OLSON, BZDOK & HOWARD

May 19, 2022

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-Filing

RE: MPSC Case No. U-20836

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Direct Testimony of Douglas B. Jester on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan;

Exhibits MEC-1 through MEC-13; and

Proof of Service.

Sincerely,

Digitally signed by Christopher M. Bzdok
DN: cn=Christopher M. Bzdok, email=chris@envlaw.com, c=US
Date: 2022.05.19 14:46:24 -04'00'

Christopher M. Bzdok
chris@envlaw.com

xc: Parties to Case No. U-20836

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	U-20836

TESTIMONY OF DOUGLAS B. JESTER

ON BEHALF OF

MICHIGAN ENVIRONMENTAL COUNCIL,
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, AND
CITIZENS UTILITY BOARD OF MICHIGAN

May 19, 2022

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DIRECT TESTIMONY OF DOUGLAS B. JESTER
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I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Douglas B. Jester. I am Managing Partner of 5 Lakes Energy LLC, a Michigan limited liability corporation, located at Suite 218, 220 MAC Avenue, East Lansing, Michigan 48823.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Environmental Council ("MEC"), Natural Resources Defense Council ("NRDC"), Sierra Club ("SC"), and the Citizens Utility Board of Michigan ("CUB").

Q. Please summarize your experience in the field of utility regulation.

A. I have worked for more than 30 years in utility industry regulation and related fields. My work experience is summarized in my resume, provided as Exhibit MEC-1.

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. I have previously testified before the Michigan Public Service Commission ("Commission") in the following cases:

- Case U-17473 (Consumers Energy Company Plant Retirement Securitization);
- Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation);
- Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17317 (Consumers Energy 2014 PSCR Plan);

- Case U-17319 (DTE Electric 2014 PSCR Plan);
- Case U-17671-R (UPPCO 2015 PSCR Reconciliation);
- Case U-17674 (WEPCO 2015 PSCR Plan);
- Case U-17674-R (WEPCO 2015 PSCR Reconciliation);
- Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
- Case U-17688 (Consumers Energy Cost of Service and Rate Design);
- Case U-17689 (DTE Electric Cost of Service and Rate Design);
- Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
- Case U-17735 (Consumers Energy General Rates);
- Case U-17752 (Consumers Energy Community Solar);
- Case U-17762 (DTE Electric Energy Optimization Plan);
- Case U-17767 (DTE General Rates);
- Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
- Case U-17895 (UPPCO General Rates);
- Case U-17911 (UPPCO 2016 PSCR Plan);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- Case U-17990 (Consumers Energy General Rates);
- Case U-18014 (DTE General Rates);
- Case U-18089 (Alpena Power PURPA Avoided Costs);
- Case U-18090 (Consumers Energy PURPA Avoided Costs);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- Case U-18091 (DTE PURPA Avoided Costs);
- Case U-18092 (Indiana Michigan Power Company PURPA Avoided Costs);
- Case U-18093 (Northern States Power PURPA Avoided Costs);

- Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
- Case U-18095 (Wisconsin Public Service Company PURPA Avoided Costs);
- Case U-18096 (Wisconsin Electric Power Company PURPA Avoided Costs);
- Case U-18224 (UMERC Certificate of Necessity);
- Case U-18232 (DTE Renewable Energy Plan);
- Case U-18255 (DTE Electric General Rates);
- Case U-18322 (Consumers Energy General Rates);
- Case U-18406 (UPPCO 2018 PSCR Plan);
- Case U-18408 (UMERC 2018 PSCR Plan);
- Case U-18419 (DTE Certificate of Necessity);
- Case U-20072 UPPCO 2017 PSCR Reconciliation);
- Case U-20111 (UPPCO Tax Cuts and Jobs Act of 2017 Adjustment);
- Case U-20134 (Consumers Energy General Rates);
- Case U-20150 (UPPCO Revenue Decoupling Mechanism Complaint);
- Case U-20162 (DTE General Rates);
- Case U-20165 (Consumers Energy Integrated Resource Plan);
- Case U-20229 (UPPCO 2019 PSCR Plan Case);
- Case U-20276 (UPPCO General Rates);
- Case U-20350 (UPPCO Integrated Resource Plan);
- Case U-20359 (I&M 2019 General Rate Case);
- Case U-20471 (DTE Integrated Resource Plan);
- Case U-20479 (SEMCO 2019 General Rate Case);
- Case U-20561 (DTE 2019 General Rate Case).;
- Case U-20591 (Indian Michigan Power Company IRP);

- Case U-20642 (DTE Gas 2020 General Rate Case).;
- Case U-20649 (Consumers Electric Voluntary Green Pricing).;
- Case U-20650 (Consumers Gas 2020 General Rate Case;
- Case U-20697 (Consumers Electric 2020 General Rate Case);
- Case U-20713 (DTE 202 Voluntary Green Pricing);
- Case U-20874 (Alpena Power 2022-23 EWR Plan Case);
- Case U-20875 (Consumers Energy 2022-23 EWR Plan Case);
- Case U-20876 (DTE Electric 2022-23 EWR Plan Case);
- Case U-20877 (Indiana Michigan 2022-23 EWR Plan Case);
- Case U-20878 (NSP 2022-23 EWR Plan Case);
- Case U-20879 (UPPCO 2022-23 EWR Plan Case);
- Case U-20880 (UMERC 2022-23 EWR Plan Case);
- Case U-20881 (DTE Gas 2022-23 EWR Plan Case);
- Case U-20882 (MGU Gas 2022-23 EWR Plan Case);
- Case U-20883 (SEMCO Gas 2022-23 EWR Plan Case);
- Case U-20889 (Consumers Karn Retirement Securitization);
- Case U-20963 (Consumers Energy Electric Rate Case);
- Case U-21015 (DTE Securitization Case);
- Case U-21048 (Consumers Energy 2022 PSCR Plan);
- Case U-21081 (UMERC 2021 IRP); and
- Case U-21090 (Consumers Energy 2021 IRP).

Additionally, I have testified as an expert witness before the Public Utilities Commission of Nevada in Case No. 16-07001 concerning the 2017-2036 integrated resource plan of NV Energy; and before the Missouri Public Service Commission in Case Nos. ER-2016-0179, ER-2016-0285, and ET-2016-0246 concerning residential rate design and electric vehicle ("EV") policy, revenue requirements, cost of service, and rate design. I testified before the Kentucky Public Service Commission in Case No. 2016-00370 concerning municipal street lighting rates and technologies. I testified before the Massachusetts Department of Public Utilities in Case Nos. DPU 17-05 and DPU 17-13 concerning EV charging infrastructure program design and cost recovery. Before the Rhode Island Public Utilities Commission, in case 4780 I testified concerning Advanced Metering Infrastructure and EV charging infrastructure. Before the Delaware Public Service Commission, I testified regarding EV charging infrastructure in case 17-1094. I testified before the Georgia Public Service Commission in Case No. 4822 concerning PURPA avoided cost. I also testified before the Colorado Public Utilities Commission in Cases No. 20A-0204E and 20A-195E concerning cost recovery for EV charging infrastructure.

I have also testified as an expert witness on behalf of the State of Michigan before the Federal Energy Regulatory Commission ("FERC") in cases relating to the relicensing of hydro-electric generation and have participated in state and federal court cases on behalf of the State of Michigan, concerning electricity generation matters, which were settled before trial.

