Retail Rate Projections for Long-Term Electricity System Models

Patrick R. Brown, Pieter J. Gagnon, J. Sean Corcoran, and Wesley J. Cole

National Renewable Energy Laboratory

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List of Abbreviations and Acronyms

ADIT	accumulated deferred income taxes
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BA	balancing area
CAPEX	capital expenditures
D&A	distribution and administration
D/A/T	distribution, administration, and intra-regional transmission
DER	distributed energy resource
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
FOM	fixed operations and maintenance
G&T	generation and transmission
IOU	investor-owned utility
ISO	independent system operator
ITC	investment tax credit
kW	kilowatt
kWh	kilowatt hour
MACRS	modified accelerated cost recovery system
MBE	mean bias error
MMBtu	million British thermal units
MWh	megawatt hour
NEMS	National Energy Modeling System
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
OPEX	operational expenditures
PTC	production tax credit
PV	photovoltaics
ReEDS	Regional Energy Deployment System
reV	Renewable Energy Potential
rMBE	relative mean bias error
RPS	renewable portfolio standard
US	United States of America
VOM	variable operations and maintenance
VRE	variable renewable energy
WACC	weighted average cost of capital

Abstract

Electricity prices reported in many electricity-system planning studies leave out multiple price components and do not translate into retail rates, making it difficult to interpret how projected electricity system changes will impact costs to consumers. Full transmission costs are left out of many studies; distribution and administration costs are similarly excluded or highly simplified. Here, we present a detailed bottom-up accounting method for projecting future retail electricity rates in the United States. Making the simplifying assumption that each state is served by an investor-owned utility (IOU), we translate projected generation and transmission capacity and costs from the Regional Energy Deployment System (ReEDS) capacity-expansion model into IOU balance sheet expenditures, accounting for depreciation, taxes, and the breakdown between operating and capitalized (rate-based) expenses. Distribution, administration, and intra-regional transmission costs are projected forward based on empirical trends over the past decade. Modeled bottom-up electricity rates are compared to historical rates from 2010–2019, and the sensitivity of modeled rates to a range of financing and modeling assumptions is explored. Rate components associated with distribution, administration, intra-regional transmission, and transmission operations and maintenance account for roughly 59% (6.6 ¢/kWh) of the projected national-average retail rate over 2020–2050 under central assumptions.

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1 Introduction

The development and evolution of electricity generation technologies, fluctuations in fuel prices, electrification of end-use energy services, decentralization of electricity generation, and changing climate and policy landscape all lead to uncertainty in the evolution of the power system and an interest in identifying key contributors to the future technology mix, overall system cost, and cost to consumers. Electricity costs [$/MWh or ¢/kWh] are a common metric reported from models used to simulated the evolution of the power system (Ringkjøb, Haugan and Solbrekke, 2018), but many such models only capture a subset of power system costs. As such, electricity costs reported in many electricity-system planning studies do not translate into retail rates paid by consumers, making interpretation and comparison to historical prices difficult.

In this work we present and document a detailed bottom-up accounting method for projecting future retail electricity rates in the United States (US) by combining a sequential-investment capacity-expansion model with inter-annual cost-recovery accounting. Making the simplifying assumption that each state in the contiguous US is served by an investor-owned utility (IOU), we translate projected generation and transmission capacities and costs from the National Renewable Energy Laboratory (NREL) Regional Energy Deployment System (ReEDS) model (Ho *et al.*, 2021) into IOU balance sheet expenditures, accounting for the distinction between operational and capitalized (or "rate-based") expenditures, depreciation schedules, taxes, and other components. Distribution, administration, and intra-regional transmission costs are projected forward based on empirical trends over the past decade. We compare bottom-up modeled rates for 2010–2019 to historical retail rates from EIA Form 861 and perform a sensitivity analysis over key cost and accounting assumptions. The retail-rate projection method is applied for a collection of scenarios from the NREL 2021 Standard Scenarios report (Cole *et al.*, 2021), resulting in projections of annual US retail rates through 2050 under current policy conditions.

2 Methodology

2.1 Overview

The retail-rate accounting methodology reported here is designed for the NREL ReEDS model; a similar method can be applied to any sequential-investment capacity-expansion model with sufficient resolution. ReEDS is a capacity-expansion model for the interconnected power system of the US, Canada, and Mexico, designed to identify cost-minimizing capacity investment and operations decisions meeting electricity demand at the balancing-area (BA) level from 2010–2050 under a range of input assumptions. ReEDS allows considerable flexibility in spatial scope, temporal resolution, long-term foresight, and demand flexibility; in this work we consider the contiguous US in 2-year increments with no inter-annual foresight of demand, costs, technology parameters, or policies. The ReEDS model is described in detail by Ho et al (Ho *et al.*, 2021), with results for a variety of input assumptions described in the yearly Standard Scenarios reports by Cole et al (Cole *et al.*, 2021). We use the "Mid" case from the 2021 Standard Scenarios report unless noted otherwise.

Three commonly stated objectives of retail rate design are: achieving cost recovery for the utility (that includes an appropriate rate of return); incentivizing economic efficiency by designing rates that reflect how costs are induced; and fairly distributing costs across customers (considering distributional equity, cost causality, and other factors) (Wood *et al.*, 2016). A large body of literature addresses the latter two considerations (including features such as time-varying rates, combinations of fixed and volumetric rate components, peak-demand charges, demand-based rate tiers, etc.), particularly in the context of increasing deployment of distributed energy resources (DERs) (Satchwell, Mills and Barbose, 2015b; Pérez-Arriaga *et al.*, 2016; Satchwell, Cappers and Barbose, 2019; Burger *et al.*, 2020). We do not address these issues here, instead focusing on the first consideration; we calculate annual revenue targets and implied state- and US-average ¢/kWh rates without applying a specific tariff structure. We also do not consider in detail the potential response of retail rates to growth in the deployment of distributed photovoltaics (PV) (Darghouth, Barbose and Wiser, 2014; Satchwell, Mills and Barbose, 2015a; Barbose, 2017) or other behind-the-meter generation technologies.

In the model presented here, the retail rate [¢/kWh] is given by the revenue target for the state IOU divided by the annual retail electricity demand within the state, where the revenue target is given by the sum of operating expenses, the return to capital, and income taxes, and demand is exogenously defined with no lost load or price-responsive demand. For simplicity, the entire annual revenue target (including all pass-through expenditures and equity returns) is assumed to be completely recovered through the retail rate in each year. We first describe the sources for the capital and operating costs included in the model, then describe the allocation of these costs into specific accounting expenditures.

2.2 Cost components

Cost components include capital expenditures (CAPEX) and operational expenditures (OPEX) for generation, transmission, distribution, and administration; inter-regional trades; and taxes. All monetary values in this work are given in 2019 US dollars.

2.2.1 Generation

Generation CAPEX is derived from two sources. Historical capacity built from 2010–2019 and projected capacity built from 2020–2050 is provided by the ReEDS model, with annual cost assumptions taken from the NREL Annual Technology Baseline (ATB) 2021 (National Renewable Energy Laboratory, 2021). Capacity and construction dates before 2010 are taken from the Energy Information Administration (EIA) National Energy Modeling System (NEMS) database (U.S. Energy Information Administration, 2020). As a simplifying assumption, ReEDS/ATB technology-specific CAPEX cost assumptions for 2010 are applied to all capacity built before 2010. Scrubber costs and installation years for coal plants are similarly taken from the EIA-NEMS database; for coal units that report a scrubber installation but do not report the scrubber cost [$/kW], we apply the average scrubber cost from units that do report a scrubber cost.

Generation OPEX includes multiple components, all derived from ReEDS model outputs: fixed operations and maintenance (FOM), fuel, variable operations and maintenance (VOM), operating reserves, and alternative compliance payments (ACP) for state renewable portfolio standards. FOM costs are separated into capitalized (e.g. capital assets whose costs are recovered through depreciation over time, such as module replacement for a PV plant, or boiler replacement for a thermal plant) and non-capitalized (e.g. expenses that are not capital assets, such as maintenance labor) costs, which are treated separately in the accounting procedure detailed below. FOM [$/kW], VOM [$/MWh], and fuel [$/MMBtu] cost projections are taken from the NREL ATB (National Renewable Energy Laboratory, 2021), which bases its fuel-price projections on the EIA Annual Energy Outlook (U.S. Energy Information Administration, 2021b). The ReEDS model implements technology-specific costs for the provision of operating reserves [$/MWh], with numeric values given in Ho et al (Ho *et al.*, 2021).

