MARKET

Market and Retail-rate Knowhow for the Energy Transition

Research Needs and New Capabilities for Retail Electricity Rate Analysis

January 2025

Andrew Satchwell[1]
Elaine Hale[2]
Christina Simeone[2]
Samanvitha Murthy[1]

[1]Lawrence Berkeley National Laboratory
[2]National Renewable Energy Laboratory

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Prepared for the
Office of Energy Efficiency and Renewable Energy
U.S. Department of Energy

Principal Authors
Andrew Satchwell[1]
Elaine Hale[2]
Christina Simeone[2]
Samanvitha Murthy[1]

[1]Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

[2]National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401

January 2025

The work described in this study was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Acknowledgements

The work described in this study was conducted at Lawrence Berkeley National Laboratory and supported by the U.S. Department of Energy (DOE) Office of Energy Efficiency and Renewable Energy under Contract No. DE-AC02-05CH11231.

The authors would like to thank Paul Spitsen (DOE) for supporting this work and for his feedback on an earlier draft. For helpful feedback on an earlier draft of the report, we thank Stacy Miller (DOE), Robert Margolis (NREL), Juan Pablo Carvallo (LBNL), Thomas Bowen (NREL), Andrew Alberg (NREL), Adarsh Nagarajan (NREL), and Kate Anderson (NREL). Any remaining errors or omissions are our own.

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Acronyms and Abbreviations

DER	Distributed energy resource
DOE	Department of Energy
DPV	Distributed solar photovoltaic
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
LBNL	Lawrence Berkeley National Laboratory
NREL	National Renewable Energy Laboratory
VPP	Virtual power plant
VRE	Variable renewable energy

Executive Summary

Retail electricity rates are at the center of supply- and demand-side changes in future power systems, reflecting how system costs are recovered from customers and influencing distributed energy resource (DER) investment decisions, all with important implications for system reliability, resiliency, and energy affordability. Building on decades of research experience and analytical insights at Lawrence Berkeley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL), this report identifies key near-term analysis questions, enhancements to existing capabilities, and longer-term new analytical needs and capabilities to provide actionable insights for electricity system decision-makers, including state utility regulators, electric and gas utilities, ratepayer advocates, and DER solution providers. Table ES-1 summarizes the 5 topical areas and 20 research needs and new capabilities for retail electricity rate analysis that are detailed in the report.

Table ES-1. Retail electricity rate analysis topic areas, research needs, and new capabilities

Comprehensive accounting of utility system costs in rate estimates

- Estimating distribution system costs and impacts on rates
- Flexible translation of utility system cost and load data into rate models
- DERs as a substitute for conventional transmission and distribution system investments
- More granular cost of service studies with distributional impacts
- Cost benefit analysis of centralized grids v. decentralized grids

Forward-looking rate impacts that incorporate future changes in costs and loads

- Impact of extreme weather events and other natural disasters on rates
- Quantifying the electricity rate impacts of electrification
- Standard evaluation metrics of time-based and other rate options

Customer technology adoption decisions and response to retail rate designs

- Incorporating retail rate design scenarios in customer DER adoption projections
- Factoring customer reliability and resiliency into DER adoption decisions
- Enhanced DER adoption models and synthesized data and methods across sectors
- Database of utility programs and rate design outcomes

Gas and electric system cost interactions and customer energy bills

- Electrification impacts on the total energy bill and natural gas systems
- Natural gas system cost estimates under electrification
- Electricity-gas system co-evolution under different utility ownership structures

Impact of retail rates on industrial sector electrification, efficiency, and competitiveness

- Database of industrial customer electricity rates and energy purchase contracts
- Impacts of retail rate structures on industrial load flexibility
- Characterization of industrial customer energy and operating schedules
- Hourly matching and GHG emissions tracking
- Flexibility of decarbonized industrial processes

1. Introduction

The energy transition will profoundly change electricity system demand, customer consumption behavior and patterns, and variable renewable energy (VRE) supply. Power system loads and costs are changing due to the proliferation of large loads (e.g., data centers and advanced manufacturing facilities) that will create significant near-term growth in electricity load (EPRI, 2024; FERC, 2024). Additional and large increases in electricity demand over the next 5 to 10 years are expected from building and transportation sector decarbonization as customers convert building space and water heating from fossil fuel to heat pump technologies and adopt electric vehicles (EVs) (Langevin et al., 2023). Customer adoption and utilization of distributed energy resources (DERs) is also expected to increase as technology costs continue to decline, especially for distributed solar PV (DPV) paired with energy storage (Barbose et al., 2024). Dispatchable DERs in the form of virtual power plants (VPPs) will be particularly valuable resources to reduce the costs of balancing increasing load and VRE in future power systems (Hledik and Peters, 2023).

Retail electricity rates reflect the costs to generate and deliver electricity to consumers (Forrester et al., 2024) that are at the center of supply- and demand-side changes in future power systems. Importantly, retail electricity rate levels and rate designs reflect state-level policy objectives and will determine how future electricity supply will be split between centralized and distributed solutions.[1] Retail electricity rates, as well as natural gas rates, are also key determinants of energy affordability for households and businesses and can impact the competitiveness and growth of electricity-intensive industries. Therefore, there is an increased need to analyze, identify, and communicate the potential impacts of rate design on household and business decision-making, and the resulting costs and benefits to customers with and without DERs.

Figure 1 depicts the specific and important feedback loops between power system costs and loads, retail ratemaking, and DER[2] adoption and operations that should be represented in forward-looking retail rate analysis. For example, retail electricity rates (both price levels and design) are a key determinant for customers to make economically driven DER adoption decisions. The level of DER deployment, as well as the precise mix of DERs, may increase or decrease power system demand, which, in turn, may change generation, transmission, and distribution investment needs and costs. In turn, changes in power system costs and loads are incorporated into retail electricity prices. The precise impacts of DERs on retail electricity prices depends largely on their locational and temporal characteristics, as well as the balance between the cost impacts of future load growth and how costs of future and prior power system investments are spread across a broader base of retail electricity sales (Forrester et al., 2024; Satchwell et al., 2023). Capturing these feedback loops is critical to understanding how retail electricity rates influence system costs and DER adoption

[1] See Cawley and Kennard (2018) for an explanation of how retail electricity rates are determined, including process and inputs. See https://www.brattle.com/deliberate-design/ for consideration of state-level policy objectives in retail rate design.

