Rhodium Group

Energy & Climate

Taking Stock 2026: Technical Appendix

July 29, 2026
Hannah Kolus (hkolus@rhg.com), Ben King (bking@rhg.com), Parker Case (pcase@rhg.com), Michael Gaffney (mgaffney@rhg.com), Nathan Pastorek (npastorek@rhg.com), Anna van Brummen (avanbrummen@rhg.com), Nathan Wiens (nwiens@rhg.com)

This document provides additional detail on the methods and data sources used in Rhodium Group's Taking Stock 2026 report. Direct access to all energy and emissions results from our Taking Stock 2026 baselines—including results broken down by gas and sector for all 50 US states through 2040—is available via ClimateDeck. In the past, we've sourced all historical greenhouse gas (GHG) emissions and removal estimates directly from the Environmental Protection Agency (EPA) Greenhouse Gas Inventory, but 2026 marks the second year in a row the EPA has not released this data inventory. In response to this anticipated data gap, the University of Maryland's Center for Global Sustainability (CGS) developed an inventory consistent with the methodology of the prior EPA inventory. We use this new data product for historical emissions from 2005 to 2024. Like the EPA inventory, all gases are reported in carbon dioxide (CO_2)-equivalent emissions based on the Intergovernmental Panel on Climate Change (IPCC) 5th Assessment Report (AR5) 100-year global warming potential (GWP) values. To model potential future emissions and policy scenarios, we use RHG-NEMS, a modified version of the detailed National Energy Modeling System used by the Energy Information Administration (EIA) to produce the Annual Energy Outlook 2026 (AEO2026) and maintained by Rhodium Group. We expand on this model to project all six GHGs targeted for reduction under the Kyoto Protocol.

Energy market, technology, and economic assumptions

To construct our national Taking Stock GHG emissions projections range, we revised multiple energy market, technology cost, policy, and behavioral assumptions in RHG-NEMS to be consistent with the most recent research and to reflect the range of market and economic uncertainties. We update these assumptions each year to reflect the best available data and information. More granular data for many of these inputs are included on ClimateDeck.

Unless otherwise stated below, we use EIA's AEO2026 Reference case assumptions in our Taking Stock projections.

RHG-NEMS inputs that are consistent across the emissions outlook

We make several revisions to input assumptions beyond EIA's AEO2026 Reference case that are consistent across our Taking Stock emissions range. The key revisions are described below.

ANNOUNCED POWER PLANT RETIREMENTS AND ADDITIONS

We incorporate all announced coal and nuclear power plant retirements through 2040. We also include plant openings that have at least begun the regulatory approval process from the EIA's March 2026 preliminary electric generator inventory (EIA Form 860M).

NUCLEAR POWER PLANT UPRATES AND RESTARTS

We include the non-proprietary nuclear uprates expected and reported by the Nuclear Regulatory Commission. This amounts to about 1 gigawatt of additional nuclear capacity. For modeling simplicity, we apply these uprates starting in 2025, even though uprates are expected to go into effect as late as 2034. The impact of applying these uprates early within our modeling is somewhat muted by the high levels of other planned additions (solar, storage, onshore wind, and natural gas) that come online through 2030, especially since most nuclear uprates are expected to go into effect by 2031.

AEO2026 included nuclear plant restarts Palisades (2026) and Crane Clean Energy (2028). We include both restarts and add one more: Duane Arnold (2029).

DATA CENTER DEMAND

RHG-NEMS generates projections for demand for electricity from several end-uses endogenously, including electric vehicles and building electrification, which then flow through to the model's power sector decisions. Recent analyses predict large demand growth driven by AI activity over the next decade. Taking Stock 2026 includes increased electricity demand from data centers in all three baseline emissions scenarios. We have consistently revised data center demand growth assumptions upwards for each Taking Stock iteration since 2024, the first year we included data center demand. Based on our most up-to-date review of external analyst projections for where demand could be heading, we developed a growth pathway in which data center demand increases by 71% above 2025 levels in 2030 and by 233% in 2040.

NATURAL GAS TURBINE CONSTRAINTS

Anticipated significant growth in data center demand has prompted developers to rush to build extra capacity into their resource planning. Additionally, the rise of hyperscale facilities that have large energy requirements means that developers must deploy considerable amounts of generating capacity at once to service data centers. For instance, Microsoft recently announced a 2-gigawatt data center in Texas powered primarily by GE Vernova natural gas turbines. Three companies dominate US gas turbine manufacturing capacity: GE Vernova, Siemens Energy, and Mitsubishi Power. The frenzy of activity around gas capacity development for data centers has driven a years-long backlog for gas turbines in the US as demand outpaces supply.