Q. **What is the purpose of your testimony?**

A. I am testifying on behalf of MEC, NRDC, SC, and CUB regarding DTE Electric's performance and its implications in this case, including return on equity; strategies to improve DTE Electric's performance; DTE Electric's proposed electric vehicle charging infrastructure programs; distribution system planning; DTE Electric's "plant study" and related considerations in its calculation of capacity charges and cost of service study; residential rate design; and proposals regarding distributed generation.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit MEC-1: Resume of Douglas B Jester

Exhibit MEC-2: CUB Utility Performance Report

Exhibit MEC-3: Recent DTE Performance Graphs

Exhibit MEC-4: DTE Discovery Response on Rate Benchmarking

Exhibit MEC-5: Effect of Residential Electricity Usage on Rates

Exhibit MEC-6: Reliability vs Cost

Exhibit MEC-7: DTE Discovery Response on EV Projections

Exhibit MEC-8: DTE Discovery Response on Federal EV Funding

Exhibit MEC-9: Corrected Plant Study Exhibit A-32

Exhibit MEC-10: DTE Discovery Response on Circuit Load Profiles

Exhibit MEC-11: Corrected Exhibit A-16 F1.5 Capacity Cost Calculation

Exhibit MEC-12: DTE Discovery Response re Outflow and MISO

Exhibit MEC-13: RAP Demand Charges Paper

II. CASE OVERVIEW

Q. Please summarize DTE Electric's principal requests in this case.

A. DTE summarizes its requests in its application in this case.[1] Key elements of its application are:

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[1] U-20836 Amended Application, pp. 2-5.

- A claim of revenue deficiency of approximately $388 million (7.5% over current rates) in a projected test year of November 1, 2022 through October 31, 2023.[2]
- A request to increase revenue from each customer class and rate schedule as summarized in Attachment 2 to the Application. Aggregated across rate schedules, this includes a request to increase revenue from residential customers by approximately $232.866 million (8.8% over current rates), from secondary commercial customers by approximately $97.581 million (7.7% over current rates), from industrial customers by approximately $48.716 million (4.1% over current rates), and from lighting by approximately $9.061 million (13.2% over current rates).
- Requests to change provisions of various tariffs including Rider 10, Rider 18, and the Retail Service Access Rider and to add new rate schedules D1.11, D.12, D3.5, and Rider 21.[3]
- Requests to approve costs for several pilot programs.[4]
- A request to continue deferral of tree trimming surge costs for calendar 2023 and 2024[5] and for several other proposals including the Charging Forward program and costs associated with the time of use rate offering.[6]
- A request for cost recovery of variable employee compensation programs
- A request to increase return on equity to 10.25% with a permanent capital structure of approximately 50% equity and 50% debt. Return on equity authorized in DTE

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[2] *Id.*, paragraph 4.

[3] *Id.*, paragraph 10.

[4] *Id.*, paragraph 11.

[5] *Id.*, paragraph 12.

[6] *Id.*, paragraph 13.

Electric's last rate case, Case No. U-20561 was 9.9% with a permanent capital structure of 52.29% long-term debt and 47.71% equity.

- A request to continue the PSCR base established in Case No. U-15244.
- A request to approve a proposed capacity charge pursuant to the State Reliability mechanism established in MCL 460.6w.

Q. What factors drive the proposed incremental revenue requirement of approximately $388 million?

A. DTE Electric summarizes the drivers of this incremental revenue request in Attachment 1 to its application. In their presentation, the revenue increase is attributable to $409 million in increased rate base revenue requirements, $38 million in revenue for capital structure change, and offset by an increase in sales margin of $26 million and a reduction of $42 million in operations and maintenance.

The request for $409 million increase in rate base revenue results from an increase in rate base from $18.574 billion in the calendar 2020 historical test year[7] to $21.268 billion in the projected test year and a proposed increase in "required return" on rate base primarily due to changes in weighted average cost of capital from 5.32%[8] as approved in Case No. U-20561 to a proposed 5.56% in this case.

DTE Electric's projected overall return in the projected test year absent a rate increase is 4.23%. Using the Excel version of Exhibit A-11, Schedule A-1 provided to parties by DTE Electric, I determined that increasing overall return to only the 5.32% previously

[7] Exhibit A-1, line 1.

[8] Exhibit A-1, line 4.

authorized instead of the 5.56% proposed by DTE Electric in this case reduces the projected revenue deficiency from approximately $388.222 million to approximately $320.481 million; thus approximately $67.741 million of the requested revenue increase is due to DTE Electric's request to change overall return on rate base and approximately $320.481 million is due to changes in rate base net of changes in expenses. Adding back in the sales margin increase ($26 million) and the operations and maintenance expense reductions ($42 million) identified by DTE Electric in Attachment 1 to its application identifies that the revenue increase due to increase in rate base is approximately $388 million.

Q. What are the principal factors driving this increase in rate base?

A. Changes in rate base from the historical test year to the projected test year are shown in Exhibit A-12 Schedule B1. This Exhibit illustrates that the increase in rate base consists of an approximately $2.697 billion increase in Plant in Service and an approximately $0.545 billion reduction in Depreciation Reserve, offset by approximately $0.382 billion reduction in Construction Work in Progress and approximately $0.182 billion in working capital and a number of other small changes.

The increase in Plant in Service, broken down by function, can be readily seen in Exhibit A-13, Schedule C6 page 2. This exhibit illustrates that the change in Plant in Service (column (g) less column (b)) consists principally of an increase of approximately $.544 billion in Production Plant in Service, approximately $1.905 billion increase in Distribution Plant in Service, and approximately $0.276 billion increase in General Plant in Service. Production Plant in Service changes include a reduction of $.907 billion in Steam Plant offset by an increase of approximately $1.063 billion in Production Plant, Other and some increases in Nuclear and Hydraulic Production Plant.

The reduction in Depreciation Reserve is shown in Exhibit A-12, Schedule B3 to mostly consist of a reduction of approximately $1.023 billion in depreciation reserve for Production Plant and increases of approximately $0.313 billion and $0.156 billion in Distribution Plant and General Plant, respectively. The $1.023 billion reduction in depreciation reserve for Production Plant appears from workpapers to result primarily from coal-fueled steam plant retirements.

Thus, the drivers of increase in rate base are principally the retirement of old coal plant, replaced by the Bluewater Energy Center, maintenance investments in other Production Plant, and considerable investment in Distribution Plant. Investment in Distribution Plant drives approximately 70% of the revenue increase requested by DTE Electric in this case.

III. DTE ELECTRIC'S PERFORMANCE

Q. What is the relevance in this case of DTE Electric's performance?

A. A respected paper on this subject states:

> …some describe the role of regulation as "balancing" the interests of shareholders and consumers. A balance presumes opposition of interests. But customers' and shareholders' legitimate interests – reasonable prices, reasonable returns, satisfied customers, and satisfied shareholders – are consistent and mutually reinforcing. High quality performance and efficient consumption benefit multiple interests: consumers, shareholders, bondholders, employees, -- the environment and the nation's infrastructure. What regulation must balance is not competing private interests but competing components of the public interest – e.g., long-term vs short-term needs, affordable rates vs efficient price signals, environmental values vs global competitiveness.
>
> …Universal, reliable, safe service at reasonable rates doesn't happen by itself. In short, regulation is necessary to align private behavior with the public interest. Regulation defines standards for performance, then assigns consequences, positive and negative, for that performance. The purpose of regulation is performance.[9]

[9] Hempling, S. Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction. American Bar Association Section of Environment, Energy, and Resources. 2013.

DTE Electric's overall performance is relevant in judging whether its proposals are reasonable and prudent, and particularly in drawing attention to those aspects of this case that should be most carefully scrutinized. The Commission may also consider overall performance when it authorizes a level of return on equity, as a positive or negative consequence of DTE Electric's performance.

Q. What are the most important metrics to consider when evaluating DTE's performance?

A. Former Governor Snyder identified these as Adaptability, Reliability, Affordability, and Protection of the Environment. Adaptability is an attractive consideration, but I am not aware of any metrics that are systematically reported and allow a comparison of the adaptability of utilities. Reliability, Affordability, and Protection of the Environment contain most of components of the public interest that concern electric utilities. Exhibit MEC-2 is a report published by the Citizens Utility Board of Michigan in 2021, which was prepared by me and my staff at 5 Lakes Energy and undertakes such comparisons based on 2019 data. We are currently beginning to prepare a similar report based largely on 2020 data (these delays between the year on which we report and the publication date reflect lags in reporting of relevant data by the US Department of Energy's Energy Information Administration and the US Bureau of the Census). My assessment based on preliminary review of the data is that 2020 was a strong year for DTE in terms of reliability metrics. However, it was a good year across all of Michigan and the states adjacent to Michigan as a result, I assume, of a comparatively mild storm season that year. As many may recall, 2021 was a difficult year for DTE's reliability, and we show a worse set of reliability metrics for the 2021 reporting year.