[2] In this report, DER refers to all demand-side technologies that impact the amount or timing of electricity consumption, including behind-the-meter distributed generation (DG), behind-the-meter energy storage, energy efficiency, demand flexibility, and end-use electrification.

decisions, all with attendant implications for system reliability, resiliency, and energy affordability.

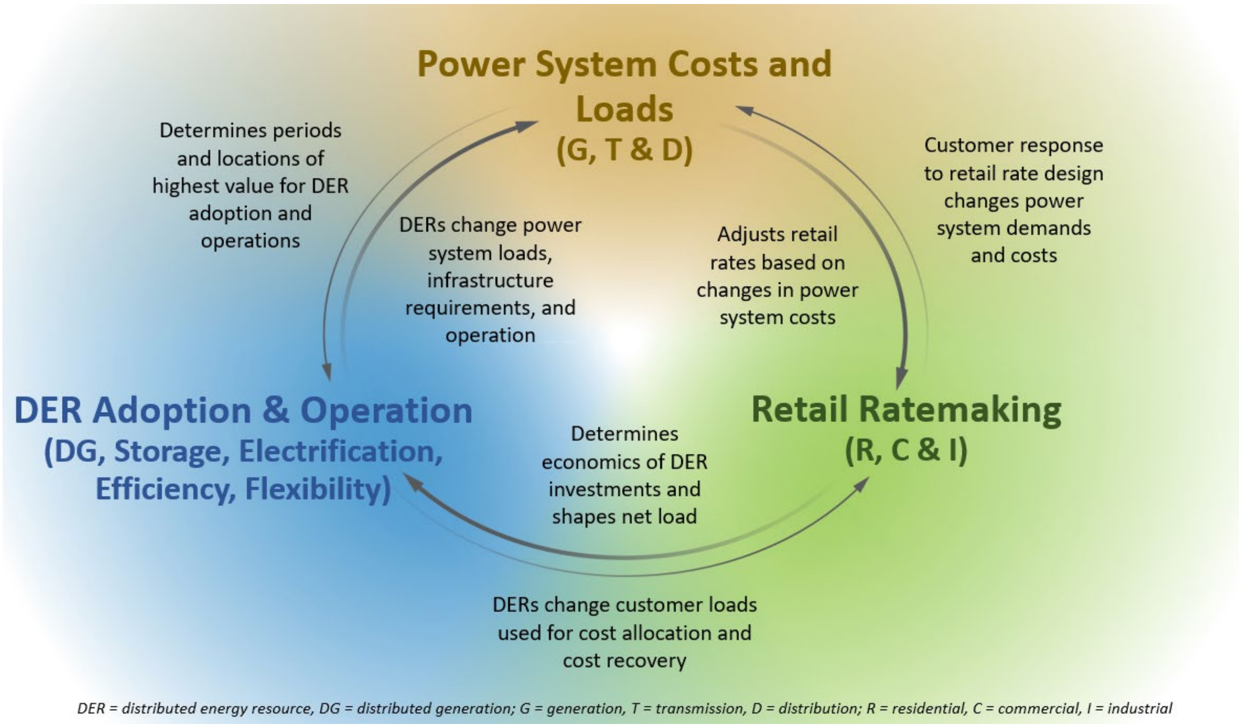

Figure 1. Feedback Loops between Retail Ratemaking, DER Adoption & Operation, and Power System Costs & Loads

Building on decades of research experience and analytical insights at Lawrence Berkeley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL), the report identifies key analysis questions, enhancements to existing capabilities, and new analytical needs and capabilities to provide actionable insights for electricity system decision-makers, including state utility regulators, electric and gas utilities, ratepayer advocates, and DER solution providers. Ratemaking processes to date mostly rely on historical cost and load information calculated for customer class averages and are often separate from distribution and bulk power planning processes. The report focuses primarily on analysis and capabilities that can inform public processes, explicitly include or consider retail rates, and are forward-looking to explore energy system changes.

The remainder of the report is organized as follows: Section 2 qualitatively evaluates current capabilities; Section 3 identifies analysis and capability needs; and Section 4 concludes with suggestions for near-term efforts to take action on the new analysis and capabilities.

2. Current Retail Electricity Rate Analysis Capabilities

We performed a comprehensive review of retail electricity rate analysis at LBNL and NREL, including models, datasets, tools, and other capabilities[3] that met three criteria:

1) Directly used in an analysis that included retail rates.
2) Publicly available and vetted via peer-reviewed publications and/or stakeholder review processes.
3) Forward-looking and can be used to explore energy system changes.

We reviewed 31 models, tools, datasets, and other capabilities and summarized the resolution of key inputs and outputs, primary methodologies (e.g., simulation, physics-based, empirical, accounting, optimization), representation of key feedback loops (depicted in Figure 1), comprehensiveness of metrics, scalability and linkages with other models in a cost-effective workflow, and dissemination of analysis, results, and insights. Because the review was limited to LBNL and NREL, it is not comprehensive of relevant capabilities at other public and private research institutions (e.g., Electric Power Research Institute, Rocky Mountain Institute, GridX, The Brattle Group). Nonetheless, we believe the breadth of review was sufficient to produce the list of analysis and capabilities needs in Section 3 that is broadly indicative of industry needs such that subsets of the entire list can be helpful to a wide range of stakeholders.

Table A-1 in the Appendix summarizes the analysis capabilities, inclusive of models, methodologies, and tools that explicitly consider retail rates. Importantly, we found a limited number of analyses and capabilities directly modeling or exploring the full range of interactions between DER operations and adoption, power system costs and loads, and retail ratemaking depicted in Figure 1. For example, NREL's Regional Energy Deployment System (ReEDS)[4] calculated changes in revenue requirements and retail electricity rates due to generation and transmission capacity expansion that were then used in the Distributed Generation Market Demand (dGen)[5] model to adjust DPV capacity adoption to examine feedback effects between power system capacity expansion, including utility-scale PV capacity, and DPV adoption (Gagnon 2017). Darghouth (2016) quantified the change in DPV adoption under different retail electricity rate designs by capturing feedback effects from increased fixed cost recovery and changes in the timing of peak-period electricity prices. LBNL's Financial Impacts of DERs (FINDER) model[6] quantifies changes in utility costs and revenues with the addition of DERs and includes capacity expansion and dispatch simulation and optimization to determine least-cost generation capacity and energy costs in response to DER load impacts. Finally, NREL's Holistic Electricity Model (HEM)[7] integrates consumer, utility, power producer, and regulator perspectives to explore feedbacks between DER adoption, power system investment, and rate design decisions.