To reflect these supply constraints in RHG-NEMS, we explicitly include all planned gas turbine capacity as reported in EIA's March 2026 preliminary electric generator inventory, and we only allow unplanned gas turbine additions starting in 2030. As a result of the turbine supply crunch, reports show that capital costs for natural gas power plants doubled over the last year or so. We represent this price increase in RHG-NEMS through 2030. We assume that gas turbine manufacturing capacity expands sufficiently by that time to alleviate prices to pre-supply crunch levels. GE Vernova is already taking steps to expand its production capacity and has plans for larger expansions in the coming years.

METHODOLOGIES NEW TO TAKING STOCK 2026

We added two methodological updates to better represent observed dynamics in today's power sector.

- **Permitting constraints:** As electricity demand ticks up, the non-cost barriers to deploying new capacity become even more urgent. The interconnection queue has been growing over the last several years, and building out grid infrastructure like transmission remains challenging, expensive, and slow going. Slow transmission expansion in particular impacts variable renewable additions more than other technologies, since these plants must be located where quality solar and wind resources exist, which isn't always near demand centers or accessible grid infrastructure. We represent these barriers by increasing grid connection costs for solar and wind.

- **Electricity price adjustments:** To capture the impact of recent inflationary trends in transmission and distribution (T&D) equipment and wildfire- and storm-related costs on electricity prices, we calibrated T&D components of electricity prices based on two sources of data: we scaled T&D prices in California to match a 2025 California Public Utility Commission Report, and we scaled T&D prices in other regions to match regional electricity prices in EIA's June 2026 Short Term Energy Outlook (STEO).

Sources of uncertainty

To construct the full range of emission projections in Taking Stock, we considered three key sources of uncertainty:

- **Economic growth:** We use two different projections of US gross domestic product (GDP) growth in TS2026: a baseline growth rate and a high growth rate.

- **Energy markets:** We consider a range of energy market variables that shape emissions outcomes, including natural gas and oil resource availability and prices. We include two different pathways for planned liquid natural gas (LNG) export capacity.

- **Technology cost and performance:** We estimate ranges for key technology cost and performance variables, including capital and operating costs for clean electricity generators, battery costs for light-duty electric vehicles, and capital costs for industrial point-source carbon capture retrofits.

For each of these sources of uncertainty, we defined a mid, low, and high case to reflect a range of potential market and technology cost outcomes (Table 1). To create our low-emissions scenario, we combine high oil and gas prices with the lowest projections of clean technology capital costs, baseline economic growth, and planned LNG export capacity reflecting under-construction facilities. Our high-emissions scenario is the reverse, combining low oil and gas prices with high-cost clean technologies, high economic growth, and a broader range of planned LNG export facilities. The mid-emissions scenario generally adopts more moderate trajectories for these factors. In the following sections, we describe the key assumptions that vary across our estimated emissions range and underlying data sources.

TABLE 1

Select executive orders relating to climate or energy issued during the Trump administration

TS2025 Scenarios	Low emissions	Mid emissions	High emissions
Economic growth	Baseline	Baseline	High
Oil and natural gas prices	High	Mid	Low
Planned LNG export capacity	Under construction	Under construction	Under construction or permitted
Clean technology costs	Low	Mid	High

RHG-NEMS inputs that vary to capture macroeconomic uncertainty

We reviewed a range of macroeconomic projections from government institutions, non-governmental organizations, and the financial sector including economic growth, inflation, and federal funds rates. Based on these forecasts, we selected two forecasts to bound economic expectations in our emissions scenarios.

Under baseline economic conditions, used in our mid and low-emissions scenarios, GDP growth averages 1.8% annually through 2040. This level of growth is aligned with the latest CBO projections. Under higher economic growth assumptions, used in our high-emissions scenario, GDP growth averages 2.3% annually through 2040. This growth rate assumes that the US economy continues to grow at levels consistent with average annual GDP growth from 2010 to today (2.4%).

Economic conditions alone play an important role in future emissions pathways. Household disposable income influences factors like vehicle purchasing decisions, vehicle miles traveled, and home energy consumption. Industrial output, a key component of GDP, is also positively correlated with emissions. In our testing, we found that a shift from baseline to high economic growth while holding all other inputs constant yields an emissions increase of about 100 million metric tons per year by 2035. On the other hand, any surprise shocks that push GDP down can also decrease emissions, though such shocks are not captured in this framework.

IMPACTS OF TARIFFS

The Trump administration's tariffs have stabilized somewhat and at lower levels compared to this time last year (though that might be changing). Research groups have also had a year to integrate them into analysis. This year, "reciprocal" tariffs are broadly embedded in the macroeconomic assumptions associated with AEO2026, and we make no additional changes. Solar-specific tariffs (Section 201, anti-dumping and countervailing duty) are also included in the estimates of current solar capital costs that underlie our projections.