Alternative compliance payments for unmet renewable portfolio standards (RPS) are applied at the state level (NC Clean Energy Technology Center, 2020; Ho *et al.*, 2021).

2.2.2 Transmission

Transmission capacity includes spur lines for wind and solar generators, substations, inter-BA transmission lines, and intra-BA transmission. Spur line costs for tens of thousands of candidate wind and solar sites are calculated in the NREL Renewable Energy Potential (reV) model (Maclaurin *et al.*, 2019) and used as inputs to ReEDS; spur line costs for constructed sites are then obtained from ReEDS outputs. Inter-BA transmission capacity is obtained from ReEDS projections, with cost assumptions taken from the Phase II Eastern Interconnection Planning Collaborative report with regional multipliers (EIPC, 2012). The cost of each inter-BA line is evenly split between the BAs it connects. Inter-BA transmission lines incur an additional voltage-dependent substation cost, drawing from a supply curve of available substation capacity and cost by voltage within each BA. Existing transmission capacity is assumed to have been built uniformly over the previous 40 years using the same cost [$/kW-km] as new transmission in ReEDS.

Intra-BA transmission capacity and cost (aside from wind/solar spur lines and substations, discussed above) are not directly modeled in ReEDS. To estimate intra-BA transmission costs we first obtain transmission CAPEX expenditures by IOU from the ABB Velocity Suite database of Federal Energy Regulatory Commission (FERC) Form 1 responses from 2010–2019 (U.S. Federal Energy Regulatory Commission, 2019; ABB, 2020), using the “additions” data for transmission plants within the “Electric Plant in Service” schedule. We aggregate annual transmission CAPEX spending for IOUs in FERC Form 1 by IOU state headquarters to the regions shown in Figure A1 in the Appendix, roughly corresponding to Independent System Operator (ISO) coverage areas; we assess transmission CAPEX at the regional level to reflect the coordinated nature of transmission planning within ISOs and the limited coordination between ISOs. ReEDS expenditures for spur lines, substations, and inter-BA transmission (discussed above) are aggregated to the same regional areas and subtracted from FERC-reported transmission CAPEX, leaving a residual of regional transmission CAPEX costs that are reported to FERC but unaccounted for by ReEDS. Electricity sales by IOU are similarly obtained from FERC Form 1, using the “Total Retail Sales MWh” data from the “Electric Operating Revenues” schedule.[1] Annual intra-regional transmission CAPEX is then divided by annual regional electricity sales to obtain annual transmission costs in ¢/kWh over 2010–2019.

2.2.3 Distribution & Administration

Transmission OPEX, distribution CAPEX and OPEX, and administration CAPEX and OPEX are obtained in a similar manner to intra-BA transmission CAPEX, albeit without subtracting any ReEDS cost components (because ReEDS does not include these costs). Annual distribution CAPEX spending by IOU is taken from the “Additions” data for “Total distribution plant” within the “Electric Plant in Service” schedule of FERC Form 1; administrative and general (hereafter shortened to “administration” or “administrative”) CAPEX is taken from the “Total General Plant” entry in the same schedule. Annual transmission OPEX spending by IOU is taken from the “Total Transmission Expenses” entry in the

[1] For three utilities—Central Maine Power Co., Dixie Escalante Rural Electric Association Inc., and Salmon River Electric Coop Inc.—annual sales are instead taken from EIA Form 861 (U.S. Energy Information Administration, 2021a) due to inconsistencies in FERC Form 1 data.

“Electric Operation and Maintenance Expenses” schedule of FERC Form 1; distribution OPEX is taken from the “Total Distribution Expenses” in the same table; administrative OPEX is taken from the sum of the “Total Administrative & General Expenses”, “Total Sales Expenses”, “Total Customer Service and Information Expenses”, “Total Customer Accounts Expenses”, and “Total Regional Transmission and Market Operation Expenses” entries in the same table.

An adjustment is made to administrative OPEX expenses for two utilities: Pacific Gas & Electric Co. and Southern California Edison Co. These utilities report large operating expenses in the “Injuries & Damages” entry in the “Electric Operation and Maintenance” schedule in 2018 and 2019 associated with California wildfires in 2015–2018. Rather than passing these expenses directly through to retail rates in 2018–2019, we assume these costs are recovered as yearly annuities over the 15 years following the year in which they are incurred (California Legislature, 2019). Using the weighted average cost of capital (WACC) assumptions noted below, the combined \$20.5 billion in expenses for these utilities over 2018–2019 is amortized into a total of \$27.5 billion recovered over the following 15 years.

While transmission CAPEX is most appropriately aggregated across IOUs at the regional level, distribution and administration CAPEX and OPEX and transmission OPEX would most naturally be aggregated at the state level (the finest spatial resolution that can be inferred from the entries in FERC Form 1). However, the data in FERC Form 1 are not comprehensive; for some states (particularly those with a greater proportion of demand served by non-IOU entities) the data reported by IOUs in FERC Form 1 represent a small fraction of total retail demand in the state (as low as 0.1% for Utah in 2011, an outlying example). For these states the small sample size is likely to lead to errors in the calculated distribution, administration, and transmission rate components, and aggregating IOU expenditures and sales at the regional or national level would give a closer estimate of the actual rate contributions [¢/kWh] of these components in these states. We therefore calculate the ¢/kWh rate contributions for distribution CAPEX and OPEX, administration CAPEX and OPEX, and transmission OPEX by aggregating the data in FERC Form 1 across IOUs at three different levels of aggregation (state, region, and nation), calculating the complete retail rate for each state, and comparing the calculated state retail rate in 2010–2019 to the historical annual state retail rate reported in EIA Form 861 (U.S. Energy Information Administration, 2021a). The aggregation level (state, region, or nation) that minimizes the mean bias error (MBE) over 2010–2019 for each state is then used when calculating ¢/kWh rate contributions for distribution CAPEX/OPEX, administration CAPEX/OPEX, and transmission OPEX in the rest of this study. The results of the comparison against EIA Form 861 rates are provided below in Section 3.1.

2.2.4 Projection of Distribution, Administration, and Transmission Components

The contribution of distribution, administration, and intra-regional transmission (D/A/T) components to retail rates has been changing over time, and the future evolution of these components is uncertain. As ReEDS does not directly model these components, projections for D/A/T components are generated by projecting recently observed component rates in ¢/kWh into the future. Projections are generated by fitting a line to the most recent α years of historical D/A/T rates (calculated as described in the previous section) and projecting the observed slope forward in time, uniformly reducing the slope over the next β years to zero. In the central case we use the most recent 10 years to determine the slope ($\alpha = 10$) and uniformly reduce the slope over the next 10 years ($\beta = 10$), such that D/A/T rates in ¢/kWh saturate in 2029. Different choices for the α and β parameters are explored in the sensitivity analysis as discussed below. The saturation level should not be interpreted to mean that D/A/T rates stop changing after β

years; it should instead be interpreted as an estimate of the center of an unknown probability distribution of potential future rates.

2.2.5 Interregional expenditure flows and tax credits

Inter-BA flows and accompanying expenses are tracked for energy, operating reserves, planning reserves, and RPS credits. Energy flows are also tracked between Canada and adjacent BAs in the US; when running the US-only version of ReEDS (which is the version used in this work) these flows are exogenous model inputs rather than optimized model outputs. Flows are tracked as the price of the product (energy, reserves, or RPS credits) in the receiving BA multiplied by the quantity of the product transferred between BAs. Inter-regional expenditure flows are treated as operating expenditures in the importing BA and credits in the exporting BA, increasing the revenue target (and associated retail rate) in the importing BA and reducing the revenue target in the exporting BA.

The ReEDS model includes federal tax incentives—the investment tax credit (ITC) and production tax credit (PTC)—according to current schedules as of November 2020. These tax credits reduce generation CAPEX/OPEX expenditures, thereby reducing utility expenditures and associated revenue targets and retail rates. The cost to the federal government of these tax incentives is not included in the rates reported here.

2.3 Accounting methods

The previous section described the various types of costs incurred when building and operating the electric sector. Here we describe the accounting methods that we employ to translate yearly costs into estimates of the revenue to be collected from retail customers through electric bills. This approach is a simplified version of actual accounting practices for IOUs in the US—in practice, the accounting for utilities is more complex than the procedure described here.

The output of this accounting step is a utility's annual revenue target—the amount of revenue that it would collect from ratepayers to cover its costs while achieving a target return to capital. We describe the accounting process by grouping the various costs into three categories: operational expenses, return to capital, and income taxes. Figure 1 shows an outline of the accounting method.

