISSION_LOSSES	Losses as a fraction of flow	name, vintage, year, value

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Appendix A Data sources

The table lists, for each input table, the sources of its data and the number of keys drawn from each source, where a key is the entity the rows describe (usually name, or group for build constraints). Only keys that are present in the runs are counted. Data without an external source are marked “By assumption”.

Table	Keys	Source
BLEND_CONNECTIONS	2	By assumption
BLEND_DEEMED_EMISSIONS	54	Per-blend emission intensities of the reference case, with accounting conventions by assumption (reference, carbon price, and emissions intensity cap cases)
	23	By assumption (alternative cap case)
COMMODITY_COST	10	EIA AEO 2026; NEMS Hydrocarbon Supply Module
	1	EIA AEO 2026
	1	FE/NETL CO_2 Saline Storage Cost Model; Princeton Net-Zero America
COMMODITY_EMISSIONS	10	EIA AEO 2026; NEMS Hydrocarbon Supply Module
	1	FE/NETL CO_2 Saline Storage Cost Model; Princeton Net-Zero America
COMMODITY_GROUP_EXTRACTION	1	EIA AEO 2026; NEMS Hydrocarbon Supply Module
COMMODITY_POTENTIAL	53	DOE 2023 Billion-Ton Report
	13	EIA AEO 2026; NEMS Hydrocarbon Supply Module

Table	Keys	Source
	6	LLNL Roads to Removal
	3	By assumption
	1	FE/NETL CO_2 Saline Storage Cost Model; Princeton Net-Zero America
	1	Princeton Net-Zero America
COMMODITY_TRAJECTORY	6	EIA AEO 2026; NEMS Hydrocarbon Supply Module
CUMULATIVE_BUILD_CAP	13	By assumption
	12	NREL ATB 2024
	5	NREL Geothermal Supply Curves 2024; NREL ATB 2024
	3	Cole et al. (2020)
	2	NREL ReEDS 2.0
DEMAND_DISPATCH_FEEDER_ALLOCATION	80	EnergyPATHWAYS US Database
DEMAND_EE_COSTS	11	EnergyPATHWAYS US Database
DEMAND_EE_SAVINGS	13	EnergyPATHWAYS US Database
DEMAND_FS_ADDITIONS	28	EnergyPATHWAYS US Database
DEMAND_FS_SAVINGS	28	EnergyPATHWAYS US Database
DEMAND_TECH_CAPITAL_COST	115	EnergyPATHWAYS US Database
DEMAND_TECH_EFFICIENCY	123	EnergyPATHWAYS US Database
DEMAND_TECH_FIXED_OM	112	EnergyPATHWAYS US Database
DEMAND_TECH_SALES_EP	123	EnergyPATHWAYS US Database
DEMAND_TECH_SALES_MAX	123	EnergyPATHWAYS US Database
DEMAND_TECH_SALES_MIN	123	EnergyPATHWAYS US Database
DEMAND_TECH_SERVICE_DEMAND	123	EnergyPATHWAYS US Database
DEMAND_TECH_SERVICE_DEMAND_MODIFIER	120	EnergyPATHWAYS US Database
EXO_DEMAND	79	EnergyPATHWAYS US Database
GAS_GWP	5	By assumption
NEW_TECH_ANNUAL_BUILD_CAP	3	By assumption
	1	EIA and Alternative Fuels Data Center biofuel plant capacity
NEW_TECH_AVAILABILITY	43	By assumption
NEW_TECH_BUILD_GROWTH_PENALTY	24	By assumption
NEW_TECH_CAPACITY_FACTOR	16	By assumption
	12	NREL ATB 2024