RHG-NEMS inputs that vary to capture energy market uncertainty

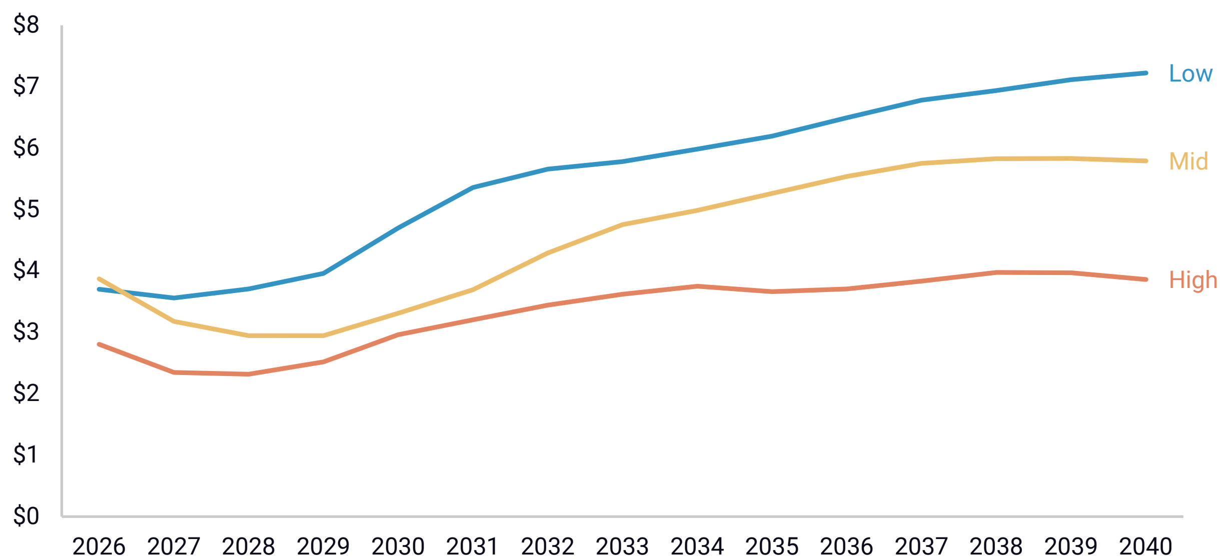
IRAN WAR IMPACT

Across all scenarios, we reflect the impacts of the ongoing Iran war by increasing the price of oil and refined petroleum products (e.g., motor gasoline, diesel, jet fuel). We calibrate prices to align with EIA's June STEO, which assumes that the conflict ends mid-year and that oil prices return to pre-conflict levels in 2027. As a result, all emissions scenarios see Brent crude prices exceed $90/b in 2026 and fall back down to around $55/b in 2027. The prices of refined petroleum products remain elevated for a few more years before returning to pre-conflict levels.

This single-year spike in oil prices impacts fossil fuel production levels and natural gas prices. High oil prices drive increases in oil and gas production that peak around 5-10% (3-4 quads) in the near-term and fall to zero by 2040, compared to a scenario without the 2026 oil price spike. Elevated oil and gas production drives natural gas prices down by about 20% in the near-term compared to a scenario without the oil price spike.