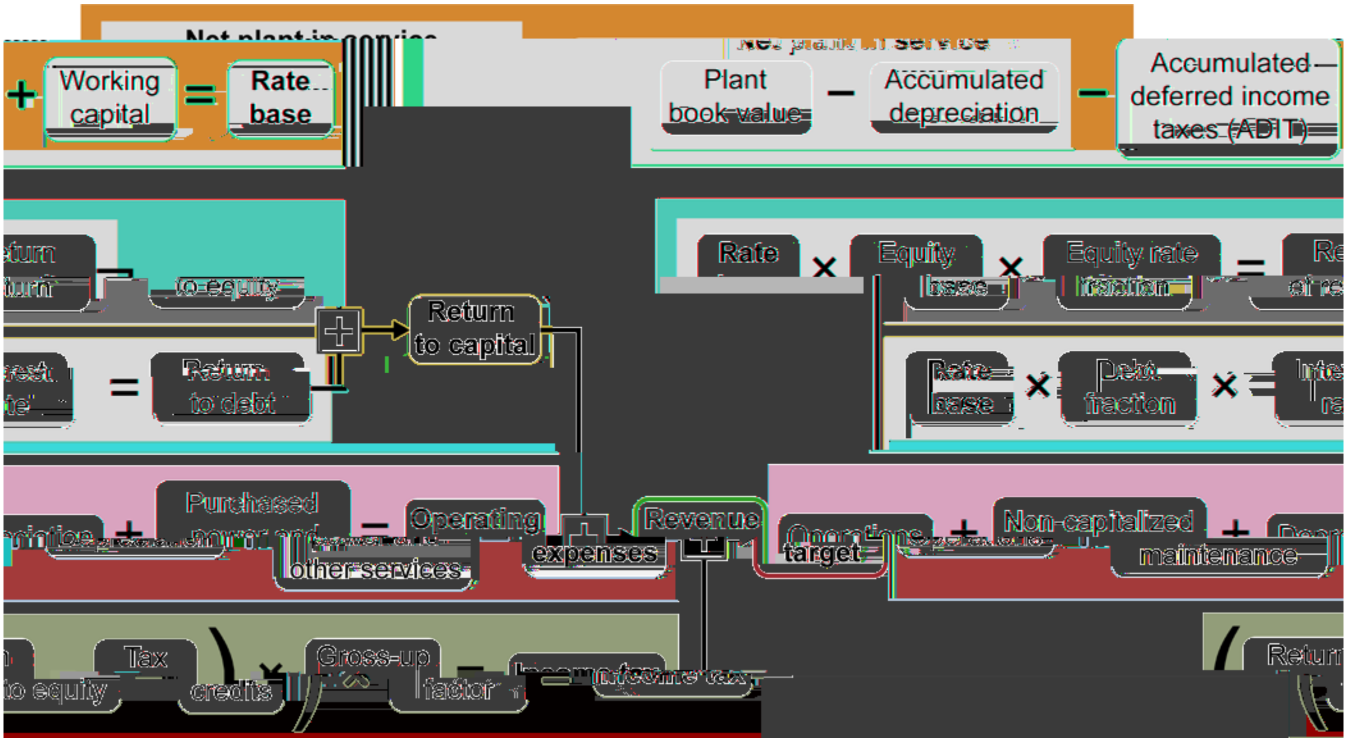


Figure 1. Overview of the accounting structure for an investor-owned utility (IOU).

Electricity rates [¢/kWh] in this work are given by the revenue target divided by retail electricity sales.

2.3.1 Operating expenses

The first of the three categories is operating expenses. Operating expenses include all of the OPEX categories listed in the previous section (generation, distribution, transmission, and administrative OPEX), the depreciation of capital assets, and the costs of inter-state trading. For all of these expenses, we assume that each year's expense is directly passed through to ratepayers during the year in which it is incurred. For example, if all operating expenses in a given year sum to $100 million, the ratepayers will pay $100 million that year to cover those costs.

We assume that all depreciation schedules for cost recovery are straight-line over an assumed lifetime of the capital asset.[2] The annual depreciation expense for each capital asset is therefore the original book value of the capital asset for each utility, divided by the initial assumed lifetime of the asset. For example, if a $10 million capital asset is assumed to last for 10 years, then there will be a $1 million depreciation expense during each of those initial 10 years, after which the asset is fully depreciated. Generation asset lifetimes are taken from ReEDS, and the lifetimes of other capital assets are given in Table 1. The recovery of capital expenditures through depreciation expenses has the effect of allocating capital expenditures over time. The accumulated depreciation for each capital asset ties into the rate base, which is described below.

[2] Depreciation schedules for tax purposes can differ from depreciation schedules for recovering depreciation costs, leading to an accumulated deferred income tax liability. This component is explained further in Section 2.3.2.

Table 1. Assumed numerical values for accounting assumptions.

Input parameter	Value	Units
Working capital as multiple of daily OPEX	45	days
FOM capitalization percentage	50	%
Timeline for existing transmission construction	40	years
D/A/T slope fit years (α)	10	years
D/A/T slope decay years (β)	10	years
Evaluation period, capitalized FOM	20	years
Evaluation period, spur lines	20	years
Evaluation period, inter-BA transmission	30	years
Evaluation period, VRE interconnection	30	years
Evaluation period, substations	30	years
Evaluation period, initial transmission CAPEX	30	years
Evaluation period, distribution CAPEX	20	years
Evaluation period, administrative CAPEX	20	years
Evaluation period, wildfire lawsuits	15	years
Depreciation schedule	20	years
Debt fraction, post-2020	55	%
Equity return rate (nominal), post-2020	9.6	%
Debt interest rate (nominal), post-2020	3.9	%
Federal tax rate, post-2020 (T)	21	%

2.3.2 Return to capital

The second of the three expense categories is the return to capital, i.e. the compensation to shareholders and debtholders. The return to capital is driven primarily by a utility's rate base. In our accounting, the rate base is composed of the total net plant in service, plus working capital, minus any accumulated deferred income taxes. We describe each of these components here.

First, every capital asset has a net plant in service dollar value, where "plant" is a generic reference to a capital asset. A capital asset's net plant in service is the original book value of the capital asset, minus the accumulated depreciation (described previously in Section 2.3.1) for that capital asset up to that point—a $500 million generator that has been depreciated $100 million would have a $400 million net plant in service. Once a capital asset has fully depreciated its book value, it no longer contributes to the rate base. In our implementation, the original plant investment, ongoing capitalized maintenance expenses, retrofits, and rebuilds are all tracked as separate investments, and can have their own depreciation schedules if warranted. As mentioned in Section 2.2, generation and inter-BA transmission assets are explicitly modeled by ReEDS, whereas we use historical and projected utility expenditures from FERC Form 1 (U.S. Federal Energy Regulatory Commission, 2019) to estimate annual expenditures for distribution and administrative capital assets.

The capital assets are the primary component of the rate base, but working capital is a component as well. Working capital is the net value of current assets minus current liabilities that the utility needs to conduct its operations—for example, the value of on-site fuel stocks and cash balances to manage day-to-day expenses. As with capital assets, working capital earns a return, and therefore it is added to the rate base. We estimate the total amount of working capital as the equivalent of 45 days of all operating expenses (i.e., 45/365 × annual operating expenses).

Lastly, any accumulated deferred income taxes (ADIT) are subtracted from the rate base. ADIT is the total value of any deferred income taxes, e.g. from using a faster depreciation schedule for tax purposes than was used for calculating annual depreciation expenses (explained previously in Section 2.3.1). Incentives that act to delay income taxes (such as the accelerated depreciation schedules of the Modified Accelerated Cost Recovery System, MACRS) can be interpreted as an interest-free loan from the government. In regulated utility rate-making, it is recognized that ratepayers should not have to pay a return to capital if the source of the capital is (effectively) an interest-free loan from the government. Therefore, the value of these deferred income taxes is subtracted from the rate base.

These three components (net plant in service, working capital, and ADIT) make up the rate base. We assume that the rate base represents the total amount of capital required by the utility, which is composed of both debt and equity. Therefore, we calculate how much equity and debt is required (with assumed debt and equity fractions), and a return to each source of capital based on assumed nominal rates. For example, if a utility has a $1 billion rate base, with 55% debt fraction and a nominal interest rate of 3.9%, the interest payments to that debt that year would be $21.45 million (assuming the debt was issued at par value).

Rates of return to equity, interest rates for debt, and debt fractions are taken from Table 3 in Feldman et al (Feldman, Bolinger and Schwabe, 2020) for 2010 to 2019, which is based on historical data reported by the Edison Electric Institute (Edison Electric Institute, 2019). The 2019 values are used for 2020 and beyond unless noted otherwise.