[3] Capabilities are inclusive of standalone models, tools, datasets, and analytical capabilities, methods, and practice. Capabilities could also include standards or standards development for tool interoperability, dataset compilation, or industry practice.
[4] A model overview and publications are available at: https://www.nrel.gov/analysis/reeds/
[5] A model overview and publications are available at: https://www.nrel.gov/analysis/dgen/
[6] A model overview and publications are available at: https://emp.lbl.gov/projects/finder-model
[7] A model overview and publications are available at: https://www.nrel.gov/analysis/hem.html

A larger number of tools compute rates from exogenous inputs. These tools are often used on their own or at the end of a larger analysis to determine impacts on retail rates and create actionable insights and address stakeholder needs and information requirements. First, several tools and analyses (e.g., FINDER, SUPRA[8], and CPUC Bill Calculator Tool) have been used to support decision-making via technical assistance and applied to specific policy questions and utility locations as a result. Tool enhancements have also been driven by technical assistance needs. Second, several tools and analyses have supported stakeholder analysis, particularly for utilities (e.g., LA100-Equity Strategies project and the Consumer Affordability, Incentive, and Rates Optimization (CAIRO) model[9]). Third, tools and capabilities are frequently used in research projects that develop novel methodologies (e.g., Bill Alignment Test,[10] HEM) and produce results (e.g., via peer reviewed journal articles and technical reports) that advance stakeholder understanding and analysis.

There are also tools that examine the impact of rates or grid needs on DER adoption decisions and/or operations. Several of the tools focus on DER adoption (e.g., dGen, REopt[11]) or operations (e.g., foresee,[12] OCHRE[13]) and primarily interact with rates as exogenous inputs. Even so, these tools are sometimes used in iterative or co-simulation with power sector or rates models to perform integrated analysis. For example, dGen was used iteratively with ReEDS in Gagnon (2017), and OCHRE has been co-simulated with power sector models like OpenDSS and Sienna.[14] The two other tools in this category, DR-Path[15] and dsgrid-flex,[16] examine demand flexibility in the context of power systems, sometimes including responses to retail rates. DR-Path estimates the demand response shed and shift resource based on an exogenous description of grid needs, while dsgrid-flex produces battery-like flexibility models that can be dispatched against prices or aggregated for input into bulk power planning models.

Table A-2 in the Appendix summarizes the datasets that serve as inputs to the retail electricity rate analysis conducted at LBNL and NREL. The datasets explored were generally categorized as relating directly to retail rate data (n=1) or indirectly influencing rates through power system costs and loads (n=4), DER adoption and operation (n=13), or a combination of these data (n=1). Analysis of these datasets found there was strong coverage of bulk system resources and evolution, building and transportation loads, distributed renewable energy generation, and energy efficiency programs. There was limited coverage of demand flexibility and only emerging coverage of distribution system costs. There was only one database of utility rates, though this resource was quite comprehensive.

[8] A model overview and publications are available at: https://emp.lbl.gov/projects/supra-tool
[9] See Bowen et al. (2023).
[10] See Simeone et al. (2023).
[11] A model overview and publications are available at: https://reopt.nrel.gov/tool
[12] A model overview and publications are available at: https://www.nrel.gov/buildings/foresee.html
[13] A model overview and publications are available at: https://www.nrel.gov/grid/ochre.html
[14] A model overview and publications are available at: https://www.nrel.gov/analysis/sienna.html
[15] A model overview and publications are available at: https://buildings.lbl.gov/potential-studies
[16] A model overview and publications are available at: https://www.nrel.gov/analysis/dsgrid.html

3. Analysis and Capabilities Needs

Based on the review of current models, tools, datasets, and analyses described in Section 2, we identify potential needs to understand and effectively communicate forward-looking changes in retail electricity rate levels and rate designs, interactions with demand- and supply-side decisions, and implications for ratemaking to decision-makers. The analysis and capability needs are organized into five topical areas: comprehensive accounting of utility system costs in rate estimates; forward-looking rate impacts that incorporate future changes in costs and loads; customer technology adoption decisions and response to retail rate designs; gas and electric system cost interactions and customer energy bills; and impact of retail rates on industrial sector electrification, efficiency, and competitiveness.

For each topical area we describe:

- Why is this topic important to the energy transition? (e.g., How does it relate to changes in power system demand and/or supply? What are the implications for the energy transition if decision-makers don't have this information?)
- What is the capability and analytical need? (e.g., What data and credible assumptions are missing? What important variables or relationships are not represented? What scenarios need to be considered and explored?)

Comprehensive accounting of utility system costs in rate estimates

The energy transition will require significant investments in the power system from bulk power and distributed generation to regional transmission and local electricity delivery. Decision-makers need a comprehensive accounting of the change in system costs (and, in some cases, the corresponding benefits) of increasing amounts of electricity consumption, VRE, and customer investments in DERs. Models, tools, and datasets quantifying electric utility costs have, to date, aligned with power system physical and operational characteristics (i.e., bulk power generation and transmission and lower voltage distribution systems are studied separately). Retail electricity rate and customer bill impacts of the energy transition will ultimately flow from changes across entire utility systems and from all cost categories inclusive generation, transmission, and distribution costs, as well as program costs, administrative costs, financing costs, and other miscellaneous costs. Ideally, this full accounting should also enable assessment of the tradeoffs of strategies that minimize generation and transmission costs vs. minimize distribution costs (e.g., EV charging to avoid higher annual system load vs. relieving feeder-level constraints).

Estimating Distribution System Costs and Impacts on Rates

There is a need to broaden and deepen the understanding of how general (and not necessarily territory-specific) distribution system upgrades and maintenance costs scale with electrification, DER adoption/capacity increases, and control/aggregation approaches. From that understanding, different technical approaches available to reduce network upgrade costs should be explored along with the rate impacts of different upgrade cost allocation strategies. These research and data efforts will fill a gap in understanding how distribution system upgrade costs scale with DERs and change with upgrade solutions, hence improving revenue requirement estimates and rate analysis.