OIL AND GAS PRICES

FIGURE 1
Natural gas spot price at Henry Hub
2025 dollars per million Btu



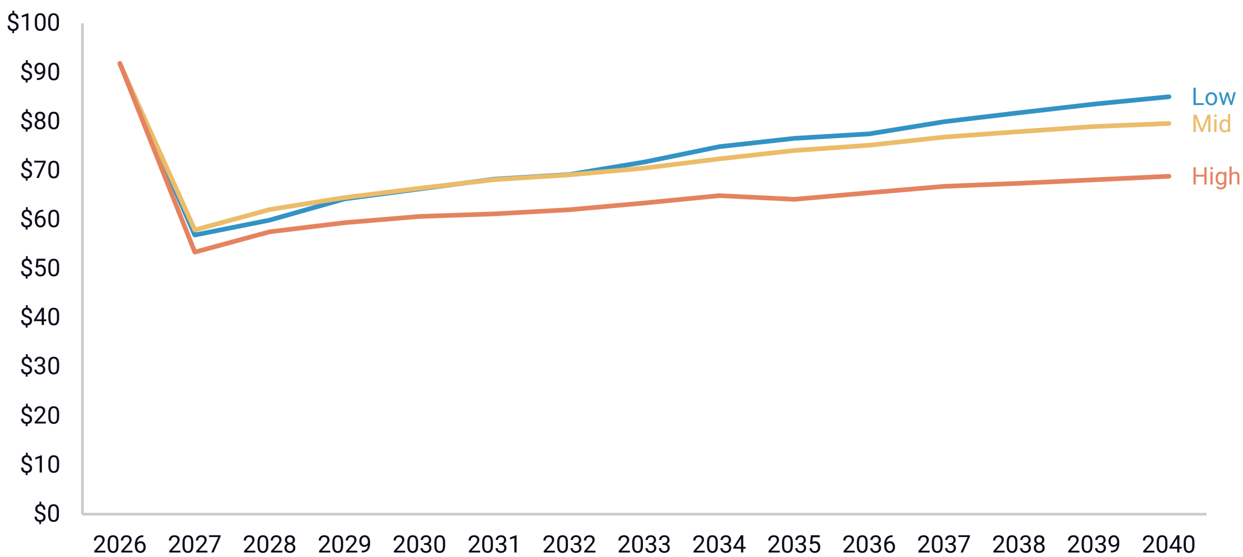
Source: Rhodium Group analysis, EIA

We use three sets of energy market conditions to build our emissions scenarios. In the lowest price projection, which corresponds to our high-emissions scenario, natural gas prices at Henry Hub remain at or below the 2026 levels of $2.80/MMBtu through 2029 (Figure 1). Prices modestly decrease through 2028, continuing some of the lowest annual average prices in recent history. After 2029, prices increase steadily before leveling off at an average price of $3.90/MMBtu between 2036 and 2040. Brent crude prices remain relatively flat across the projection period, and short-term price shocks do not extend past the current year (Figure 2). Excluding 2026, prices average $65/barrel through 2040. These prices represent robust growth of US oil and gas production through 2040, meeting both increasing domestic consumption and increasing LNG exports.

The mid fossil price projection sees Henry Hub prices following a similar path to the low-price projection. Henry Hub prices fall through 2029, reaching $3.00/MMBtu. Prices start increasing in 2030 before evening out at an average of $5.80/MMBtu from 2037 to 2040. Brent prices increase from $58/barrel in 2027 to $80/barrel by 2040. These prices represent roughly flat domestic oil production paired with modestly increasing gas production through 2040.

In the high fossil price projection, gas prices increase each year from 2027 to 2040. Gas prices rise from their lowest value of $3.60/MMBtu in 2027/MMBtu, up to $4.70 by 2030 and $7.20/MMBtu by 2040. Brent prices average $62/barrel in the near-term, excluding 2026. The high-cost pathway sees the largest rise in Brent spot price over the model window, reaching $85/barrel by 2040 as both oil and gas production decline over time.

FIGURE 2
Brent crude oil spot price
2025 dollars per barrel



Source: Rhodium Group analysis, EIA

PLANNED LNG EXPORT CAPACITY

The US is already the world's leading LNG exporter, with considerable export capacity under development. RHG-NEMS includes planned LNG export capacity that is already in the pipeline and models additional LNG export capacity expansions based on international demand for gas at the price of production plus transportation. In all scenarios, we update planned LNG export capacity with EIA's latest data on facilities that are either under construction or in the commissioning stage. To reflect the bull case for LNG growth, particularly in a high macroeconomic growth environment, we add more planned LNG capacity in our high-emissions pathway to include 10.0 billion cubic feet of additional capacity. This includes projects that have secured all required export permits and offtake agreements for most of their capacity but have not yet made final investment decisions.

RHG-NEMS inputs that vary to capture clean technology cost and performance uncertainty

ELECTRIC GENERATING TECHNOLOGY COSTS

In past Taking Stock reports, we used the National Laboratory of the Rockies' (NLR) Annual Technology Baseline (ATB) for clean technology costs. Since NLR hasn't published an ATB report since 2024, we take a new approach this year that continues to utilize NLR research. For utility-scale solar and rooftop solar, we create technology cost pathways that start from updated estimates of current solar capital costs and apply cost reductions roughly in line with ATB 2024, albeit on a two-year delay. We take the same approach with land-based wind, but estimates of wind CAPEX increased meaningfully from the base study underlying ATB 2024. As a result, our onshore wind capital costs are 7% higher on average from 2025 to 2040 than the costs in Taking Stock 2025. For utility-scale storage, we derive our cost projections from a recent NLR study that published mid, low, and high battery cost pathways based on a literature review of recent estimates. We continue to use ATB 2024 for offshore wind capital costs.

We update geothermal site availability and capital costs to reflect recent studies and technology updates for this energy resource. We use hydrothermal capital costs and resource availability from DOE's 2019 Geovision report. We also include revamped Enhanced Geothermal System (EGS) representation with site-level potential capacity and capital costs sourced from Ricks et. al (2022) out of the Princeton Zero Lab.

For nuclear technologies, we base starting capital costs on a 2024 MIT study for advanced light water reactors and a 2024 report from the Energy Future Initiatives Foundation for small modular reactors. We allow RHG-NEMS to endogenously solve for cost evolution over the model window.