Q. How should the Commission benchmark DTE's performance?

A. The Commission should focus on DTE Electric's performance relative to other utilities with respect to reliability, affordability, and protection of the environment. While it is possible and perhaps commendable that the Commission could establish its own set of expectations regarding DTE Electric's performance based on careful study of what combinations of outcomes are reasonably attainable, the Commission has not yet undertaken that task. Even if the Commission were to do so, a comparison to other utilities would be warranted. The best performance by actual utilities provides at least a rough guide as to what is achievable given current technology, business practices, and regulatory effectiveness.

Exhibit MEC-3 is a set of graphs that I prepared, using 2019, 2020, and 2021 EIA data (for any given figure I used the most contemporary available data), that compare DTE Energy's performance on reliability, affordability, and environmental responsibility to that of all states, with a focus on other states in the region (Illinois, Indiana, Ohio, and Wisconsin) which I believe are the best available states against which to benchmark DTE Electric's performance, as they have similar climates, geography, and ages of infrastructure. For a broader comparison, I also suggest we benchmark DTE Electric's performance against that of similar-sized investor-owned utilities ("IOUs") nationwide, as similarly large utilities are likely to serve similar geographic and demographic variation and will face similar management issues and revenue requirements. In my analysis, I have taken "similarly sized" to be IOUs serving over one million total customers. There are thirty-four IOUs nationwide that fit this profile.

Q. How should the Commission assess DTE Electric's reliability?

A. Electricity is essential to modern life. As the U.S. moves towards decarbonizing its economy through electrification, electric reliability will become increasingly important, and, in turn, a more reliable electric system will promote electrification. Much of the public policy discussion about electric utility reliability focuses on what utility regulators and utilities call Resource Adequacy. Resource Adequacy ensures that there is sufficient power generation capacity to satisfy utility customer peak demand. However, loss of electricity supply due to generation or transmission problems accounts for only about 1% of outage minutes nationally. Power outages that utility customers experience on a regular basis are not caused by insufficient generation capacity or long-distance transmission, but by breakdowns in the electricity delivery system—the distribution grid. Distribution breakdowns may occur due to storms breaking powerlines, wildfires, animals touching pairs of power lines and causing a "short," equipment failures, and many other reasons.

The electric power industry, led by the Institute of Electrical and Electronics Engineers ("IEEE") has determined that the overall measure of an electric utility's reliability is the average number of minutes outage per year per customer, calculated by a method referred to as the System Average Interruption Duration Index ("SAIDI"). Important elements of SAIDI are the average number of outages per customer per year and the average duration of each customer outage. Outages per customer per year are computed by a method referred to as the System Average Interruption Frequency Index ("SAIFI") while the average duration of each customer outage is computed by a method referred to as Customer Average Interruption Duration Index ("CAIDI"). CAIDI measures the average time for the utility to restore power to a customer after an outage starts.

Beginning in 2013, the Energy Information Administration ("EIA") of the US Department of Energy began collecting annual reports of SAIDI, SAIFI, and CAIDI from utilities and publishing those data in annual compilations, which may be downloaded from http://www.eia.gov/electricity/data/eia861/. The EIA collects SAIDI and SAIFI metrics with and without Major Event Days ("MED"). Major Event Days are a statistical classification, defined by the Institute of Electrical and Electronics Engineers ("IEEE"), of large outage events such as ice storms, windstorms, and hurricanes, that can materially affect annual reliability statistics. While reliability metrics that include Major Event Days can fluctuate greatly year-to-year, they provide a more accurate representation of customer experience than metrics excluding Major Event Days. For this reason, reliability data are presented with and without Major Event Days.

It is also worth noting that excluding Major Event Days does not exclude all effects of major storms, since the process of restoring service after a storm causes an outage will reduce the number of customers without service below the threshold to classify a day as a Major Event Day even though most outages on that day are attributable to the storm a few days earlier. Thus, outage data including Major Event Days is inclusive of all days but outage data excluding Major Event Days is not necessarily representative of fair weather.

I recommend that the Commission assess DTE Electric's reliability by comparing its performance to that of other utilities, and metrics should include, among others, SAIDI, SAIFI, and CAIDI. I have included graphs comparing Michigan and DTE Electric to the reliability of electric service in each of the other states and graphs comparing DTE Electric to similarly-sized IOUs in Exhibit MEC-3. As can be seen in those graphs,

- DTE Electric's SAIDI including MED in 2020 was slightly better than the weighted average of Michigan utilities, but the average of Michigan utilities was worse than the performance of all but 18 other states. Furthermore, DTE Electric's SAIDI including MED was worse than the weighted average scores of all other states in the region, and was just worse than the median of comparably sized utilities nationwide;
- DTE Electric's SAIDI excluding MED in 2020 was somewhat better than the weighted average of Michigan utilities but was worse than the performance of all but 15 states, while Michigan's average was worse than the performance of all but 9 states; However, DTE Electric's SAIDI excluding MED was worse than the weighted average scores of all other states in the region, and was worse than all but 10 comparably sized utilities nationwide;
- DTE Electric's SAIFI including MED in 2020 was somewhat better than the weighted average of Michigan utilities and was better than the median of the country with 30 states having worse performance, while 22 states were worse than Michigan's average. DTE Electric performed better than the weighted average of SAIFI including MED than Indiana and Ohio, but substantially worse than Illinois or Wisconsin;
- DTE Electric's SAIFI excluding MED in 2020 was slightly better than the weighted average of Michigan utilities but was worse than the median of the country with 22 states having worse performance, while 19 states were worse than Michigan's average. DTE Electric performed better in its weighted average SAIFI excluding MED than Ohio, but worse than Indiana and substantially worse than Illinois and Wisconsin;

- DTE Electric's CAIDI including MED in 2020 was somewhat better than the weighted average of Michigan utilities, but was worse than all but 15 states, with Michigan being worse than all but 12 states. DTE Electric's CAIDI including MED was somewhat better than the weighted average of Illinois but was worse than Indiana, Ohio, and Wisconsin);
- DTE Electric's CAIDI excluding MED in 2020 was somewhat better than the weighted average of Michigan utilities but was worse than all but four states, while Michigan was worse than the performance of all states except West Virginia. DTE's CAIDI excluding MED was worse than the weighted average scores of all states in the region.

In short, DTE's outage frequency is near median but its power restoration performance is quite poor. Furthermore, DTE underperforms under normal operating conditions with comparatively worse reliability rankings on all metrics without MED; this may be partly due to the hangover into non-MEDs in the storm recovery process.