Flexible translation of utility system cost and load data into rate models

Currently, there are limited capabilities to aggregate all required data and utility costs (generation, transmission, distribution, and other) into a single coherent input data set and revenue requirement across a range of tools. This capability would define interfaces for different tool categories (e.g., bulk system capacity expansion, distribution system capacity expansion, rate calculators) that, once supported by a tool, would enable smooth interoperability in terms of linking various system data and costs with the calculation of rates. This would improve the quality, consistency (across tools), and efficiency of rate analysis.

DERs as a substitute for conventional transmission and distribution system investments

Expanding the transmission network to integrate renewable energy is a critical pathway to enable the energy transition, but concerns have arisen about the potential for higher electricity costs. A nationwide analysis of transmission charges could help compare these costs to generation and distribution components of electricity bills. Additional analysis would explore cost allocation mechanisms and assess how DERs could reduce transmission charges in concept and in practice. Likewise, as distribution system costs rise to modernize grids, utilities are considering DERs (e.g., residential batteries) as alternatives to traditional upgrades. New tools should be developed for utilities and others to assess this approach (i.e., to evaluate its effects on distribution system reliability, costs, and rates).

More granular cost of service studies with distributional impacts

The historical practices for developing cost-of-service studies functionalize costs (often historical utility costs) by generation, transmission, and distribution. They also allocate costs to broad customer classes based on monthly sales, monthly and annual demand, and annual customer counts, but do not typically consider heterogeneity within customer classes, especially at the hourly load level. Analysis of unbundled rates by grid service (e.g., energy, capacity, distribution deferral) can create greater value for DERs and inform rate design to more appropriately compensate customers for providing different grid services. Analysis can inform regulators and utilities about practices for considering equity in cost-of-service studies or the use of AMI data for distributional analysis.

Cost benefit analysis of centralized grids v. decentralized grids

Retail electricity pricing is historically based on the premise of economies of scale, whereby the costs of centralized generation and transmission are spread over a large amount of sales. Today, however, there are several commercially available technologies for more local and distributed generation and distribution of electricity. There is a need to understand what the implications on retail electricity prices would be under different physical, operating, and planning models for highly centralized grids vs. decentralized grids achieved through increased DER deployment inclusive of implications for resource adequacy, reliability, and resilience.

Forward-looking rate impacts that incorporate future changes in costs and loads

Supply- and demand-side changes in the power sector are occurring over the long term and will likely proceed at different paces among states based on differences in goals and resources. Accounting for and signaling the costs, benefits, and value of DERs within the long-term energy transition will be necessary to encourage economically efficient technology development. Quantifying potential retail electricity rate impacts in a forward-looking manner is especially important given the expected rapid pace of change over the next two decades, and the need to signal critical investments in demand-side resources as power systems transition from low to mid to high shares of VRE, and from low to mid and high levels of heating, transportation, and industrial electrification. Current models and tools have been able to demonstrate some of the relevant feedback loops and implications thereof, but not broadly or deeply enough to comprehensively evaluate how retail electricity rates could evolve over time. The evolution of retail electricity rates in a high electrification future should consider changes in customer total energy bills inclusive electricity and other fuel costs (e.g., natural gas, gasoline, propane, fuel oil).

Impact of extreme weather events and other natural disasters on rates

Historically, some utilities have accrued large costs to rebuild and recover following extreme weather events and natural disasters. Because the frequency of extreme weather events is increasing, an increasing number of utilities are expected to face such large, unexpected costs in the future. There is thus a need to better understand the magnitude of power system costs attributed to extreme weather events and natural disasters in the past; how those costs were allocated to revenue requirements, taxpayers, and insurance companies; and the resulting impacts on historical rates. The understanding gained through such an activity could then be used to describe possible approaches for managing these costs in the future.

Quantifying the electricity rate impacts of electrification

The electrification of space and water heating in buildings and electrification of transportation will have a significant impact on electricity demand, changing both the magnitude and timing of demand within and across days and seasons. These changes will require infrastructure investments in the power system that put upward pressure on electricity rates. At the same time, electric load growth will spread these costs over more electricity sales, putting downward pressure on rates. The degree to which increased sales mitigate the impact of infrastructure investments on customer electricity bills has implications for energy affordability, DER adoption, and the economics of electrification. Analysis is needed to capture feedback between increasing building-level electricity demand, utility cost impacts, and how those costs are allocated to and recovered from retail rates. Mitigation approaches and measures, like demand flexibility and alternative retail electricity rate designs should also be explored.

Standard evaluation metrics of time-based and other rate designs

State utility regulators consider policy (e.g., Bonbright principles) in approving and providing guidance on retail electricity rate design, in addition to ensuring rates collect just and reasonable revenues. Analysis and modeling capabilities largely focus on cost levels and should be enhanced to consider and evaluate other factors in retail electricity rate design (e.g., alignment of time-of-use rate peak periods and VRE production, customer response to time-based rates and the associated long-run cost impacts). New capabilities may include post-processing to evaluate alignment of rates with a range of criteria that result from or are provided as inputs into modeling efforts. Analysis may compare rate design criteria to outcome-based evaluation metrics (e.g., increased DER adoption, affordability by customer class).

Customer technology adoption decisions and response to retail rate designs

Widespread customer investments in DERs can potentially deliver benefits to households, businesses, and communities by enabling greater electricity bill management and mitigating the costs of a high demand future (Langevin et al., 2023). Whether benefits accrue at sufficient scale are dependent on customer technology adoption decisions, which are based on a range of monetary and non-monetary factors (which themselves are influenced by different utility regulatory and business models). In addition, decision-makers need support in understanding the impact and implications of changes to retail electricity rate designs and whether they will accelerate or impair the achievement of state energy goals, as well as for comparing electric to non-electric (e.g., natural gas) technologies. Utilities and regulators lack foundational datasets and information to make informed assumptions about what factors matter most for different groups of customers, as well as how customers respond to alternative retail electricity rate designs and DER program incentives, especially when customers are considering a wide range of potential investments. Improved datasets would enable more precise quantification of DER participation in providing grid services (e.g., by incorporating customer price elasticity assumptions into power sector cost analysis, or by improving likely DER adopter models through greater empiricism) and influence DER potential and adoption modeling via revised total costs and benefits of ownership.