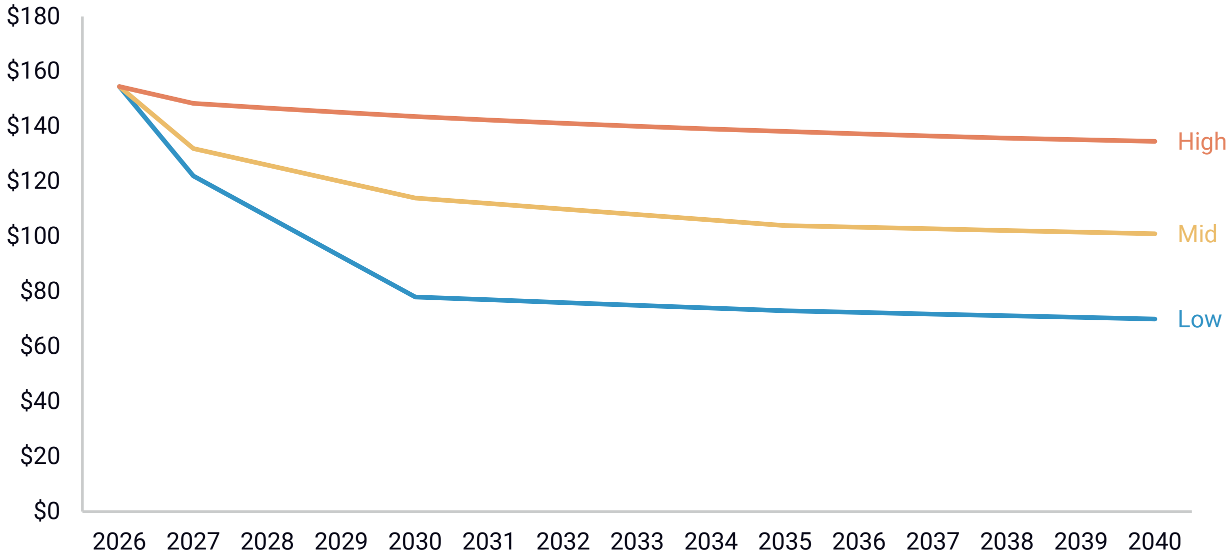
We base capital costs for natural gas combined cycled units with carbon capture on a 2023 National Energy Technology Laboratory report. For unabated fossil generator costs, we rely on AEO2026 counterfactual baseline capital cost assumptions with an additional short-term cost increase for natural gas turbines reflecting the AI-driven race to acquire new natural gas generators.

Granular utility-scale clean technology capital cost data are available on Rhodium Group's ClimateDeck.

ELECTRIC VEHICLE BATTERY COSTS

Our electric vehicle battery price pathways start from AEO2026 prices in 2026, then diverge. Our low and mid-battery cost pathways are aligned with the 2024 Transportation ATB Advanced and Mid battery cost assumptions, respectively. Our high battery cost pathway assumes that battery costs decline at half of the annual rate of AEO2026's counterfactual baseline battery costs.

FIGURE 3
Electric vehicle battery price
2025 dollars per kilowatt-hour



Source: Rhodium Group analysis, EIA, NLR

INDUSTRIAL CARBON CAPTURE COSTS

We continue to rely on our Industrial Carbon Abatement Platform (ICAP) to assess economic opportunities for industrial point-source carbon capture retrofits. Using ICAP, we project future carbon capture retrofits at existing industrial facilities under low, mid, and high-cost assumptions for CO_2 capture, transportation, and storage. ICAP is integrated with the rest of RHG-NEMS such that industrial facilities see dynamic energy costs and expected revenue from CO_2 sales. The AEO2026 edition of NEMS includes endogenous industrial carbon capture projections for a subset of subindustries available in RHG-ICAP. We remove the endogenous industrial carbon capture in RHG-NEMS and replace it with RHG-ICAP projections, though in future years we intend to integrate these assessments with EIA's new modules.

Federal and state policy assumptions

Our scenarios include emission reductions from all actionable and quantifiable existing federal and state policies as of June 2026. To remain consistent with United Nations (UN) guidelines for reporting the impact of "current measures," we generally include only policies that have been finalized and adopted, though we note several exceptions below. We do not include aspirational goals or economy-wide targets that have not been solidified in specific, actionable policy, nor do we explicitly include specific city-level or corporate commitments.