2.3.3 Income Taxes

The last of the three expense categories is federal income taxes. In practice a corporation would calculate their net income to determine their income tax burden—however, we make the assumption that the only class of revenue collection that is not exactly offset by an equal expense is the return to equity, which greatly simplifies our accounting.

Employing this assumption, we start with the year's calculated return to equity, explained previously. We then subtract any income tax credits claimed that year. To calculate the amount of income taxes that would be levied, we multiply the resulting value by $\frac{1}{1-T} - 1$, where T is the effective tax rate. The result is the additional amount of revenue that would need to be collected and directed towards income taxes, to maintain the target return to capital while also covering costs.

2.4 Limitations and simplifying assumptions

Before discussing our results, we first note a number of limitations and simplifying assumptions.

As noted above, distribution, administration, transmission O&M, and intra-regional transmission CAPEX costs are projected forward as ¢/kWh rate adders. Fares and King (Fares and King, 2017) found that $/customer and $/kW-peak metrics give higher-quality fits to historical IOU expenditures than a ¢/kWh metric; however, the ReEDS model does not model individual IOU service territories or shifting population dynamics, so we are confined to a ¢/kWh metric. We also do not directly model the impact of accelerated deployment of behind-the-meter DERs (typically PV) or electrification of end-use services and transportation on distribution rates—although to the extent to which such trends have impacted distribution system costs over the past 10 years, they will be reflected in our projected distribution rates. These and other demand-side trends lead to changes in the peak-to-mean demand ratio on the distribution grid and could increase the deviation between ¢/kWh, $/kW-peak, and $/customer metrics. Distributed PV in particular can either increase or decrease distribution system costs depending on feeder-specific conditions that are beyond the scope of the model used here (Schmalensee *et al.*, 2015).

We make the simplifying assumption that each state is served by an IOU. IOUs served roughly 72% of electricity customers in the US in 2017 (U.S. Energy Information Administration, 2019), with most of the remainder served by cooperatives and publicly-owned utilities. Non-IOU entities would have different (likely higher) costs of capital (U.S. Environmental Protection Agency, 2018); as shown in Figure 7 below, calculated rates are particularly sensitive to financial assumptions. The FERC Form 1 data used here to determine distribution, administration, and intra-regional transmission rates are only reported for IOUs, and it is possible that these rate components could differ systematically for non-IOU entities.

We do not model policy-driven decarbonization, instead utilizing central cases from the NREL Standard Scenarios report. However, the model described here could be directly applied to a decarbonized system with appropriate choices for ReEDS input parameters.

The ReEDS model and our retail rate calculations do not include a quantification of environmental, public health, and climate externalities. We also do not include the effects of local incentives or state income taxes.

Our representation of the accounting to derive annual revenue targets for each state is also a simplification of actual accounting practices. For example: construction work-in-progress is neglected from the rate base; certain classes of current liabilities and assets (such as customer pre-payments, accounts payable, accounts receivable) are ignored; the PTC is assumed to pass through directly to the ratepayers without any normalization; and the full cost of new capital assets is depreciated over a single assumed lifetime (instead of different lifetimes for different components of the capital expense, such as the land, office building, and plant of a new generation facility).

In addition to the simplifications involved in calculating the annual revenue target, we also make the simplifying assumption that the revenue target is exactly achieved each year—i.e., all costs are exactly recovered each year. In practice, deviations from perfect cost recovery can have meaningful implications for utility profitability, although this simplification is less influential on estimating retail rates. Relatedly, we also implicitly assume that costs are covered by ratepayers, neglecting some instances where utilities receive funds from other sources, such as insurance payouts or government transfers.

In sum, the data processing and methodology described here were designed primarily to estimate an annual revenue target (and therefore the average cost of electricity to ratepayers) based on a stylized representation of IOU-style accounting. As a result, this method is not appropriate for investigating certain types of questions—it cannot characterize how an intervention would impact utility shareholders, for example, because it assumes perfect cost recovery every year. As with any model, users are encouraged to critically assess whether the approach taken here sufficiently resolves the most critical aspects of the ratemaking process for any new application of the methodology.

2.5 Alternative Cost Metrics

The methodology presented above describes how the retail rate metric is developed. Other common cost metrics employed by capacity expansion models include the marginal electricity cost and the annual system cost. In Section 3.4 we compare the retail rate metric to these other two metrics.

The marginal electricity cost is calculated using the shadow prices from the constraints within the model that are tied to electricity consumption. For ReEDS, these constraints include the load balance constraint (supply must be equal to demand), the operating reserve requirement, the RPS and clean energy standard requirements, and the planning reserve margin. The marginal electricity cost is calculated as:

$$\frac{\sum_{i,h,r} Requirement_{i,h,r} \cdot ShadowPrice_{i,h,r}}{\sum_{r,h} Load_{r,h}}$$

where *i* are the constraints listed above, h are the time periods represented in the model, and *r* are the model regions. Thus, the marginal electricity cost reflects the cost of purchasing the required services at the marginal price reflected in the model, normalized by the total load.

The annual system cost is the annualized total system cost divided by the total load. The system cost includes all capital and operating costs incurred in the model, leaving out the capital cost of "brownfield" assets built before 2010, the first modeled year. The capital costs are annualized over the assumed 20-year book life of the power plants using a discount rate of 5%.

3 Results and Discussion

3.1 Comparison of modeled bottom-up retail rates to historical rates

As discussed in Section 2.2.3, estimates of D/A/T rate components aggregated from IOU expenditures at the state level are not reliable for all states given the incomplete coverage of state electricity demand by the entities with expenditures reported in FERC Form 1. Figure 2 displays historical state electricity rates from EIA Form 861 (U.S. Energy Information Administration, 2021a) alongside our bottom-up estimates of state electricity rates from 2010–2019, with D/A/T rates for each state calculated from FERC IOU data aggregated at the state, regional, and national level. National aggregation implies a single value for distribution CAPEX/OPEX, administration CAPEX/OPEX, and transmission OPEX rates [¢/kWh] across all states; total state rates still vary in this case due to differences in generation rates and inter-BA flows across states.

Figure 2. State-level comparison of modeled and historical electricity rates.

Each row displays the following information for a single state, from left to right: the historical retail rate (black solid lines, “EIA861”), calculated rate with national distribution, administration, and transmission (D/A/T) parameters (blue dash-dotted lines, “National”), calculated rate with regional D/A/T parameters (red dashed lines, “Regional”), and calculated rate with state D/A/T parameters (orange dotted lines, “State”) from 2010–2019, with 2010 at the top and 2019 at the bottom; the mean bias error between the lowest-error aggregation level and the historical rate in ¢/kWh; the relative percent bias error between the lowest-error aggregation level and the historical rate; and the aggregation level that gives the lowest mean bias error. States are organized in ascending order by the average historical retail rate over 2010–2019.

The D/A/T aggregation level that provides the best fit to historical rates varies across states: state-level aggregation minimizes the mean bias error (MBE) for 15 states, regional aggregation minimizes MBE for 17 states, and national aggregation minimizes MBE for 16 states. The relative mean bias error (rMBE) under the state-MBE-minimizing aggregation level ranges from –32% for New Jersey (NJ) to +56% for West Virginia (WV). Particularly under-estimated states (with ≤–15% rMBE) include Maryland (MD), New Jersey, California (CA), New York (NY), and Connecticut (CT); particularly over-estimated states (with ≥+15% rMBE) include Wyoming (WY), West Virginia and Iowa (IA).

Figure 3 shows the difference between our calculated electricity rates and historical rates across the US over the 10 years of overlapping coverage (2010–2019) for different choices of D/A/T aggregation level. Without bias correction, state aggregation gives the lowest overall error (-0.3 ¢/kWh MBE and -3% rMBE); however, as shown in Figure 2, it distorts the calculated rates for some individual states. Using the best (MBE-minimizing) aggregation level from Figure 2 for each state gives an uncorrected error of –0.6 ¢/kWh MBE and –5% rMBE; subtracting the state MBE from the calculated rate for each state nearly eliminates the error over the US as a whole, as expected (+0.02 ¢/kWh MBE and +0.1% rMBE). While the nonzero state bias errors indicate that there are components of actual retail rates that are not captured in our bottom-up accounting, applying the state MBE values as a bias-correction factor approximates the influence of these residual components in projections of future retail rates, under the assumption that the state residuals stay constant in time. Except where noted otherwise, we apply the "best" aggregation level for D/A/T rates along with state bias-correction factors for all results discussed in the remainder of this study.