Incorporating retail rate design scenarios in customer DER adoption projections

Current tools for evaluating customer DER adoption decisions are premised on simplified assumptions about future retail rates (e.g., flat average rate designs, cost escalation typically consistent with historical growth). However, changes in retail electricity rate designs and price levels are likely to have significant impacts on the customer economics of DER investments. Forward-looking analysis should reflect the broader set of actual retail electricity rate designs for DERs, including net metering alternatives and time-of-use rates, as well as future projections of utility rate growth.

Factoring customer reliability and resiliency into DER adoption decisions

Grid reliability concerns may motivate customer adoption of DERs that can serve as a backup power source. For example, utilities in the West are using targeted outages to mitigate wildfire risks and customers are experiencing greater frequency of service interruptions. This is an emerging trend and much of the existing analytical work on DERs for customer reliability and resiliency relies on simplified assumptions about customer behavior and technology performance. Current analysis and capabilities also do not always factor reliability into DER adoption decisions, especially how they vary with recent experience of short- or long-term outages and other factors, and how the strength of the reliability motivator might change as technology performance during outages improves and changes over time.

Enhanced DER adoption models and synthesized data and methods across sectors

Analysis and modeling of customer adoption decisions has developed within technology silos, and with highly fractured assumptions and varying levels of maturity across different sectors. This results in inconsistent cross-sectoral scenarios describing future technology adoption and energy use that would otherwise more precisely represent the interrelatedness and complexity of the energy transition. New modeling capabilities should include commercial and industrial sector DER adoption decisions (in addition to the residential sector) and compare key adoption factors across sectors and technologies.

Database of utility programs and rate design outcomes

The review of retail electricity rate analysis, capabilities, and datasets (see Section 2) did not identify a publicly available database on customer enrollment in and response to retail electricity rate designs and incentive programs. Such a database could provide information on program costs, incentive levels, technology adoption, opt-in and opt-out rates, changes as programs/rates migrate from being pilots to being full-fledged programs/rates, measurement and verification results, and utility cost and benefit estimates. Much of this data is likely embedded in state regulatory filings across multiple dockets; as such, machine learning approaches might be productively applied.

Gas and electric system cost interactions and customer energy bills

A key strategy to achieve state goals for emissions reductions is to convert fossil-fuel building end-uses (e.g., natural gas furnaces, water heaters, cooking ranges) and transportation modes (e.g., passenger, transit, vocational, and freight vehicles) to electricity, with additional consumer benefits of increased comfort, health, and safety. Power system modeling and analysis have emphasized the electricity generation, transmission, and distribution grids with limited capability to identify and quantify potential changes in natural gas system costs and prices. Improving the ability to estimate these potential changes in system costs (e.g., through total energy costs) is critical in energy transition scenarios, especially in a high demand future where electricity system costs are projected to increase dramatically. There are related insights for customer energy affordability and electrification under scenarios in which natural gas system legacy fixed costs are spread over declining natural gas sales, thereby increasing volumetric delivered natural gas costs and potentially contributing to widespread natural gas system defection.

Electrification impacts on the total energy bill and natural gas systems

Increased end-use electrification has the potential to increase electricity bills, reduce bills for other fuel types (e.g., natural gas and gasoline), and increase per customer natural gas delivery costs by reducing the number of customers over which fixed costs are recovered. Enhancements to existing retail electricity rate analysis and capabilities are, therefore, necessary and should include avoided fossil fuel fixed and variable cost information, and the changes to natural gas regulatory frameworks and ratemaking approaches being considered by states and municipalities in the context of declining natural gas consumption. Given the heterogeneity in customer building characteristics and energy consumption, total energy bill impacts should be quantified across the entire distribution of customers to explore changes in energy affordability.

Natural gas system cost estimates under electrification

There is currently limited capability to determine how natural gas costs associated with supplying end customers are divided between fixed and variable costs. There is a need to make such estimates, perhaps from existing studies and planning documents from natural gas suppliers. Depending on the resolution of the data, filling this need could provide better basic estimates for how fixed costs are spread over fewer sales under electrification scenarios or could go further to provide guidance based on natural gas infrastructure characteristics (e.g., location, age).

Electricity-gas system co-evolution under different utility ownership structures

Utilities typically provide either electricity or natural gas services, or both, and, as such, are expected to face different incentives under high electrification futures with important implications for financial risks and stability. New analysis and capabilities are needed to explore different financial and operational outcomes for different utility ownership types and business models, and identify regulatory and market design options that incentivize electrification and minimize cost increases for certain customers.

Impact of retail rates on industrial sector electrification, efficiency, and competitiveness

The industrial sector, including data centers and advanced manufacturing, will drive the supply- and demand-side requirements of the future power system given their significant facility-level power demands and rapid growth. Existing industrial customer retail electricity rates that emphasize demand charges could impede progress towards electrification of industrial processes, especially among energy-intensive sub-sectors like steel, cement, and ammonia or processes with highly variable operations and thus lower load factors like water pumping and food processing. Conversely, DERs and demand flexibility strategies could help mitigate electricity bill impacts by reducing overall peak demand, shifting consumption to off-peak hours, and directly responding to grid signals. Affordable electrification, in part via fuel switching, could also support firm competitiveness by keeping production costs low. However, electrification is only affordable if the cost of any necessary service upgrades and rates are sufficiently low. Based on the cost causation principle, upgrade costs are only passed on to direct beneficiaries and may result in unexpectedly high costs, especially for existing small customers. Achieving low rates requires continuous management and improvement of power system investment and operation costs, as well as ensuring that any DER excess generation and demand-side program costs passed on to the customer class are cost-effective for non-participants. Foundational datasets of current industrial customer retail electricity rate structures, as well as credible industrial customer load shapes that reflect important heterogeneity in facility characteristics and manufacturing processes, are critical for a broader and deeper understanding of these impacts. Such foundational data combined with empirical data on industrial customer response to alternative retail electricity rates, especially highly dynamic pricing or direct bidding into wholesale markets, could provide informed analysis of the efficacy of DERs and demand flexibility strategies. Finally, analysis of industrial customer energy costs and electricity bills can inform assessments of sectoral growth and competitiveness.