On the federal regulatory level, we include EPA's finalized repeal (February 2026) of GHG standards for model year 2027 and later light-duty, medium-duty, and heavy-duty vehicles. We also include EPA's update to hydrofluorocarbon standards, finalized this May, that delays implementation of the standards by several years. We assume that EPA finalizes the repeal of GHG standards for power plants and oil and gas operations. This month, EPA is expected to finalize the repeal of power plant regulations and propose a sweeping overhaul of O&G methane standards. While these actions aren't yet finalized and will likely face court challenges, the administration has prioritized deregulation, and the courts have generally allowed the administration's rollbacks to stand. As a result, we expect the finalized rules to hew very closely to a complete rollback and believe it is appropriate to discuss energy system and climate trends accordingly.

We continue to exclude California's Advanced Clean Cars 2 (ACC2) and Advanced Clean Trucks (ACT) following the action Congress took to revoke California's federal waivers that granted the state authority to set emissions standards for light-duty vehicles and trucks that were more stringent than national ones. California is challenging this decision in the courts, but will likely face a long uphill battle.

We describe our policy assumptions in greater detail in the sections below.

CO_2 policies

CARBON PRICING: We include the Washington Cap-and-Invest Program, the California Cap-and-Trade Program, and the Regional Greenhouse Gas Initiative (RGGI), which prices electricity sector carbon emissions from 11 states. We do not include Virginia as a RGGI member this year since Virginia's House Bill 29, which required the state to rejoin RGGI by May 31, 2026, also requires the state to redefine their budgets by January 1, 2026. We plan to include Virginia in RGGI in next year's Taking Stock. Carbon pricing policies that have not been finalized with clear, implementable milestones are not included in our analysis. This includes the New York Cap-and-Invest Program, which was announced by Governor Hochul in January 2023 and directs policymakers to design an economy-wide Cap-and-Invest Program that establishes a declining cap on greenhouse gas emissions. We do not explicitly include the Oregon Climate Protection Program.

ELECTRIC POWER: Taking Stock 2026 excludes EPA's standards regulating carbon pollution from existing coal-fired and new gas-fired power plants promulgated under the Clean Air Act sections 111(d) and 111(b). We also exclude EPA's final rule to strengthen and update the Mercury and Air Toxics Standards for Power Plants. We represent EPA's 2021 update to the Cross-State Air Pollution Rule that revised emissions budgets through 2024, but we exclude EPA's 2023 "Good Neighbor" plan because the Supreme Court issued a stay on implementation in June 2024. We include the Civil Nuclear Credit enacted as part of the Infrastructure Investment and Jobs Act (IIJA). All Inflation Reduction Act (IRA) tax credits reflect adjustments to the timeframe and eligibility requirements implemented via OBBBA last year. We include a list of state-level Renewable Portfolio Standards (RPS), Clean Energy Standards (CES), and zero-emission credit programs in Table 1. We continue to exclude state offshore wind mandates due to persistent timeline delays and now the suite of federal actions levied against offshore wind development.

TRANSPORTATION: In the transportation sector, we include harmonized EPA and National Highway Traffic Safety Administration's CAFE standards for LDVs through model year 2026. We no longer include EPA's multi-pollutant emissions standards for model years 2027 and later for LDVs and medium-duty vehicles (MDVs) or EPA's Phase 3 standards for heavy-duty vehicles (HDVs) in our baselines. All IRA tax credits for clean vehicles, clean fuel production, sustainable aviation fuel, and clean hydrogen production have been adjusted to reflect OBBBA updates. We also include the federal Renewable Fuels Standard requirements.

At the state level, we include vehicle emission standards and zero-emission vehicle (ZEV) mandates for California and 15 states that follow California's tighter standards (Advanced Clean Cars I) under Section 177 of the Clean Air Act (S177 states). We exclude ACC2 regulations previously adopted in CA and 12 other S177 states that required 100% light-duty ZEV sales by 2035. We also exclude ACT regulations (requiring 40%-75% zero-emission truck sales, depending on truck weight class, by 2035) in CA and the 10 additional states that previously adopted them. We include the California, Oregon, New Mexico, and Washington low-carbon fuel standards as well as California's Innovative Clean Transit regulation (requiring 100% zero-emission bus sales by 2040). State ZEV commitments with no underlying regulatory policy are not included in our modeling.

INDUSTRY AND BUILDINGS: We include current federal minimum energy conservation standards for appliances and equipment, as well as the IRA's tax credits and rebates for residential and commercial energy efficiency and clean energy expenditures in accordance with OBBBA implementation changes. We also include the tax credits for carbon dioxide sequestration (45Q), clean hydrogen production, and clean fuel production. State energy efficiency programs are implicitly captured in RHG-NEMS electric demand projections. We also capture the impacts of federal investment in clean hydrogen and direct air capture hubs that were funded as part of the IIJA.