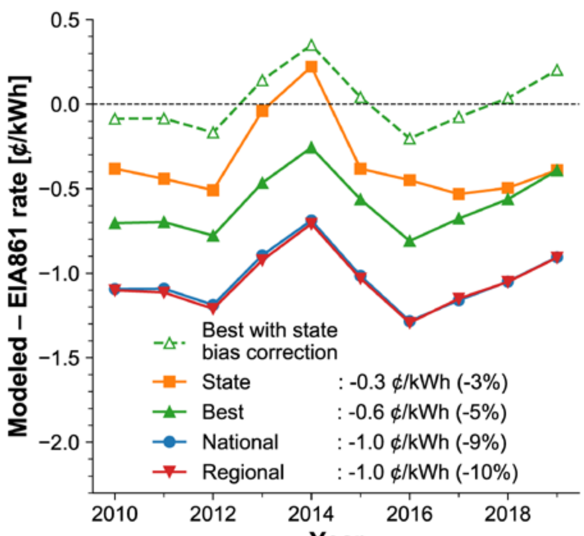


Figure 3. Comparison of modeled bottom-up electricity rates against observed historical rates across the US.

Difference between modeled and historical rates over overlapping years (2010–2019) using four different levels of aggregation for determining state-specific distribution, administration, and transmission O&M cost parameters from historical FERC Form 1 data: assigning the US-average parameters to all states ("National", blue circles), disaggregating cost parameters by region ("Regional", red downward triangles), disaggregating cost parameters by state ("State", orange squares), and disaggregated using the bias-minimizing aggregation level for each state listed in Figure 2 ("Best", green upward triangles). Two traces utilizing the "best" aggregation level are shown: filled green triangles indicate values without state bias-correction; empty green triangles indicate values with state bias-correction factors included. Bias-correction factors are not applied for the "State", "National", and "Regional" traces.

3.2 Retail rate projection under central assumptions

Figure 4 shows the central projection for US retail rates through 2050, using the D/A/T assumptions described in the previous section and the "Mid" case ReEDs assumptions from the 2020 NREL Standard Scenarios Report (Cole *et al.*, 2021), which assumes "moderate" cost trajectories from the 2021 Annual Technology Baseline (ATB) (National Renewable Energy Laboratory, 2021). Projected nationwide rates for 2020–2050 under these central assumptions are 11.3 ¢/kWh on average, roughly 10% lower than historically observed rates from 1960–2019.

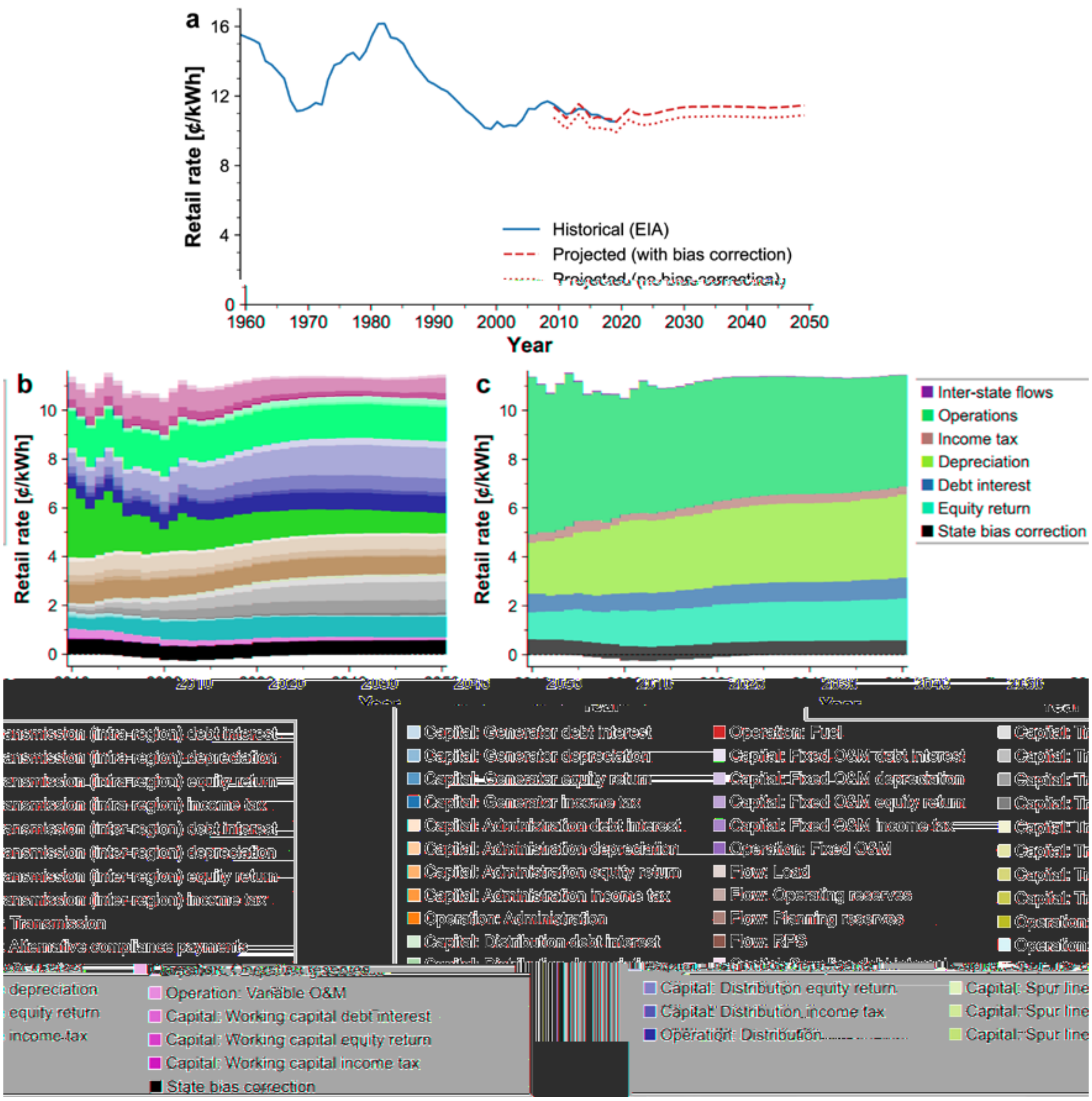


Figure 4. Projected US-average electricity rates under central assumptions.

a, Weighted-average retail rate projection over the continental US with (red dashed line) and without (red dotted line) state-level residual bias correction, compared to historical weighted-average US electricity rates from EIA Form 861 (blue solid line). **b**, Projected US retail rate disaggregated into individual cost components, organized by component class. **c**, Projected disaggregated US retail rate, grouped by financial cost type. The impact of federal tax credits (the ITC and PTC) is indicated in **b** and **c** by the small negative offset, peaking at -0.28 ¢/kWh in 2023.

Rate contributions from distribution and intra-regional transmission are projected to increase after 2020, while contributions from fuel and FOM costs are projected to decrease (Figure 4b).

Similar trends are observed when costs are grouped by financial type instead of by the cost-driving component (Figure 4c); depreciation expenses are projected to increase while operations expenses decrease. These trends are driven both by the recent trend toward increasing distribution and transmission costs and by the projected increase in fuel-free (solar, wind, hydropower, and geothermal) generation penetration under central cost assumptions (from ~17% of total generation in 2018 to ~52% in 2050) and concomitant decrease in fuel-based generation.