Database of industrial customer electricity rates and energy purchase contracts

Medium and large industrial customers are unique in that they can purchase electricity in a myriad of ways. For example, some industrial customers are subscribed to utility electricity tariffs tied to overall demand levels, whereas other industrial customers negotiate power purchase agreements with independent power producers or purchase electricity directly through wholesale markets. Importantly, the ways in which rate structures incentivize adoption of electrification technologies and demand flexibility are likely to influence the pace and magnitude of industrial sector demand and emissions. New datasets of enrollment and rate design by industrial customer characteristics (e.g., manufacturing process, facility size, technology selections including DERs) would enable accurate assessments of potential electricity bill impacts from electrification, incentives for load flexibility, as well as present an opportunity to develop novel rate structures that could simultaneously encourage renewables integration, energy affordability, and grid reliability. Furthermore, this could also be extended to account for other fuel purchases such as natural gas, propane, and coal, which will allow for a broad understanding of existing energy requirements and expenditures and inform feasibility of electrification and the growth in demand.

Impacts of retail rate structures on industrial load flexibility

As some industrial end-uses electrify and the share of VRE increases, increased quantities of economic load shedding and shifting over short and diurnal timescales can help mitigate the costs of power system expansion. However, many industrial facilities on retail rates manage their electricity use and on-site DERs in part to minimize monthly or coincident peak demand charges. New analysis is needed to explore the impact of managing hourly (and sub-hourly) industrial energy use to minimize bills across various existing and novel retail rate structures, and across industrial subsectors and geographies, on system- and customer-level costs and emissions. Examining the impacts of existing rate structures would describe the extent to which current rate structures are or are not a barrier to affordable electrification, and examining novel rate structures could point toward retail rate designs that better align customer incentives with system-level goals.

Characterization of industrial customer energy and operating schedules

Electrification of industrial processes, in addition to new demand from data centers and advanced manufacturing, will lead to significant increase in total system electricity demand and will likely change the magnitude and timing of system-level peak demand. There is a lack of publicly available data to establish electricity consumption metrics for different industrial processes, including electricity and non-electricity load profiles with sufficient temporal and spatial resolution for power system and customer bill impacts modeling. Such datasets could supplement tools used by programs, like Industrial Assessment Centers,[17] to optimize overall energy consumption for industrial facilities and reduce costs.

Hourly matching and GHG emissions tracking

Industrial electrification and data center applications (e.g., artificial intelligence and machine learning) are energy-intensive and are expected to result in significant increases in electricity demand in the near term. Many companies are motivated by corporate emissions reduction goals or are subject to requirements in other countries to inventory and quantify product emissions. Therefore, for some firms demonstrating emissions reductions associated with electricity use could be as important as minimizing energy costs. New analysis should explore the interaction between industrial sector customer strategies to procure electricity (e.g., via power purchase agreements, wholesale market, or self-generation) and the resulting cost and emissions impacts on the firm, as well as the power system. For example, the electricity rate impacts of various clean power procurement strategies, which are typically subject to some combination of incrementality, deliverability, and time-matching requirements,[18] could be explored.

Flexibility of decarbonized industrial processes

Electrification of industrial processes would have significant impacts on power systems in terms of demand growth, system-planning, availability and procurement of resources. Specifically, the need and availability of load flexibility resources can also be expected to change considerably. Hence, it would be necessary to revise current sub-sector- and process-specific flexibility characterizations and update to account for changes expected to be induced by industrial decarbonization in the existing as well as new processes while accounting for the uncertainties in the resource potential estimates. This analysis would characterize the changes in load and flexibility metrics based on facility size, energy transition strategy, and DER deployment.

[17] The U.S. Department of Energy supports university-based Industrial Assessment Centers that provide energy-related technical assistance to small and medium-sized U.S. manufacturers. More information is available at https://iac.university/

[18] The principles of incrementality, deliverability, and time-matching are incorporated into the U.S. Department of Treasury's final rules for the clean hydrogen production tax credit. More information is available at https://home.treasury.gov/news/press-releases/jy2768

4. Conclusions

The report frames critical feedback loops between power system costs and loads, retail ratemaking, and DER adoption and operations. Based on the framing and a review of LBNL and NREL analysis, tools, datasets, and other capabilities, we identified 5 topical areas and 20 research needs and new capabilities. These questions frame beneficial enhancements to existing capabilities, and development of new analytical needs and capabilities to provide actionable insights for electricity system decision-makers. Some of the questions and issues the analysis and capabilities could inform include:

- What are the implications of buildings, transportation, and industrial electrification on power generation, transmission, and distribution system costs?
- What are the most reliable and cost-effective future grid investment strategies given state-level policy drivers, utility operational and financial characteristics, and location-specific demands?
- What is the role and effectiveness of rate designs in driving customer adoption of affordable and beneficial energy technologies?
- What are the appropriate retail rate designs to align load schedules and DER operations with economically efficient power system investments and dispatch?

The pace and scale of future changes in the power system likely necessitate progress on all the analysis and capabilities needs in this report. However, there are some near-term efforts that are necessary to fill gaps or develop capabilities that enable follow-on analysis. For example:

- Publicly available datasets for customer enrollment in and response to retail electricity rate designs, as well as for industrial customer load profiles and tariff details, are necessary to perform insightful analysis on customer bills and power system costs and loads.
- Capabilities to model natural gas systems and estimate changes in natural gas prices as consumption declines are necessary to more comprehensively explore total customer energy bills under electrification and the potential value of DERs to mitigate both electricity and natural gas system costs, especially in the distribution systems.
- Capabilities that can represent the patchwork of state practices for retail electricity ratemaking and different utility operational and financial characteristics are important to understanding impacts of the energy transition at the state- and local-levels.

The analytical needs and capabilities in this study could be developed either within the national labs or among industry stakeholders more broadly. Importantly, the analysis and capabilities should be made publicly available to increase the benefits associated with strategic capability development and help further advance scientific research and practical understanding of a wide range of retail electricity rate topics.