Non-CO_2 policies

METHANE: We assume emission reductions from EPA's 2016 updated NSPS and emission guidelines for methane from municipal solid waste landfills rules are delayed—with enforcement starting in 2021 rather than 2016—to reflect EPA's update to the Obama-era rule. The following state policies are also reflected: oil and gas standards in 10 states and California's landfill methane control measures from 2010 and updated in 2017. All estimates associated with federal and state oil and gas rules are based on modeled estimates from the Clean Air Task Force that align with oil and gas production from each of our scenarios. For landfills, we used emission reduction estimates from EPA and California's Air Resources Board.

HYDROFLUOROCARBONS (HFCS): All our scenarios assume a phasedown in the production and consumption of HFCs in line with EPA's final rule to phase down HFCs, issued September 2021. However, we also reflect the EPA's delayed enforcement of the Technology Transitions rule, which gives certain sectors more time to switch to lower GWP refrigerants.

Federal and state policies included in Taking Stock 2026 baselines

FEDERAL POLICY

*Includes modifications defined in the Fiscal Year 2025 budget reconciliation bill (OBBBA)

Power sector
- Clean electricity tax credits*
- Tax credit direct pay provisions and transferability

- Zero-emitting nuclear production tax credit*
- USDA assistance for rural electric cooperatives
- Tax credit for carbon oxide sequestration (45Q)*
- CCS demonstration and pilot projects
- Civil Nuclear Credit Program
- Cross-State Air Pollution Rules (CSAPR)
- Mercury and Air Toxics Standards (MATS)
- New Source Review (NSR)

Transportation
- New clean vehicle tax credit*
- New clean commercial vehicle tax credit*
- EV charging infrastructure grants*
- Clean fuels tax credit*
- Clean hydrogen production tax credit (45V)*
- Sustainable aviation fuel credit*
- Renewable Fuel Standards (RFS)
- MY2024-2026 Corporate Average Fuel Economy Standards
- GHG and fuel consumption standards for heavy-duty vehicles, Phase 2
- Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards
- Tier 3 Motor Vehicle Emission and Fuel Standards Program
- International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI

Industry and buildings
- Clean hydrogen production tax credit (45V)*
- Clean fuel production tax credit*
- Building efficiency tax credits*
- Building electrification and efficiency grants*
- Federal investments in clean hydrogen and direct air capture hubs in IIJA

Hydrofluorocarbons (HFCs)
- EPA's final rule to phase down HFCs and subsequent modifications

Methane
- Orphaned mine and well remediation
- Updated onshore and offshore oil and gas royalty rates*
- EPA municipal solid waste landfill methane rule

Carbon removal
- Tax credit for carbon dioxide sequestration (45Q)*

STATE POLICY

Power sector
Relevant states

- Renewable portfolio standard (RPS) and clean electricity standard (CES)
  AZ CA CO CT DC DE IL MA MD ME MI MN MO NC NE NH NJ NM NV NY OH OR PA RI VA VT WA WI

- Nuclear zero-emission credit (ZEC) programs
  IL NJ NY

Transportation
Relevant states

- California LDV GHG standards or ZEV mandate (Advanced Clean Cars I regulation)
  CA CO CT ME MD MA MN NJ NM NV NY OR RI VA VT WA
- State electric, hybrid, and alternative-fuel vehicle tax and other incentives
  CA CO CT DE DC IL MA MD ME MN NJ NY OR PA RI VT WA
- Low-Carbon Fuel Standard (LCFS)
  CA OR NM WA
- Zero-emission bus mandate
  CA

Industry and buildings
Relevant states

- Energy Efficiency Resource Standards (EERS)
  AK AZ CA CO CT DC HI IA IL LA MA MD ME MI MN MO MS NC NH NV NJ NM NY OR PA RI TX UT VA VT WA WI

Methane
Relevant states

- State oil and gas standards
  CA CO MA MD NM NY OH PA UT WY
- Landfill methane regulation (LMR) and SB1383 agricultural methane targets
  CA

Carbon pricing
Relevant states

- Cap and trade program
  CA WA
- Regional Greenhouse Gas Initiative (RGGI)
  CT DE ME MD MA NH NJ NY PA RI VT

Projection and 50-state downscaling methodology

Carbon dioxide emissions

Projected CO_2 emissions from all energy use in RHG-NEMS are inconsistent with EPA's accounting conventions for CO_2 from fossil-fuel combustion in its GHG inventory. To address this inconsistency, we make the following adjustments to RHG-NEMS output to generate a forecast for CO_2 from fossil-fuel combustion:

- **INTERNATIONAL BUNKER FUELS:** Emissions from fuel combustion by ships and airplanes that depart from or arrive in the US from international destinations are not included in EPA's inventory of total US emissions, nor are they counted in US climate targets. However, they are included in RHG-NEMS CO_2 output. We subtract these emissions from our projections.