Table	Keys	Source
	3	NREL ATB 2021
NEW_TECH_EFFICIENCY	4	NREL ATB 2024
	1	EIA AEO 2026 (NEMS Hydrogen Market Module)
NEW_TECH_EFFICIENCY_MODAL	15	EIA AEO 2026; NEMS Hydrocarbon Supply Module
	2	NREL ATB 2024
NEW_TECH_TX_COST	12	NREL ATB 2024
	5	NREL Geothermal Supply Curves 2024; NREL ATB 2024
Shape data (ShapeData)	25	EnergyPATHWAYS US Database
	1	PNNL RectifHyd v1
	1	NREL Geothermal Supply Curves 2024
TECH_CAPITAL_COST	23	NREL ATB 2024
	15	EIA AEO 2026; NEMS Hydrocarbon Supply Module
	5	NREL Geothermal Supply Curves 2024; NREL ATB 2024
	3	IEA Future of Hydrogen (2019); IEA Bioenergy (2020)
	2	By assumption
	1	DOE Pathways to Commercial Liftoff: Clean Hydrogen (2024)
	1	Al-Wahaibi et al. (2020)
	1	NREL H2A-Lite
TECH_CONVERSION_ELIGIBILITY	1	EIA AEO 2026; NEMS Hydrocarbon Supply Module
TECH_CONVERSION_EMISSIONS	15	By assumption
TECH_FIXED_OM	23	NREL ATB 2024
	15	EIA AEO 2026; NEMS Hydrocarbon Supply Module
	5	NREL Geothermal Supply Curves 2024; NREL ATB 2024
	3	IEA Future of Hydrogen (2019); IEA Bioenergy (2020)
	2	EIA capital cost estimates (2020)
	2	By assumption
	1	DOE Pathways to Commercial Liftoff: Clean Hydrogen (2024)

Table	Keys	Source
	1	Mongird et al. (2019)
	1	NREL H2A-Lite
TECH_NTG	2	NREL ATB 2024
TECH_OUTAGE	40	NERC Generating Availability Data System
	3	By assumption
TECH_RATIO_CONSTRAINT	1	By assumption
TECH_VARIABLE_OM	6	NREL ATB 2024
	2	NREL H2A-Lite
	1	IEA Bioenergy (2020)

EMISSIONS_PRICE, BLEND_GROUP_EMISSIONS_INTENSITY_CAP, BLEND_DEEMED_EMISSIONS, and the primary emissions cap differ by case (Section 2.1). The emissions price is zero in the reference, emissions intensity cap, and alternative cap cases and rises to 200 US dollars (2024) per tonne of CO_2 in 2050 in the carbon price case. The intensity ceilings, which are set to the intensities the carbon price case reaches, apply in the emissions intensity cap case only, and the deemed intensities they use are those of the reference case; BLEND_DEEMED_EMISSIONS has no effect in the other cases. The national CO_2 cap, set to the emissions of the emissions intensity cap case from 2035, applies in the alternative cap case only.

The runs also read the following tables, whose sources are given in Sections 3 and 4: BLEND_DELIVERY_COST, BLEND_DELIVERY_COST_SHARES, BLEND_LOSSES, CAPACITY_RESERVES_CONSTRAINT, CES_BINNING_WEIGHT, COMMODITY_COST_PACE, COMMODITY_DELIVERY_COST, COMMODITY_ELIGIBILITY, COMMODITY_GROUP_EXTRACTION_MEMBERS, DEMAND_PAYBACK_CURVES, EMISSIONS_CONSTRAINT, EXISTING_TECH_CAPACITY_FACTOR, EXISTING_TECH_EFFICIENCY, EXISTING_TECH_EFFICIENCY_MODAL, EXISTING_TECH_MAIN, EXISTING_TECH_SCHEDULE, NEW_TECH_DURATION, NEW_TECH_P_MIN, REGION_BINNING_WEIGHT, TECH_CHARGE_DISCHARGE_RATIO, TECH_CONVERSION_DELIVERY_COST, TECH_COST_MULTIPLIER, TECH_CURTAILMENT_COST, TECH_DEPENDABILITY, TECH_FINANCING_MULTIPLIER, TECH_RAMP, TECH_RETROFIT_CONSTRAINT, TECH_TIMESTEP_AGG, TEMPERATURE_META, TRANSMISSION_AVAILABILITY, TRANSMISSION_CAPITAL_COST, TRANSMISSION_FIXED_OM, TRANSMISSION_HURDLE, TRANSMISSION_LOSSES, TRANSMISSION_POTENTIAL, TRANSMISSION_SCHEDULE.