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Appendix. Review of LBNL and NREL Models, Tools, and Datasets for Retail Electricity Rate Analysis

Table A-1. Review of Models and Tools that Perform Retail Electricity Rate and Related Analysis

Feedback Loop Representation	Existing Capability or Analysis	Capability Description
Retail Ratemaking (primary); Power System Costs & Loads (secondary)	FINancial Analysis of Distributed Energy Resources (FINDER) Model (LBNL). Available at: https://emp.lbl.gov/projects/finder-model	Performs pro-forma financial and accounting, capacity expansion and dispatch simulation and optimization (*method*) from Utility characterization (annual revenue requirement, financial characteristics), Ratemaking assumptions (rate case filing frequency, regulatory lag, test year treatment, cost of service study, rate design), DER characterization (annual penetration, ratepayer-funded costs), and Capacity expansion and dispatch assumptions (*inputs*) to produce customer class retail rates and bills, utility after-tax achieved return-on-equity and earnings (*outputs*).
Retail Ratemaking (primary); Power System Costs & Loads (secondary)	Impacts of Load Response to Dynamic Tariffs in California (LBNL). Available at: https://eta-publications.lbl.gov/publications/california-demand-response-0	Simulates class-neutral dynamic rates estimated based on class-average load shape, and performs time-series analysis (for load response), regression (for wholesale price prediction), and accounting (for customer bill impacts) (*methods*) from hourly customer load shape, class-neutral rates, sector-specific elasticity values (*inputs*) to produce load response to dynamic rates, customer bill impacts, system-level impacts (*outputs*).
Retail Ratemaking (primary); DER Adoption & Operation (secondary)	California Public Utilities Commission (CPUC) Bill Calculator Tool (LBNL)	Uses accounting methodology to calculate electricity bills (*method*) from hourly system-level gross load, VRE generation, customer load, and subscription load shape. A subscription load shape is a pre-purchased load shape (based on historical consumption) for each customer class that is billed under an Other Applicable Tariff (OAT) (*inputs*) to produce annual customer bill impacts for different dynamic rate structures (*outputs*).

Feedback Loop Representation	Existing Capability or Analysis	Capability Description
Retail Ratemaking (primary); DER Adoption & Operation (secondary)	Customer Affordability, Incentive, and Rates Optimization (CAIRO) (NREL) Example paper using CAIRO located at: https://www.nrel.gov/docs/fy24osti/85952.pdf	Performs optimization and accounting (*methods*) from residential annual-hourly customer load, customer metadata (e.g., income, tenure, housing attributes), fixed tariff elements, adjustable tariff elements, utility revenue requirement, marginal system costs, DER shares and generation assumptions, and customer assistance strategies (*inputs*) to estimate customer-level (and sub-class breakdowns) of monthly and annual bills, evaluation metrics for affordability and equity (*outputs*).
Retail Ratemaking (primary); DER Adoption & Operation (secondary)	Bill Alignment Test Method (NREL, LBNL) Example paper using the BAT method located at: https://doi.org/10.1016/j.jup.2023.101539	Uses accounting (*methods*) from residential annual-hourly customer load, customer sub-class data (e.g., low income), tariff design parameters, residual allocation method(s), utility revenue requirement, marginal system costs, and DER penetration and output assumptions (*inputs*) to produce customer-level (and sub-class breakdowns) annual bills, bill alignment metrics on customer cross-subsidies, economic efficiency metric (deadweight loss), histogram graphics, results tables by key customer sub-classes (low income, DER owner, energy use quartiles) (*outputs*).
Retail Ratemaking (primary)	Standardized Utility Pro-forma Financial Analysis (SUPRA) (LBNL). Available at: https://emp.lbl.gov/projects/supra-tool	Pro forma financial model (*methods*) from Utility cost elements and their forecasted growth; Major planned capital expenditures; Retirement or catastrophic loss of grid-scale generation assets; Utility billing determinants and their forecasted growth; Ratemaking; Customer technology and utility programs; Catastrophic events (e.g., hurricanes) (*inputs*) to calculate utility revenue requirement, retail rates, collected revenue, and financial health metrics including cash position, debt service coverage, and days liquidity, as well as earnings and return-on-equity for investor-owned utilities (*outputs*).

Feedback Loop Representation	Existing Capability or Analysis	Capability Description
Power System Costs & Loads and DER Adoption & Operation (primary); Retail Ratemaking (secondary)	Holistic Electricity Model (HEM) (NREL). Available at: https://www.nrel.gov/analysis/hem.html	Computes an agent-based equilibrium (or non-converging simulation) (*method*) from existing bulk power assets and market structure, retail rate structure(s), existing DER assets and adoption models, existing and possible future contractual agreements (e.g., demand response/VPP, voluntary green power) (*inputs*) to produce power system costs, wholesale and retail electricity prices, bulk power and customer-sited investment and participation decisions, costs and surplus per market participant (*outputs*).
Power System Costs & Loads and DER Adoption & Operation (primary); Retail Ratemaking (secondary)	dsgrid-flex (NREL). Available at: https://www.nrel.gov/analysis/dsgrid.html	Performs accounting and other algebraic calculations, optimization, and simulation (*methods*) from device (e.g., vehicle, water heater, battery) descriptions sufficient to describe operational flexibility, information for linking to a bulk power system planning model (e.g., production cost or capacity expansion model) (*inputs*) to produce time-varying, battery-like flexibility models at the individual device (kW-scale) and aggregate (MW-scale) level; device-level dispatch outcomes for price-responsive dispatch mechanisms (*outputs*).
Power System Costs & Loads (primary); Retail Ratemaking (secondary)	Regional Energy Deployment System (ReEDS). Available at: https://www.nrel.gov/analysis/reeds/; ReEDS Retail Rate Module (NREL). See: https://www.nrel.gov/docs/fy22osti/78224.pdf	Least-cost optimization (*methods*) from current power system, future technology costs and performance, fuel prices, policies, etc. (*inputs*) to produce power system investments, retirements, and operations over the next several decades; power system costs, emissions, and transmission infrastructure; health damages; siting of renewable energy (*outputs*). Accounting (*methods*) from historical rate information by component (*inputs*) to produce retail rate components for generation and transmission, estimates for overall revenue requirements and total retail rates, which enable iteration with DER adoption models like dGen (*supplementary outputs*).