Q. Are there important trends in DTE Electric's reliability?

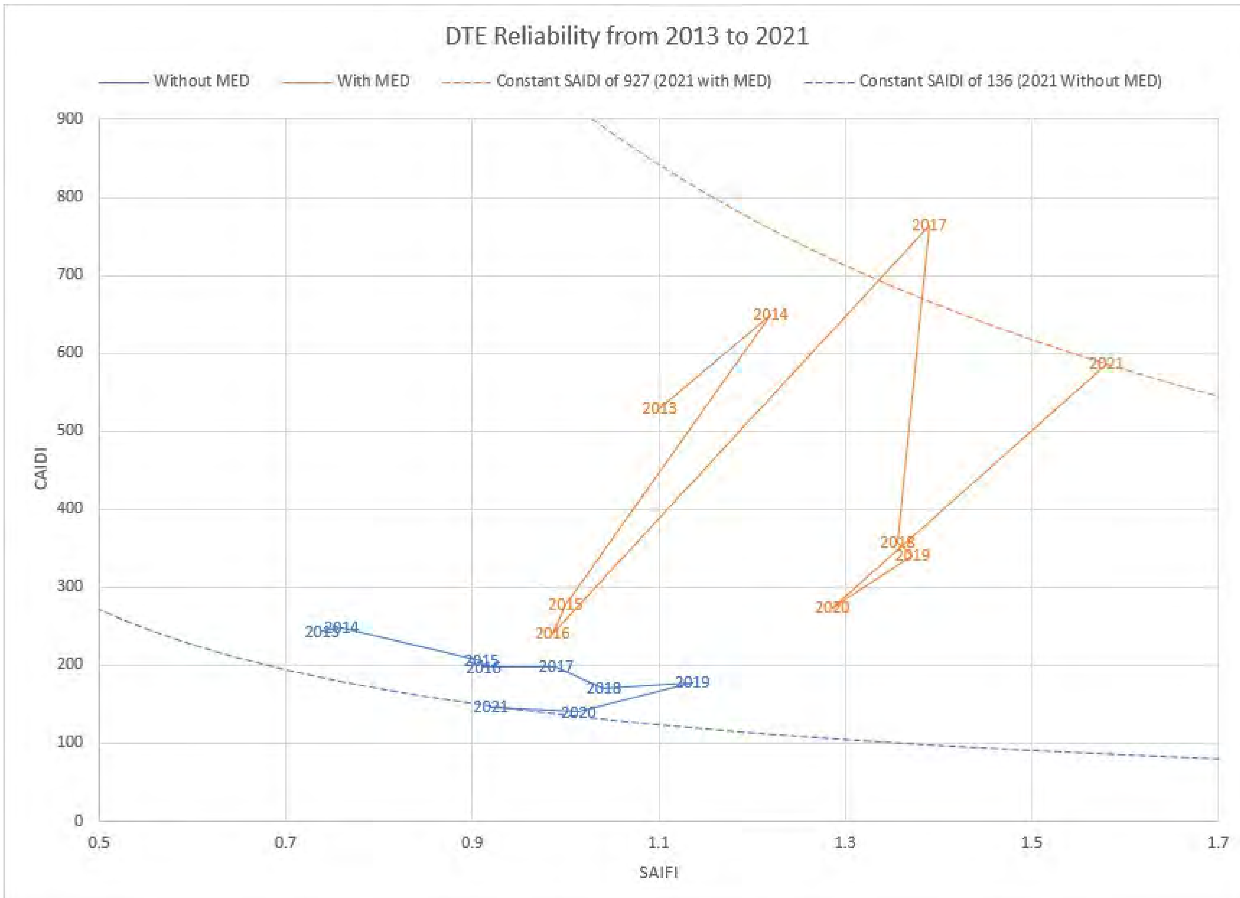
A. DTE Electric presented the following graph in its Distribution Grid Plan.[10] This graph shows that DTE Electric has long been in the fourth quartile of reliability performance relative to other utilities. Although in 2020, their performance improved, it likely reverted in 2021.

[10] Exhibit A-23, pp. 121-123 of 568.

Figure 2. SAIDI Performance (Minutes) *

The following graph, which I prepared, illustrates trends in DTE Electric's SAIFI and CAIDI including and without MEDs including 2021. This graph illustrates that SAIFI and CAIDI without MEDs may have improved in recent years but that Major Event Days dominate DTE Electric's outage statistics and appear to be worsening, particularly with respect to SAIFI. There may have been improvements in CAIDI in the period 2018 through 2020 but 2021 data leave that an open question.

Figure 1. DTE Distribution Reliability from 2013 to 2021



Q. How should the Commission assess DTE Electric's affordability?

A. Electricity bills often have many components – fixed monthly charges, charges based on the customer's peak rate of power usage in the billing month or previous year, and a charge per kWh or electricity are common billing determinants. The ways in which utilities assign costs to these various components of the bill vary greatly amongst utilities, amongst classes of customers, and across states. Customers, however, are getting value from each kWh of electric energy, so dividing the total bill by the kWh used is a reasonable way to compare utility costs.

EIA collects monthly data from each utility in each state on the amounts of electricity sold and revenue from electricity by customer class. Customer classes include residential, commercial, industrial, transportation, and others with almost all electricity delivered in most states going to the first three classes. EIA makes these data available through an Electricity Data Browser on its website, at http://www.eia.gov/electricity/data/browser/. The most recent complete calendar year available is 2021 and it is used here to compare the cost of electricity in the various states, reported in cents per kWh.

As one of the essentials of modern life, the cost of electricity can be important both to households who must choose between electricity consumption and other goods and services; and also to competitive industry.

The affordability of electricity is a nuanced matter. For households in different regions of the country, the local climate and the availability of alternative heating fuels can affect the amount of electricity they consume. Expenditures on electricity and other heating fuels must be considered in context of income. Comparison of total household energy expenses and total household energy expenses as a share of household income are important measures of affordability.

Commercial and industrial users of electricity are less affected by local climate and available heating fuels, so the technologies of commerce and production can be more consistent from place to place. However, different types of businesses have very different energy requirements and often are clustered in different states for reasons having little to do with energy costs. Thus, total commercial and industrial energy cost is not a good basis for comparison; cost per kWh comparison is more useful.

I recommend that the Commission assess DTE Electric's affordability by comparing its costs per unit of electricity by customer class nationally, to other utilities in Michigan, to neighboring states, and comparably sized investor-owned utilities throughout the country.

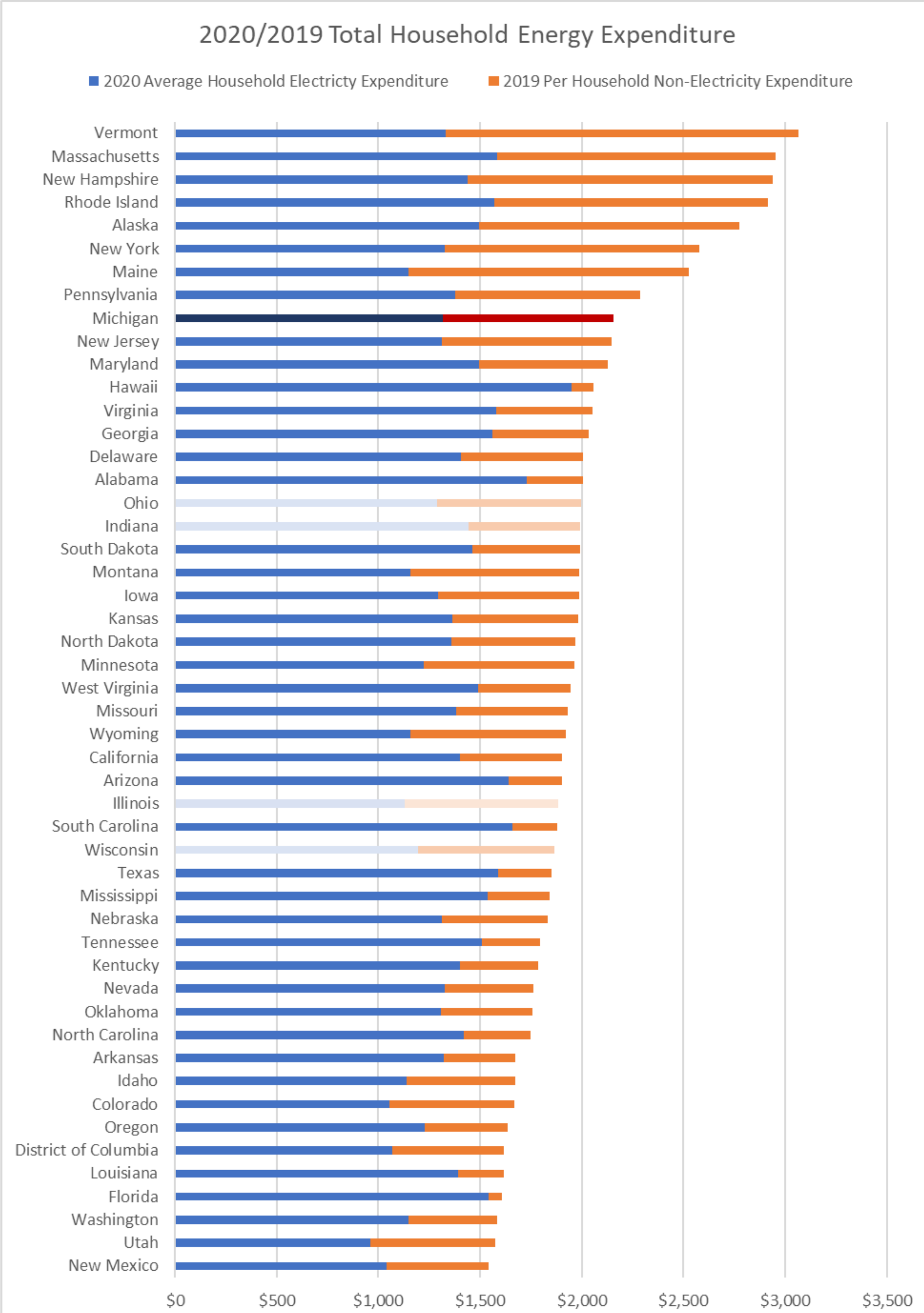
Most importantly for residential customers, the Commission should consider total household energy bills in both absolute cost and in relation to income. Household energy bills include heating fuels. DTE Electric's customers use a variety of heating fuels and often obtain their heating fuel from other utilities or direct fuel providers (DTE's gas service territory is not coincident with its electric service territory). As a result, I recommend comparing the Michigan average household bills to those of other states, as more specific utility-level comparisons are not practical for this metric. The affordability of household energy bills also depends on household income, so I recommend considering Michigan household energy bills as a percentage of household income. I have included such graphs in Exhibit MEC-3. As can be seen in those graphs,