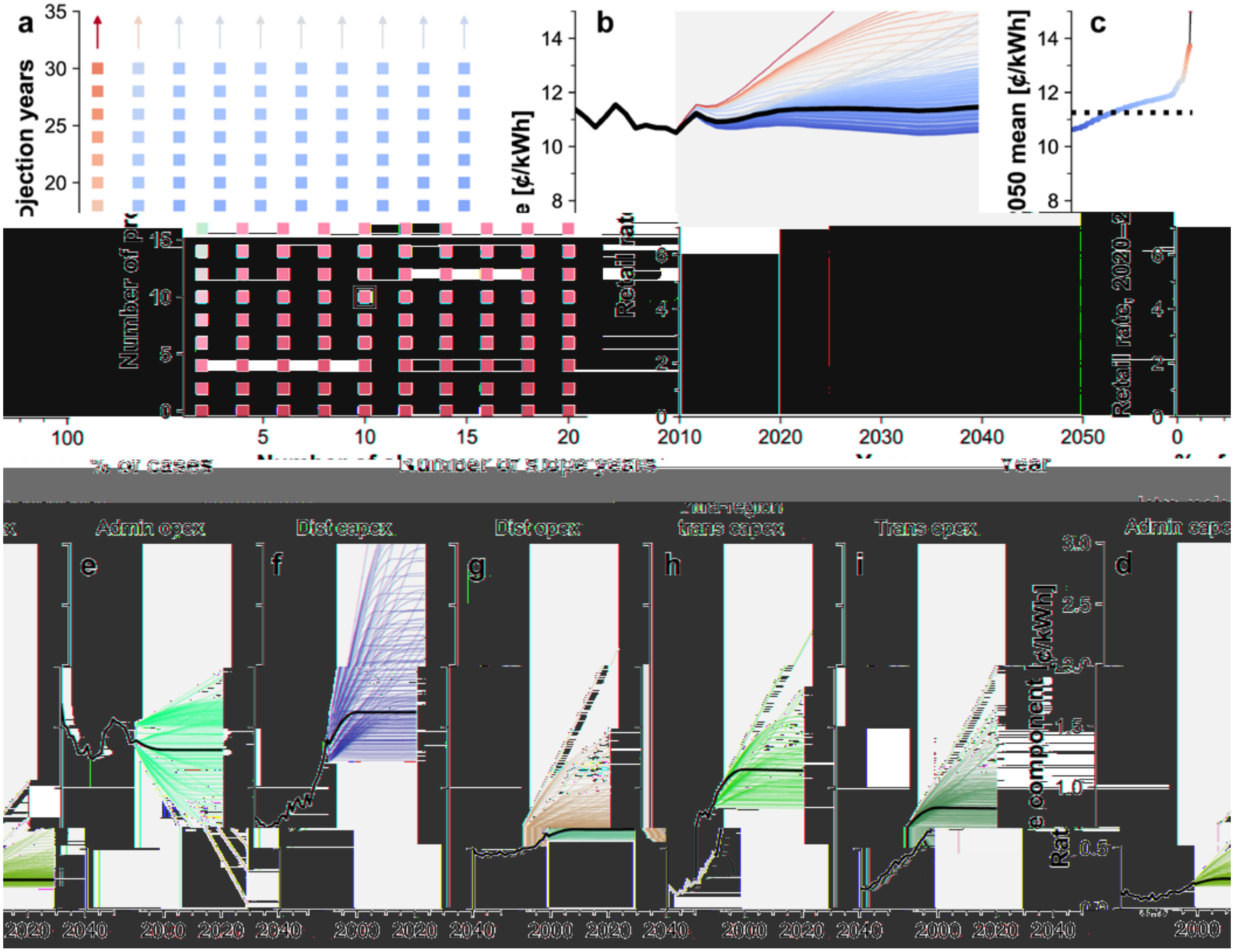
Figure 4b also illustrates the importance of rate components not captured by many capacity-planning models: Distribution, administration, intra-region transmission CAPEX, and transmission OPEX account for 59% (6.6 ¢/kWh) of the total retail rate on average over 2020–2050.

3.3 Sensitivity analysis

The results discussed thus far have used a single set of assumptions regarding the D/A/T projection, ReEDS scenario, and financing metrics. There is considerable uncertainty in all of these parameters. Here we explore the sensitivity of our retail rate projections to each of these assumptions.

3.3.1 Distribution, administration, and transmission component projections

As discussed in Section 2.2.4, projections for D/A/T rate components are generated by measuring the slope of each component in ¢/kWh over the past 10 years and projecting that slope forward, uniformly reducing the slope each year over the next 10 years (leading to saturation at a constant value in 2029). As the choice of a 10-year fit and 10-year slope decay is somewhat arbitrary, Figure 5 shows the sensitivity of projected retail rates to the number of years used to determine the slope (α) and the number of years until the slope declines to zero (β), with α ranging from 2–20 years and β ranging from zero years (indicating constant D/A/T rates at their average value over the past α years) to infinite years (indicating a constant projected slope with no decay) (Figure 5a). The projected US-average retail rate over 2020–2050 ranges from 10.6 ¢/kWh with $\alpha = 6$ and $\beta = 0$ (6% lower than the central projection with $\alpha = 10$ and $\beta = 10$) to 15.1 ¢/kWh with $\alpha = 2$ and $\beta = \infty$ (34% higher than the central projection). The 2020–2050 average retail rate under our central assumption of $\alpha = 10$ and $\beta = 10$ is within –2.3% (–0.3 ¢/kWh) of the median over the 170 (α,β) combinations shown in Figure 5a-c, suggesting it makes an appropriate central case for such projections.



a, Default values of slope-calculation (α) and slope-projection (β) years (black outlined square) and collection of alternative assumptions used in sensitivity analysis (colored squares). Additional cases with constant future slope (i.e., infinite projection years) are indicated by arrows at the top of the figure. **b**, US-average rate profile under central assumption (black line) and alternative sensitivity cases (colored lines). **c**, US-average rate over 2020–2050 under central assumption (black dotted line) compared with US-average 2020–2050 rates under sensitivity assumptions (colored squares) sorted in ascending order. Markers and lines in **a**-**c** are colored by US-average 2020–2050 rate shown in **c**. **d**-**i**, Individual rate components projected forward from FERC Form 1 data: administration CAPEX (**d**), administration O&M (**e**), distribution CAPEX (**f**), distribution O&M (**g**), intra-region transmission CAPEX (**h**), and transmission O&M (**i**). Intra-region transmission CAPEX (**h**) is aggregated at the regional level; other components are aggregated at the MBE-minimizing aggregation level for each state. As discussed in Section 2.2.2, projections for intra-region transmission CAPEX (**h**) only use data from 2010–2019, for which ReEDS and FERC data overlap; the gray line before 2010 indicates FERC-only data, which are not used in the projection. The gray filled areas in **b** and **d**-**i** indicate projected data. Black lines in **d**-**i** indicate values projected under central assumptions, with the slope fitted to the most recent 10 years and the projected slope saturating after the next 10 years; colored lines indicate values projected under the alternative projection/slope assumptions shown in **a**. Panels **b** and **c** use state bias correction factors; panels **d**-**i** present individual rate components without bias correction.

The individual D/A/T components exhibit noticeably different trends over the past 25 years, which translate into divergent trends across the different (α,β) combinations. Distribution CAPEX, intra-region transmission CAPEX, and transmission OPEX have increased fairly consistently over the observed historical period, leading to generally increasing projections through 2050, while administration CAPEX/OPEX and distribution OPEX have not changed as notably.

3.3.2 ReEDS scenarios and accounting assumptions

The annual NREL Standard Scenarios reports show the sensitivity of ReEDS capacity, operation, and energy price projections to a range of alternative input assumptions (50 scenarios in the 2021 report (Cole *et al.*, 2021)). Here we assemble 10 alternative scenarios from the 2021 Standard Scenarios report, emphasizing scenarios with the largest deviation in energy price from the reference case in order to explore the potential sensitivity of retail electricity rates to large-scale variations in electricity sector evolution. The scenarios selected here combine variations in renewable energy and battery costs (LowREB, HighREB) and natural gas costs (LowNG, HighNG) from the 2021 ATB with alternative demand scenarios from the 2021 EIA AEO (LowDemand, HighDemand).

Figure 6a shows the distribution of national-average rates over 2020–2050 across the 11 ReEDS scenarios tested. The observed variability in retail rates across ReEDS scenarios is smaller than the variability across D/A/T projection assumptions: projected rates vary from 10.9 ¢/kWh (3.6% below the central case) for “LowREB,LowNG” to 11.7 ¢/kWh (4.1% above the central case) for “HighREB,HighNG”. Renewable energy generation in 2050 ranges from 30% of total generation in “HighREB,LowNG” to 80% of total generation in “LowREB,HighNG”.