Feedback Loop Representation	Existing Capability or Analysis	Capability Description
DER Adoption & Operation (primary); Retail Ratemaking (secondary)	Distributed Generation Market Demand (dGen) Model (NREL). Available at: https://www.nrel.gov/analysis/dgen/	Performs agent-based accounting (*methods*) from agent definitions and metadata, individual customer load shapes, agent rooftop size and direction, PV generation profiles, DER costs, retail rates (*inputs*) to produce DER adoption per agent, statistical descriptions of adopters vs. non-adopters, aggregate DER generation profiles (*outputs*).
DER Adoption & Operation (primary); Retail Ratemaking (secondary)	REopt (NREL). Available at: https://reopt.nrel.gov/tool	Performs mixed-integer linear programming to minimize costs over an analysis horizon (*methods*) from location, electric/thermal loads (sub-hourly to annual), utility rate (custom or URDB), DER technologies to consider, site energy goals (cost savings, decarbonization, resilience) (*inputs*) to produce cost-optimal DER sizing and economic dispatch, renewable energy and emissions metrics, resilience metrics (probability of meeting critical loads for varying outage durations), cost of energy metrics (e.g., LCC, NPV, LCOE, proforma) (*outputs*).
DER Adoption & Operation (primary); Retail Ratemaking (secondary)	foresee (NREL). Available at: https://www.nrel.gov/buildings/foresee.html	Performs model predictive control (*methods*) from a residential building energy model, occupant preferences, occupant schedule (*inputs*) to produce DER controls and a flexible load envelope (*outputs*).
DER Adoption & Operation (primary); Power System Costs & Loads (secondary)	DR-Path (LBNL). Available at: https://buildings.lbl.gov/potential-studies	Calculates the maximum shed/shift demand response resource for a given price (*methods*) from hourly regional gross load; VRE generation for a given year; DR technologies and cost characterization data such as technology saturation values, shed/shift fractions; costs of purchase, installation and operation (*inputs*) to produce demand response supply curves for a given year, which can be used in system planning, and, in turn, rates (*outputs*).

Feedback Loop Representation	**Existing Capability or Analysis**	**Capability Description**
DER Adoption & Operation (primary); Power System Costs & Loads (secondary)	OCHRE (NREL). Available at: https://www.nrel.gov/grid/ochre.html	Performs agent-based time series simulation (*methods*) from building and DER parameters, occupant schedules, weather data, DER control methods (*inputs*) to produce building load profiles, DER power profiles, and occupant comfort estimates (*outputs*). Interacts with power system simulations through co-simulation (e.g., OpenDSS, Sienna) and responds to exogenous retail rates (e.g., URDB, Cambium) (*supplementary methods*).
Power System Costs & Loads (primary); DER Adoption & Operation (secondary)	Sienna (NREL). Available at: https://www.nrel.gov/analysis/sienna.html	Performs optimization (*methods*) from power system unit-level operating costs and parameters, e.g., generating units, lines, switches, fuel costs, heat rates, feasible operating regions, thermal limits (*inputs*) to produce hourly or sub-hourly data describing forward schedules and outcomes for generator dispatch, line flows, constraint violations, and costs (*outputs*). Designed for co-simulation with DER and other energy system models (*supplementary methods*).

Table A-2. Review of Datasets to Inform Retail Electricity Rate Analysis

Feedback Loop Representation	Existing Capability	Data Description	Link
DER Adoption & Operation	ResStock (NREL)	Residential load shapes by end-use and county	https://www.nrel.gov/buildings/resstock.html
DER Adoption & Operation	Scout (DOE, led by LBNL)	Savings shapes and operating cost savings of energy conservation measures	https://scout.energy.gov/
DER Adoption & Operation	ComStock (NREL)	Commercial load shapes by end-use and county	https://comstock.nrel.gov/
DER Adoption & Operation	Cost of Saving Energy (LBNL)	Program Administration costs of saving electricity via Energy Efficiency programs	https://emp.lbl.gov/projects/what-it-costs-save-energy
DER Adoption & Operation	EVI-Pro (NREL)	EV charging profiles and EVSE requirements	https://www.nrel.gov/transportation/evi-pro.html
DER Adoption & Operation	TEMPO (NREL)	EV charging profiles and flexibility envelopes	https://www.nrel.gov/transportation/tempo-model.html
DER Adoption & Operation	Tracking the Sun (LBNL)	State-specific cost parameters in the US for installing rooftop PV	https://emp.lbl.gov/tracking-the-sun
DER Adoption & Operation	DR-Path (LBNL)	Demand Response resource supply curves	https://buildings.lbl.gov/potential-studies
DER Adoption & Operation and Power System Costs & Loads	System Advisor Model (NREL)	Hourly generation profiles for weather-dependent technologies	https://sam.nrel.gov/
DER Adoption & Operation	REopt (NREL)	Site-level system sizing, costs and emissions	https://reopt.nrel.gov/tool
DER Adoption & Operation	Distributed Generation Market Demand (dGen) Model (NREL)	Customer adoption and operation of DER	https://www.nrel.gov/analysis/dgen/
DER Adoption & Operation	dsgrid-flex (NREL)	Translates device-level data (e.g., TEMPO, ResStock) into flexibility models for grid modeling	https://www.nrel.gov/analysis/dsgrid.html

Feedback Loop Representation	**Existing Capability**	**Data Description**	**Link**
DER Adoption & Operation	dsgrid (NREL)	Provides standard interface for accessing high-resolution load and DER data	https://www.nrel.gov/analysis/dsgrid.html
Power System Costs & Loads	Cambium (NREL)	Future grid service values and emission rates	https://www.nrel.gov/analysis/cambium.html
Power System Costs & Loads	PRAS (NREL)	Bulk system reliability summary (LOLE, EUE) and hourly (LOLP) metrics	https://www.nrel.gov/analysis/pras.html
Power System Costs & Loads	Resource Planning Portal (LBNL)	Utility resource planning assumptions	https://emp.lbl.gov/projects/utility-resource-planning
Power System Costs & Loads	Least-cost Optimal Distribution Grid Expansion (LODGE) model (LBNL)	Least-cost portfolio of distribution system upgrades for integrating Community Solar	https://www.energy.gov/communitysolar/least-cost-optimal-distribution-grid-expansion-lodge-model
Power System Costs & Loads and DER Adoption & Operation	Annual Technology Baseline (ATB) (NREL)	Technology-specific cost and performance parameters for the electricity and transportation sectors	https://atb.nrel.gov/
Rates	Utility Rate Database (URDB) (NREL)	Current and historical electricity tariffs	https://openei.org/wiki/Utility_Rate_Database