- DTE Electric's average industrial electricity rate in 2021 was slightly lower than the weighted average of Michigan utilities, but because of the relatively low variation in industrial rates across much of the United States this caused DTE Electric to have rates lower than only 18 states, while Michigan's average was lower than that of 15 states. DTE Electric and Michigan were both higher than the US average industrial rate. Compared to neighboring states, DTE Electric had more expensive rates than Indiana, Illinois, and Ohio, but a lower rate than Wisconsin. Compared to similarly sized utilities, DTE Electric's Industrial rates were below the median and less expensive than any similarly sized utilities in the region;
- DTE Electric's average commercial rate in 2021 was slightly lower than the weighted average of Michigan utilities, and was higher than all but 13 states, while Michigan's average was higher than all but 12 states. DTE Electric and Michigan were both higher than the US average commercial rate. Compared to

states in the region, DTE Electric had the highest commercial rate. Compared to similarly sized utilities, DTE Electric's commercial rates were near the median;

- DTE Electric's average residential rate in 2020 was slightly above the weighted average of Michigan utilities, and was higher than all but 9 states, while Michigan's average was higher than all but 10 states. DTE Electric and Michigan both had higher than the US average residential rate. Compared to states in the region, DTE Electric had the highest residential rate. Compared to similarly sized utilities, DTE Electric's residential rates were higher than all but 8 of 34 companies and higher than all other comparably sized utilities in the region except for Consumers Energy, which had a slightly higher average residential rate in 2021.
- Michigan's average household energy (electricity plus heating fuel) bill in 2020/2019 (we used 2020's electricity costs, but other heating fuel costs from 2019, because these data have not yet been reported for 2020 by the EIA) was higher than all but 8 states, and substantially higher than that of any state in the region, and since DTE Electric's average residential rate is near though slightly higher than the Michigan average, Michigan's ranking likely represents DTE's relative position as well;
- Michigan's average household electricity plus heating bill as a percentage of household income in 2020/2019 was higher than all but 12 states and is notably higher than that of any neighboring state.

In short, DTE's industrial rates are competitive, but its commercial and residential rates are relatively high. In order to emphasize the importance of affordability, I present below the principal graph concerning affordability that is included in Exhibit MEC-3.

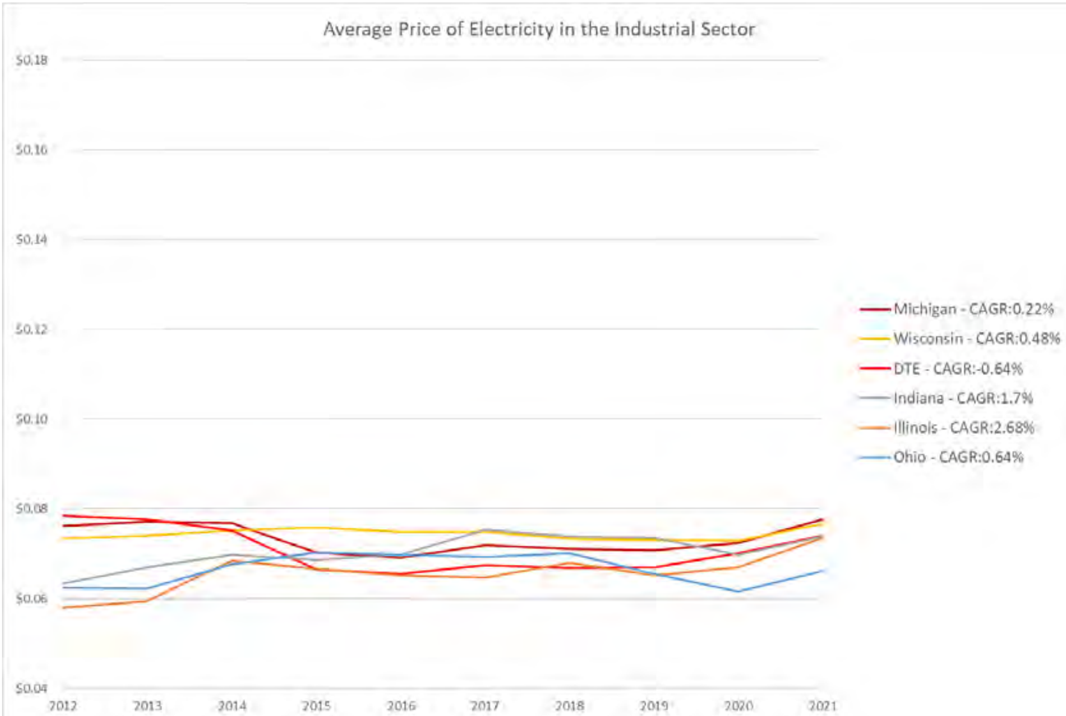


Michigan's residential energy bill affordability is noticeably worse than median amongst the states and worse than any state in the region. Only Alaska and the mostly high-income northeastern states have significantly higher household energy bills than Michigan residents.