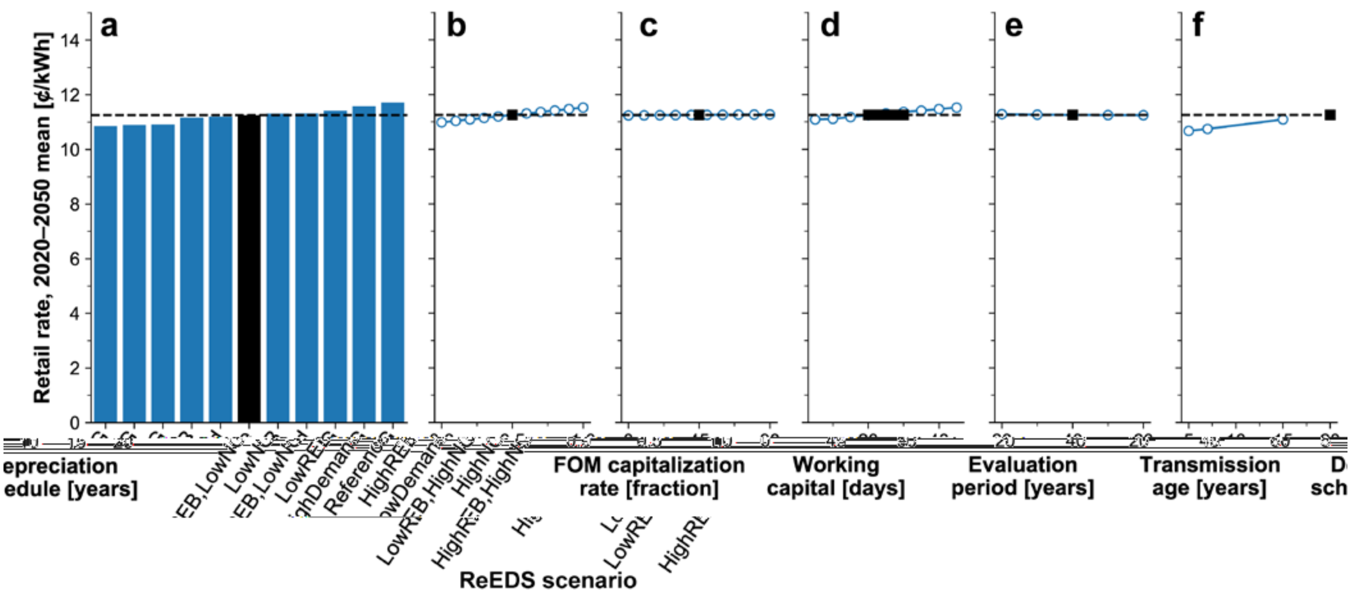


Figure 6. Sensitivity of the projected US-average retail rate to modeling assumptions.

The national-average retail rate over 2020–2050 is shown across variations in (**a**) the ReEDS scenario assumed, with scenarios assembled from the NREL 2021 Standard Scenarios report (Cole *et al.*, 2021); (**b**) FOM capitalization rate; (**c**) working capital days; (**d**) financial evaluation period; (**e**) assumed maximum age of the transmission fleet; and (**f**) the straight-line depreciation schedule used for generation assets. Values for default assumptions are indicated by black dashed lines, bars, and markers. State bias correction factors are used in all cases.

The impact of varying the individual accounting assumptions listed in Table 1 (apart from the financing assumptions discussed below) is relatively minor (Figure 6b-f); national average rates from 2020–2050 range from 10.7 ¢/kWh (5.2% below the central case) for the case with depreciation schedules for all technologies set to 5 years, to 11.5 ¢/kWh (2.4% above the central case) for the cases with financial evaluation periods for all technologies set to 45 years or FOM capitalization rate set to 100%. In general, increasing the assumed FOM capitalization rate, working capital days, financial evaluation period, or depreciation schedule increases the calculated retail rate. Increasing the length of time over which the existing transmission system is assumed to have been constructed decreases the calculated retail rate, but to a negligible extent (with a 0.04 ¢/kWh difference in rates between a maximum transmission age of 20 years and 60 years).

3.3.3 Financing assumptions

Financial assumptions (including the debt fraction, interest rate, equity return rate, and corporate tax rate, each of which contribute to the weighted average cost of capital or WACC) have a greater impact on retail rates than the scenario and accounting assumptions discussed in Figure 6. Figure 7 shows the response of average 2020–2050 retail rates to each of these financial parameters; in Figure 7a-d the debt fraction, interest rate, equity return rate, and tax rate are changed in isolation, while in Figure 7e-f the interest rate and equity return rate are varied together, with retail rates plotted as a function of the resulting WACC. Note that in practice, a change in interest rate (Figure 7b) or equity return rate (Figure 7c) would incentivize an IOU to shift its debt fraction in order to minimize its WACC; here these parameters are varied independently in order to illustrate their impact on model results.

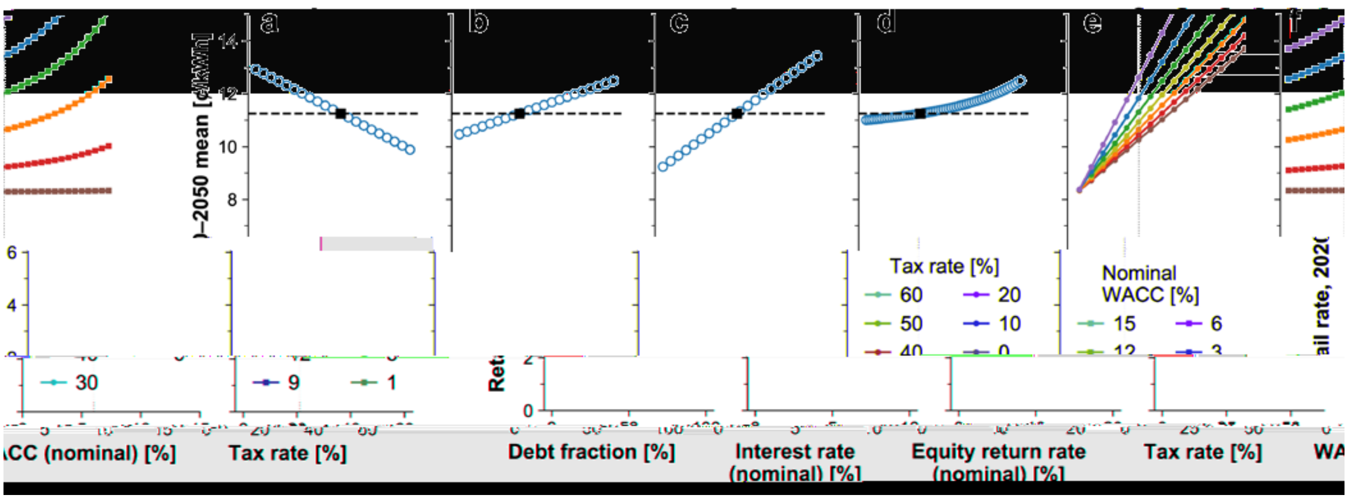


Figure 7. Sensitivity of the projected US-average retail rate to financial assumptions.

The national-average retail rate over 2020–2050 is shown across variations in (**a**) debt fraction, (**b**) nominal interest rate, (**c**) nominal equity return rate, (**d**) tax rate, (**e**) nominal WACC (default 6.0%) under constant tax rate, and (**f**) tax rate under constant nominal WACC. In **a-d** only the single *x*-axis parameter is changed, leaving other financial parameters at their default values. In **e-f** the equity return rate is set to twice the interest rate and both are varied linearly to generate the WACC values shown. Rates under default assumptions are indicated by black markers.

With other financial parameters held at the default values given in Table 1, a 1% absolute increase in the equity return rate or interest rate produces a 0.2 ¢/kWh increase in average 2020–2050 retail rate. Reducing the nominal WACC to 5.0% from its default value of 6.0% gives a retail rate of 10.6 ¢/kWh, lower than the lowest-rate ReEDS scenario in Figure 6; increasing the nominal WACC to 7.1% gives a retail rate of 11.8 ¢/kWh, higher than the highest-rate ReEDS scenario in Figure 6.

3.4 Comparison to alternative cost metrics

Figure 8 compares our calculated retail electricity rates (Figure 8c) with two other cost metrics typically used in ReEDS and other power system planning models: the marginal electricity cost (Figure 8a) and the annual system cost (Figure 8b). The calculation of these alternative metrics is described in Section 2.5.

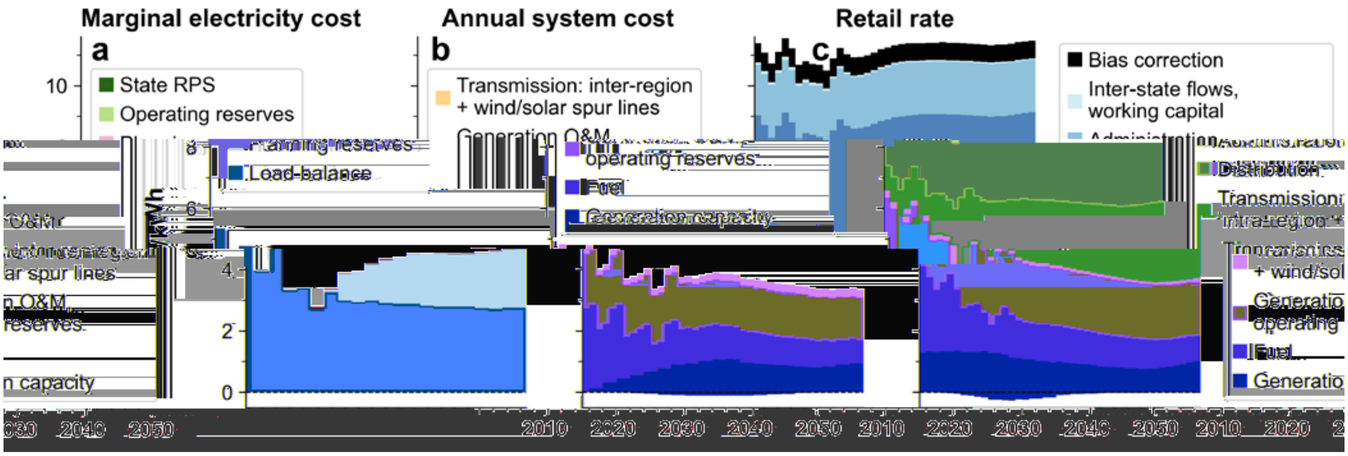


Figure 8. Comparison between alternative electricity cost metrics.