- **INDUSTRIAL NON-ENERGY USE OF FUELS:** Fossil fuels are used as feedstocks in the manufacture of a variety of products, such as steel and chemicals. Generally, EPA accounted for CO_2 emissions generated by consumption of these feedstocks in the industrial processes categories of the GHG inventory, not under fossil-fuel combustion CO_2. We subtract CO_2 emissions from non-energy uses of CO_2 from our fossil-fuel combustion projections and account for non-energy use of fuels and feedstocks elsewhere.

- **TRANSPORTATION NON-ENERGY USE OF FUELS:** A small amount of petroleum fuel used in the transportation sector (largely for lubricants) is not combusted but generates CO_2 emissions through its usage. We subtract this amount from projections of petroleum CO_2 emissions in the transportation sector and account for them elsewhere as non-energy use of fuels.

RHG-NEMS does not provide an Intergovernmental Panel on Climate Change (IPCC) consistent projection output for non-fossil fuel consumption CO_2 emissions from activities such as non-energy use of fuels and industrial processes. We applied the following methods to project non-fossil fuel combustion CO_2 emissions:

- **INVENTORY CATEGORIES WITH EMISSIONS BELOW 25 MILLION METRIC TONS (MMT):** We extrapolate historical trends from (CGS)' latest GHG inventory in line with EPA's GHG projection guidance.

- **INVENTORY CATEGORIES WITH EMISSIONS ABOVE 25 MMT:** We follow EPA's latest guidance, scaling inventory data based on category-appropriate RHG-NEMS output. For example, recent historical CO_2 emissions from natural gas systems are scaled based on the projected change in dry natural gas production available at the play level from RHG-NEMS. This allows for non-combustion CO_2 emissions to change in line with changes in the economic and technology assumptions we make to account for uncertainty in our projections.

Non-CO_2 and land use emissions and removals

All projections of non-CO_2 emissions (i.e., methane, nitrous oxide, hydrofluorocarbons, perfluorocarbon, and sulfur hexafluoride) follow the same general approach as we take in projecting CO_2 emissions from non-fossil fuel combustion sources. Inventory categories with emissions less than 25 mmt CO_2-e are extrapolated based on recent historical trends. Inventory categories with emissions more than 25 mmt CO_2-e are scaled based on appropriate outputs from RHG-NEMS where possible. In some instances, such as agriculture, there are no appropriate outputs from RHG-NEMS to scale emissions. In these instances, we use alternative public projections such as the US Department of Agriculture (USDA)'s long-term projections. Additional modifications are made to reflect the impact of state and federal policies as discussed above.

Historical emissions and removals from land use, land-use change, and forestry (LULUCF) come directly from the 2024 CGS GHG inventory. Projected trends come from the high sequestration scenario from the 2022 Fifth Biennial Report of the United States calibrated to align with (CGS)' 2024 inventory. For emissions of N2O and CH4 from LULUCF, we assume 2024 emissions from LULUCF remain constant through 2040, following the approach used in the 2022 Biennial Report.

Downscaling national emissions projections to the state level

RHG-NEMS forecasts fuel consumption by sector at various levels of geographical aggregation, which is then downscaled to the state level using state-level activity data. For the power sector, generation-based emissions are taken directly from RHG-NEMS, which reports individual plant-level emissions. NEMS builds new fossil fuel-fired plants to meet electricity demand, and those plants and their respective emissions are attributed to individual states within an electricity market region based on historical trends. We estimate generation-based power emissions based on the production of electricity within a state, a portion of which may be exported outside the state. We also estimate power sector emissions associated with the consumption of electricity within a state, accounting for the carbon intensity of the generation that produced that electricity.

Projections of fuel consumption by other end-use sectors, including industry, buildings (a combination of the residential and commercial sectors), and transportation, are downscaled to the state level from nine census-level regions. In the building sector, we apportion census-level GHG emissions to constituent states using each state's share of historical fuel consumption. In the transportation sector, we use historical demand to allocate fuel consumption by mode in each census region between constituent states. For example, we use the historical share of vehicle miles traveled for LDV fuel demand, and truck ton-miles for freight fuel demand. For industry, we use EPA's Facility Level Information on Greenhouse Gases Tool (FLIGHT) as weights to apportion census region GHG emissions to constituent states for large industrial facilities, and total value-added as weights to apportion census region fuel consumption for smaller facilities.

For non-fossil fuel combustion CO_2 emissions at the state level, all other GHG emissions, and LULUCF emissions and removals, we use activity data from RHG-NEMS where available. For example, methane emissions from fossil fuel production are downscaled based on production output from RHG-NEMS, which is available by fuel basin/play and can be attributed to individual states. In cases where there are no appropriate outputs from RHG-NEMS, we draw on other sources of activity data, including FLIGHT, the EIA, and USDA.