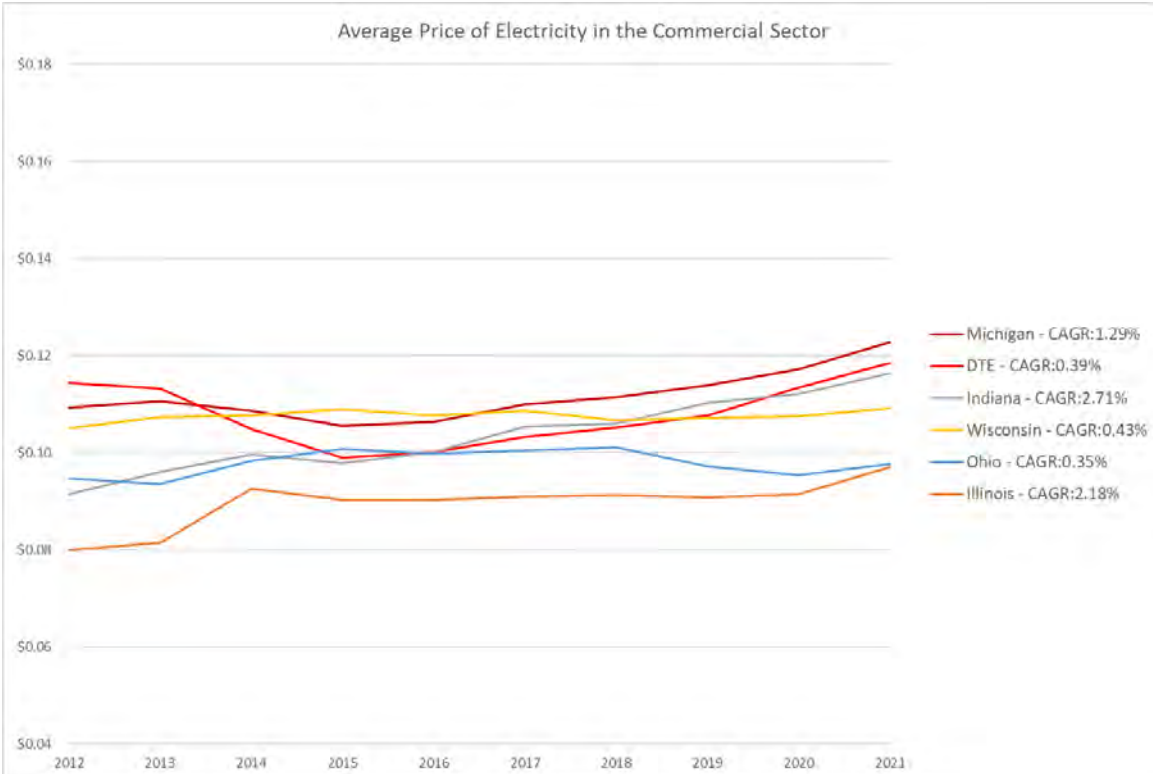
Q. Are there important trends in DTE Electric's comparative rates?

A. Yes. The following graph shows the average cost per kWh for industrial customers of DTE, in Michigan, and in neighboring states. This illustrates that industrial rates have been relatively stable and have grown less than the US Consumer Price Index, which had a compound annual growth rate ("CAGR") of 1.88% over the same period.[11] DTE Electric's industrial rates have gone down relative to constant consumer purchasing power. DTE Electric's industrial rates have increased in general consistency with the rest of our region.

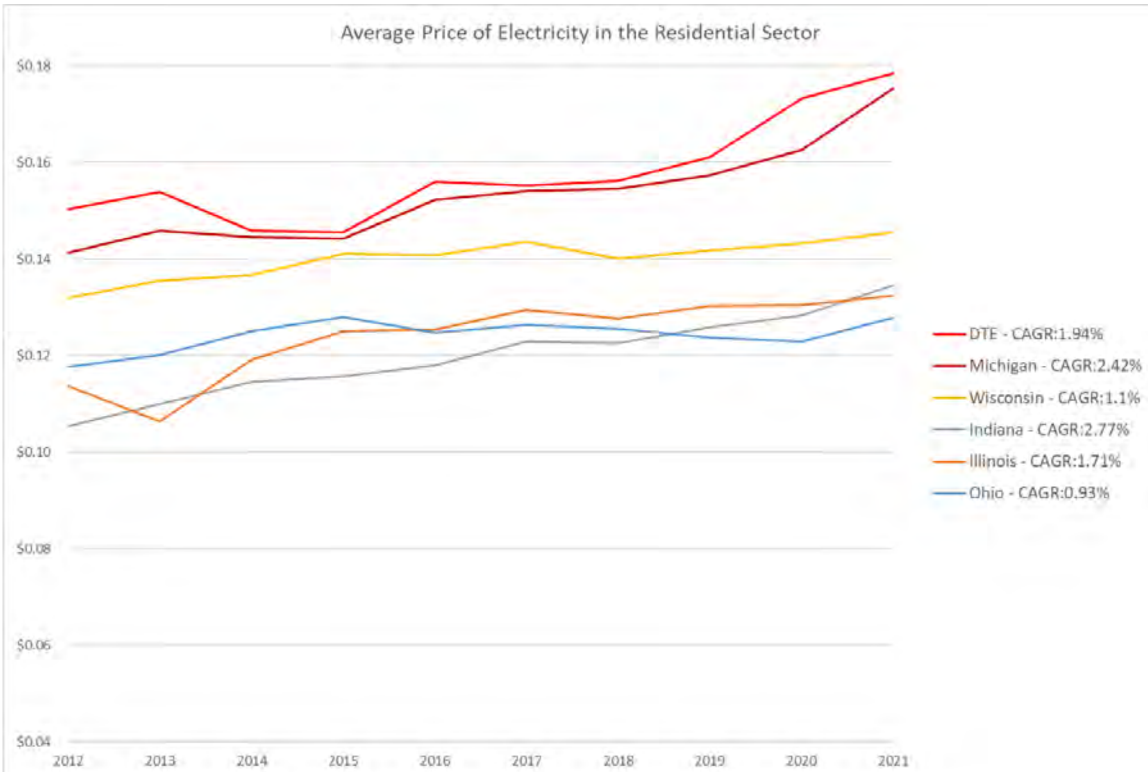
[11] Calculated from data obtained from FRED, an economic data service of the St Louis Federal Reserve Bank, available from [Inflation, consumer prices for the United States (FPCPITOTLZGUSA) | FRED | St. Louis Fed (stlouisfed.org).](https://fred.stlouisfed.org)



The following graph similarly illustrates trends in average electricity cost per kWh for commercial customers of DTE Electric, in Michigan, and in neighboring states. This illustrates that commercial rates have been relatively stable and have grown less than the US Consumer Price Index, but that DTE electric and Michigan have recently increased commercial rates at a greater rate than has occurred in neighboring states. But for a decline in cost/kWh over the period 2012-2015, DTE Electric and Michigan electricity cost per kWh for commercial customers have been increasing faster than inflation.



The following graph similarly illustrates trends in average electricity cost per kWh for residential customers of DTE Electric, in Michigan, and in neighboring states. This graph illustrates that DTE Electric and Michigan cost per kWh for residential customers is higher than in neighboring states, is growing faster than in neighboring states, and is growing faster than inflation.



Q. Has DTE undertaken any effort to benchmark its rates?

A. Yes. Exhibit MEC-4 is a summary of DTE's benchmarking effort. It was produced as an attachment to discovery response AGDE-1.13. Among its conclusions are:

- DTE Electric has the highest residential rate growth in the Great Lakes region over the past five years.
- In 2020, DTE Electric's average residential rates were 31% above the U.S. average and 28% above the average in the region.
- By contrast, DTE Electric's business and industrial rates in the same year were below average in Michigan.
- The changes in DTE Electric retail rates compare unfavorably to the regional average over 1, 3, and 5-year periods.

These conclusions are consistent with my preceding analysis.

Q. How should the Commission assess DTE's environmental performance?

A. There are several aspects to an electric utility's impact on the environment, but the most ubiquitous and arguably most important in aggregate are rates of air emissions that cause public health problems and climate change. These can be compared across utilities using national databases. Other considerations such as uses of water, pollution discharges to water, impingement and entrainment of aquatic life, solid waste such as coal combustion residuals (including coal ash), and land management are important but harder to compare across utilities.

Fossil-fueled power plants emit many different pollutants into the air, but the largest quantities are:[12]

- Carbon dioxide (CO2) which is the principal gas causing climate change;
- Sulfur dioxide (SO2) which causes asthma attacks, cardiopulmonary diseases, acid rain, and is a chemical precursor to formation of small particles that when breathed cause several respiratory and other problems, miscarriages, and birth defects; and
- Nitrogen oxides (NOx) which cause respiratory problems including wheezing, asthma, and other breathing difficulties and is a chemical precursor to formation of small particles and ozone in the air that also cause numerous health problems.