The calculation of the marginal electricity cost (**a**) and annual system cost (**b**) is described in Section 2.5; the retail rate (**c**) matches the rate shown in Figure 4. All rates shown here correspond to the "Mid" case from the 2021 Standard Scenarios report (Cole *et al.*, 2021), with accounting assumptions taken from Table 1.

The marginal electricity cost (Figure 8a) is "lumpier" than the other two metrics, as the full upfront cost of new capacity is recorded in the year it is built, and the metric is only resolved in directly modeled years (here every even year). New capacity built in a given year may add to any of the four components shown in Figure 8a, depending on which constraint the capacity was built to address. If there were no capacity (generation, transmission, or storage) built in a given year and there were no lost load or scarcity-pricing events in that year, the "load balance" component of the marginal electricity cost would correspond to the average wholesale electricity price.

The annual system cost (Figure 8b) is conceptually similar to the retail rate in that it records annualized bottom-up component costs, but it only includes components directly modeled by ReEDS. The annual system cost thus does not include the cost of existing capacity built before 2010 (hence the much smaller value of the "generation capacity" component in early years compared to Figure 8c) or the administration, distribution, intra-regional transmission, working capital, and bias-correction components discussed above. The annual system cost also uses technology-specific WACC values, producing costs representative of individual projects; the retail rate uses a single WACC, representative of IOU financing assumptions, for all components.

Comparing Figures 8a, b, and c, it is clear that the rate components unaccounted for in the marginal electricity cost and annual system cost metrics constitute a large fraction of total retail rates. This large fraction of relatively "fixed" ¢/kWh costs overshadows changes in scenario-dependent costs (Figure 6a), reducing the fractional (but not absolute) sensitivity of retail rates to changes in policy and technology assumptions. It is also notable that the transmission costs accounted for in ReEDS (here labeled as "Transmission: inter-region + wind/solar spur lines") are much smaller than the residual transmission costs derived from FERC data (here labeled as "Transmission: intra-region + O&M"). It is possible that the residual transmission costs are overestimated given our simplified projection of this component as a ¢/kWh rate adder; in either case, the projected cost of transmission additions warrants further analysis, particularly given the reported sensitivity of decarbonization costs to assumptions regarding transmission (MacDonald *et al.*, 2016; Brown and Botterud, 2021).

4 Conclusions

In summary, we have reported a bottom-up method for projecting the evolution of retail electricity rates in the US. Over the 10-year period from 2010–2019 for which our model overlaps with historically observed rates from EIA Form 861, our calculated nationwide rates are within –5% (–0.6 ¢/kWh) of historical values. Distribution, administration, transmission OPEX, and intra-region transmission CAPEX, which are not directly addressed in many capacity-expansion models, contribute 59% (6.6 ¢/kWh) to the total retail rate, on average, over 2020–2050.

Policymakers and other power-sector decision-makers should be aware of costs that are included in long-term planning models when basing decisions on model outputs. In this example, a raw system cost metric in ReEDS would greatly underestimate the cost of the electricity system paid by consumers. Similarly, a fractional difference in system generation & transmission cost between model scenarios would overestimate the fractional difference paid by consumers through retail rates. The ratemaking process also spreads cost recovery for generation and transmission capital assets over a multi-decade period, resulting in a smoother temporal profile for retail rates than for directly modeled system CAPEX and reducing "shocks" to customer bills. By including a method that captures a wider range of power sector costs, the value of a long-term planning model is increased.

The sensitivity analysis shows that financing assumptions (interest rate, equity return rate, and debt fraction) have a particularly large impact on calculated rates, followed by D/A/T projection assumptions, capacity-expansion model inputs (including generator capacity costs, fuel prices, and demand levels), and other accounting assumptions. As such, policies aimed at reducing financing costs for new generation and transmission capacity—along with efforts that reduce investment risks—would have a relatively strong influence on retail rates.

The rates reported here are under "no-new-policy" conditions, without any treatment of climate or health externalities or policy shifts; accounting for the social costs of fossil fuel combustion or implementing a rapid shift to an electrified and decarbonized economy would be expected to have a larger impact on system costs and retail rates than the small collection of alternative ReEDS scenarios examined here.

There are a number of areas for future research building on the approach described here. The relatively large bias errors for some states over 2010–2019 suggest that there is additional state-specific information that our accounting does not capture; state adjustments for labor rates, fuel costs, state/local policies, and financing costs for non-IOU entities could reduce the magnitude of the state bias-correction factor required. The impact of increasing DER penetration on distribution rates should be considered in future work, along with translation of overall rate estimates into residential, commercial, and industrial tariffs. Additionally, this work can be expanded to consider different accounting mechanisms such as for independent power producers or for structures that incorporate performance-based ratemaking. Given the large changes currently underway on the US electricity system, credible projections of future retail rates provide an important tool for assessing the impacts of a changing policy and technology landscape on distributional equity and consumer costs.

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Appendix A.

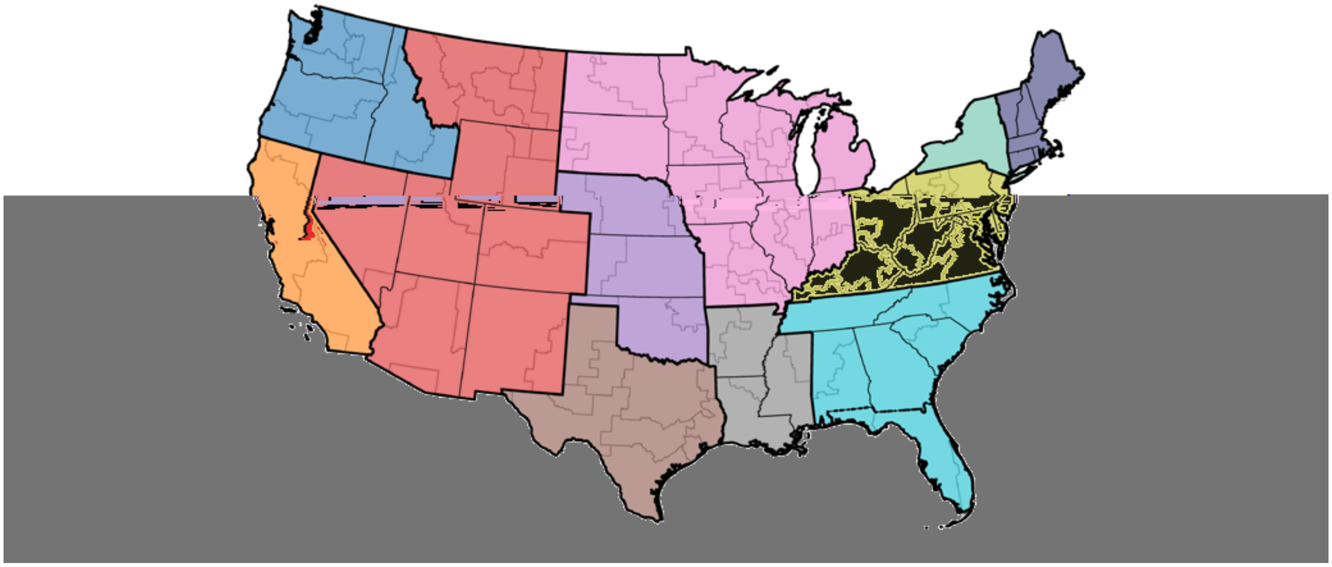

Figure A 1. Map of ReEDS BAs (light black lines), states (medium black lines), and regions (thick black lines with colored areas) used for retail rate calculations.

Regions are chosen to roughly correspond to ISO boundaries.