Electric utilities report emissions of key pollutants from each power plant to the Environmental Protection Agency, which compiles this information and makes it available to the EIA, from whom it can be obtained from https://www.eia.gov/electricity/data/emissions/. Effects of air emissions on human health

[12] Many of the pollutants emitted in small quantities, such as heavy metals, are toxic and harmful despite being emitted in small quantities. Statistics on these pollutants are not compiled by EIA.

and the environment are often determined by the quantity of pollution released and, in the cases of sulfur dioxide and nitrogen oxides, by location relative to human population and natural resources.[13] However, as a measure of relative overall utility performance it is appropriate to consider emissions per unit of power generated.

I therefore recommend, given what data is readily available and comparable across utilities, that the Commission in this case assess DTE's environmental performance by comparing their emissions of carbon dioxide, sulfur dioxide, and nitrogen oxides per MWh. In future regulatory proceedings, I would strongly encourage the Commission, in partnership with other state regulatory agencies such as EGLE, to not limit evaluation of environmental performance to air emissions, but rather to look at the full range of environmental impacts that utility operations and electric power generation create.

However, because power generation is subject to shared ownership of power plants, bilateral sales of power, power pooling in regional markets, and other institutional arrangements that make it difficult to attribute emissions to the services provided by a particular utility, I recommend that in this proceeding the Commission consider the level of emissions per MWh for Michigan as a whole and qualitatively consider DTE's comparative performance amongst Michigan utilities based on the Commission's knowledge of DTE's power supply arrangements. I have included graphs of Michigan's emissions intensity in Exhibit MEC-3. As can be seen in those graphs,

[13] Note this data also does not take into account cumulative impacts from multiple sources emitting pollutants in close proximity. However, cumulative impacts are an important consideration when fully vetting air emission impacts on public health and the environment.

- Michigan's average carbon dioxide intensity of electric generation in 2020 was somewhat worse than the national median, with 14 states having greater carbon dioxide intensity of electric generation. However, Michigan's average carbon dioxide intensity is lower than that of any state in the region except Illinois;
- Michigan's average sulfur dioxide intensity of electric generation in 2020 was considerably worse than the national median, with only 10 states having greater sulfur dioxide intensity of electric generation. Compared to states in the region, Michigan's average sulfur dioxide intensity is lower than that of Indiana and Ohio, but higher than Illinois and Wisconsin;
- Michigan's average nitrogen oxide intensity of electric generation in 2020 was somewhat worse than the national median, with 12 states having greater nitrogen oxide intensity of electric generation. Compared to neighboring states, Michigan's average nitrogen oxide intensity is lower than that of Indiana but higher than Illinois, Ohio, or Wisconsin.

Subject to the Commission's approval of a proposed settlement in Consumers Energy's Integrated Resource Plan Case No. U-21090, DTE Electric will be the only Michigan utility still using significant coal generation after 2025 and has to a significant degree been replacing coal with new gas generation rather than clean energy resources. Thus, DTE Electric's current and projected performance on these metrics is likely materially worse than statewide average emissions intensity.[14]

[14] Michigan's recent historical performance shows improving statistics for air emissions intensity, but at a pace that is middle-of-the-pack in terms of annual percentage improvements when compared to other states.

Q. Please summarize DTE's overall performance.

A. Based on the data presented above, DTE's performance is somewhat worse than the national median in all respects.

DTE's restoration of power following an outage, measured by CAIDI, was particularly poor and that also caused its overall reliability as measured by SAIDI to be comparatively poor despite a near median, but deteriorating in trend, frequency of outages as measured by SAIFI. On SAIDI metrics, DTE has worse weighted average performance than any neighboring state both with and without major event days. Although DTE has, in trend, improved its CAIDI scores over time, its SAIFI scores have trended worse, with 2020 being the apparent exception.

DTE's rates were worse than both the average and median rates nationwide and are noticeably worse for residential and commercial customers than for industrial customers. Affordability of household energy was also materially worse than the national median.

Michigan's emissions intensity of electric generation was worse than average and is especially poor for sulfur dioxides. DTE Electric's continuing use of large amounts of coal generation is a primary driver of these higher emissions.

Q. In light of DTE Energy's performance, what do you recommend to the Commission regarding authorized return on equity?

A. I recommend that the Commission deny DTE Energy's request for an increase in authorized return on equity from 9.9% to 10.25% and say in doing so that this is in part based on DTE Electric's performance. Testimony by David Garrett on behalf of MEC and CUB discusses the Company's request and provides recommendations on setting the return on equity in this case. This performance analysis provides additional support for the Commission to reduce the Company's authorized ROE.

Q. Are there additional reasons to consider reducing return on equity?

A. Yes. It is well established that regulated utilities that create firm value through investments that earn returns are incented to inefficiently invest capital, especially if the authorized return on equity is high.[15] A reduction in return on equity could reduce DTE Energy's incentive to be economically inefficient in its capital expenditures on its distribution system.

IV. <u>STRATEGIES TO IMPROVE DTE ELECTRIC'S PERFORMANCE</u>

Q. You presented evidence earlier in this testimony that Michigan and DTE Electric have high residential rates compared to other states and IOUs. Can you provide further diagnosis as to the causes of these high rates?

A. Yes. Industrial rates are predominantly based on allocation of production and transmission costs, with only modest distribution costs. In this case, DTE Electric's proposed revenues from primary customer rate schedules for power supply total \$987.303 million[16] and for distribution they total \$36.075 million. Primary customers include large commercial as well as industrial, so the industrial ratio of power supply cost to total cost is likely even higher. It is reasonable, therefore, to consider that industrial customer costs per kWh are a reasonable proxy for overall power supply costs in a state and that the difference between

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[15] Averch, Harvey; Johnson, Leland L. (1962). "Behavior of the Firm Under Regulatory Constraint". *American Economic Review*. **52** (5): 1052–1069.

[16] Exhibit A-16 Schedule F2, p. 3.

residential and industrial costs are attributable to power supply cost allocation policy and costs of distribution.

It is also commonly thought that distribution costs include customer costs and geographical coverage costs that do not vary with electricity sales per distribution customer.[17] Exhibit MEC-5 page 1 shows the results of calculating for each state in 2021 the average annual residential electricity sales per customer, the average annual residential electricity bill per residential customer, and subtracting the product of the average annual residential electricity sales per customer with the average cost per kWh of industrial electricity sales in that same state. Subtracting power usage times the average industrial rate from the total residential bill is a reasonable approximation of the costs of distribution to residential customers. The superimposed line shows the results of a regression of the resulting annual bill per customer net of power supply costs proxied by industrial rates vs annual electricity sales per customer. Exhibit MEC-5 page 2 shows the results of converting these data and the regression into average residential cost per kWh less average industrial cost per kWh versus annual average residential electricity sales per customer.

The regression line in this analysis, particularly the representation on page 2 of Exhibit MEC-5 shows that annual sales per customer does have an effect on residential rates, but that Michigan and DTE residential rates are nonetheless quite high compared to the regression line. Further, the difference between residential and industrial prices in neighboring states is quite close to the regression line. Wisconsin, which has annual electricity sales per residential customer that is only slightly higher than in Michigan, nonetheless has residential rates that differ from industrial rates by an amount quite close to the regression line and considerably less than that difference in Michigan. We can conclude that Michigan's and DTE Electric's comparatively low annual residential sales does not explain Michigan nor DTE Electric's high residential rates.

Mathematically, this leaves only three possible explanations for our high residential rates:

- Michigan's allocation of power supply costs per kWh sales to industrial and residential customers differs systematically from practices in most other states, with a larger than normal cost allocation to residential customers;
- Michigan's utilities, including DTE Electric, have higher distribution costs in relation to customer count and electricity sales than other utilities; or
- Michigan's utilities allocate a greater share of distribution costs to residential customers than other utilities.

Q. Should the Commission examine these three possible explanations to determine the contribution of each to our Michigan's and DTE Electric's high residential rates?

A. It would be useful and relevant for the Commission to consider an analysis of the potential causes for Michigan's high residential rates compared to nearby and comparable utilities, particularly given the high and rising distribution costs that are driving high and rising residential rates. However, this rate case is not the appropriate forum for such an analysis, given the limitations of time and effort imposed by the case schedule and the already broad scope of issues in this rate case. The Commission should direct DTE Electric and Commission Staff, with advice and review by stakeholders, to develop the necessary data and provide an analysis in DTE Electric's next rate case, next Distribution Grid Plan, or in a separate informational docket. This analysis would require review of filings and public utility commission orders for select IOUs across the region to assess costs and cost allocations and build up a database for further analysis. The Commission should require the study to examine the effects of financial parameters such as return on capital, depreciation rates, production cost allocation, distribution cost allocation, and electricity sales per household.

Q. What additional strategies does your analysis suggest the Commission might take to address high residential rates?

A. As part of the study just recommended, the Commission should include an examination of whether DTE Electric's method of allocating costs to customer classes accurately reflects cost of service or has acquired a bias toward shifting costs onto residential customers. I discuss production cost of service later in this testimony.

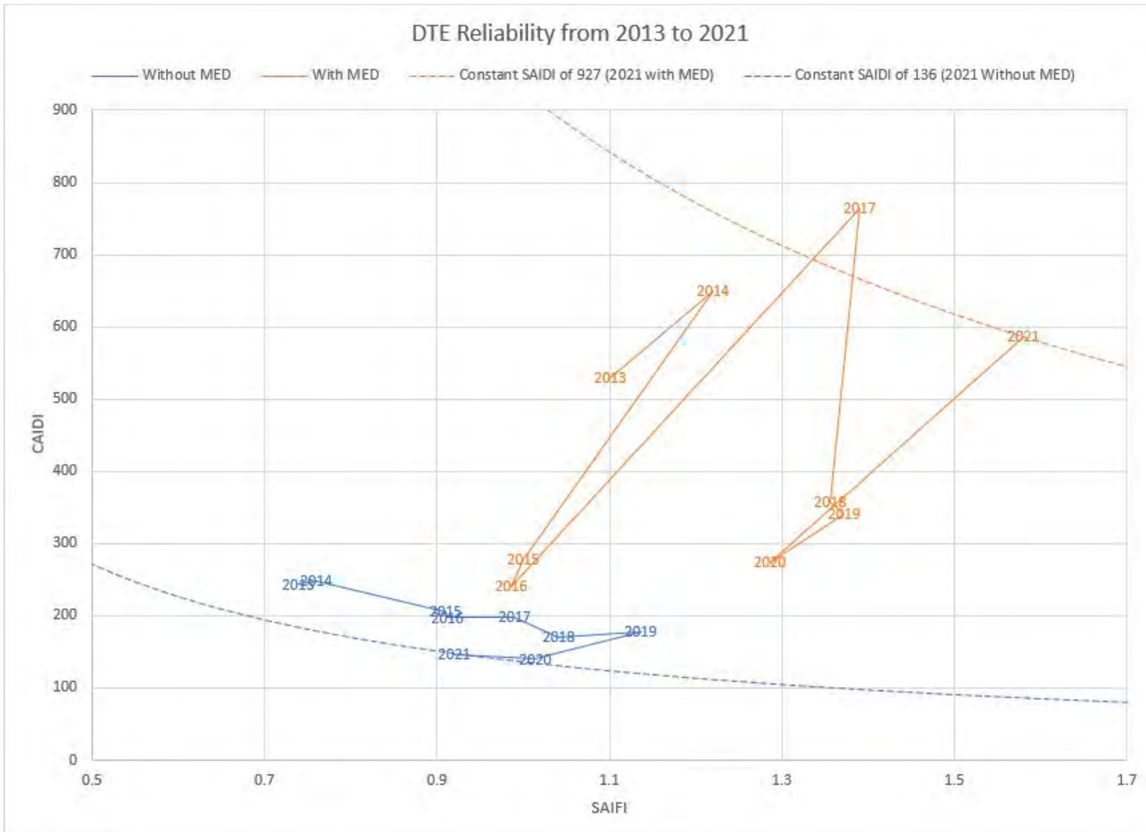
The Commission should be diligent about both evaluating the prudence of DTE Electric's distribution system spending and about prioritizing authorized programs and costs for their cost-effectiveness in improving reliability. My colleague Robert Ozar discusses the prudence of some of DTE Electric's proposed distribution system costs in this case, including the cost to other customers of new customer additions as determined by Contributions in Aid of Construction ("CIAC"). Both Mr. Ozar and I discuss prioritization of distribution system spending.

The Commission should consider that transportation and building electrification will increase electricity sales per household and may thereby help to dilute DTE Electric's high distribution system costs per customer, lowering rates.

Q. You presented evidence earlier in your testimony that Michigan and DTE Electric have comparatively poor distribution system reliability. Can you provide further diagnosis as to the causes of this poor reliability?

A. Michigan, and DTE, have high residential rates and poor reliability. It is therefore unsurprising that insufficient spending does not appear to explain this comparatively poor distribution reliability. Exhibit MEC-6 displays SAIDI with MEDs (on page 1) and SAIDI without MEDs (on page 2) for the various states and for DTE vs the difference between actual and expected distribution costs per residential customer. Expected distribution costs for each state and for DTE are calculated from the regression line in Exhibit MEC-5 between annual electricity sales per residential customer and the annual electricity bill per residential customer. It is readily apparent that there is not a meaningful relationship between utility revenues per customer and SAIDI, either across the country or within Michigan's region. We must look to other explanations.

The following figure is identical to Figure 1 presented earlier in my testimony. This figure traces DTE Electric's SAIFI and CAIDI, with and without MEDs, over time. This graph provides some indications about DTE Electric's reliability problems, when interpreted in context of other information.



Major storm events clearly have an effect on SAIFI and CAIDI with MEDs. Bearing in mind that SAIFI and CAIDI without MEDs includes the days following storms when enough customers have been restored that those days are not classified as MEDs but many customers may still be without service as a hangover from the storm, it is not surprising that the pattern of SAIFI and CAIDI without MEDs echoes the pattern of SAIFI and CAIDI with MEDs.

An optimistic interpretation of the pattern of SAIFI and CAIDI including MEDs is that although the numbers of outages, as measured by SAIFI is higher, CAIDI has improved in recent years. This interpretation is supported by DTE Electric's presentation of reliability data in the Distribution Grid Plan.[18]

DTE Electric represents that historically trees cause two-thirds of the time that customers spend without power[19] or, alternatively, that trees/wind cause 73.9% of the time that customers spend without power.[20] Trees sometimes cause outages in fair weather but it is clear that most tree-related outages are associated with storms, so that trees likely contribute an even larger share of outage minutes associated with MEDs than without MEDs. DTE Electric began a tree-trimming surge in 2016, including what they refer to as Enhanced Tree Trimming and an effort to reduce their tree-trimming cycle to 5 years. The surge is not expected to be completed until 2024[21], but significantly more of DTE Electric's distribution system has been through tree-trimming in each year since 2016.[22] DTE Electric claims that those circuits that have been trimmed to the new standards have 60% fewer outages and shorter outage durations than those that have not.[23] These factors suggest that much of DTE Electric's reliability problem is due to its historically long tree-trimming cycle of approximately 8.5 years[24] and that persistent and perhaps even accelerated tree trimming will significantly improve DTE Electric's reliability performance. The testimony

[18] Exhibit A-23, Schedule M1, pp. 122-123 of 568.

[19] Exhibit A-23, Schedule M1, p. 11 of 568.

[20] Exhibit A-23, Schedule M1, p. 126 of 568.

[21] Identified as 2025 in Exhibit A-23, p. 11 but accelerated to 2024 according to the Direct Testimony of S. Hartwick, SMH-30:4-8.

[22] Exhibit A-23, Schedule M1, p. 11 of 568.

[23] Exhibit A-23, Schedule M1, p 11 of 568.

[24] Hartwick Direct, SMH-35:4-6.

of DTE Witness Hartwick is persuasive in this regard. It is also notable that DTE Electric's 4.8kV hardening program includes significant tree trimming.

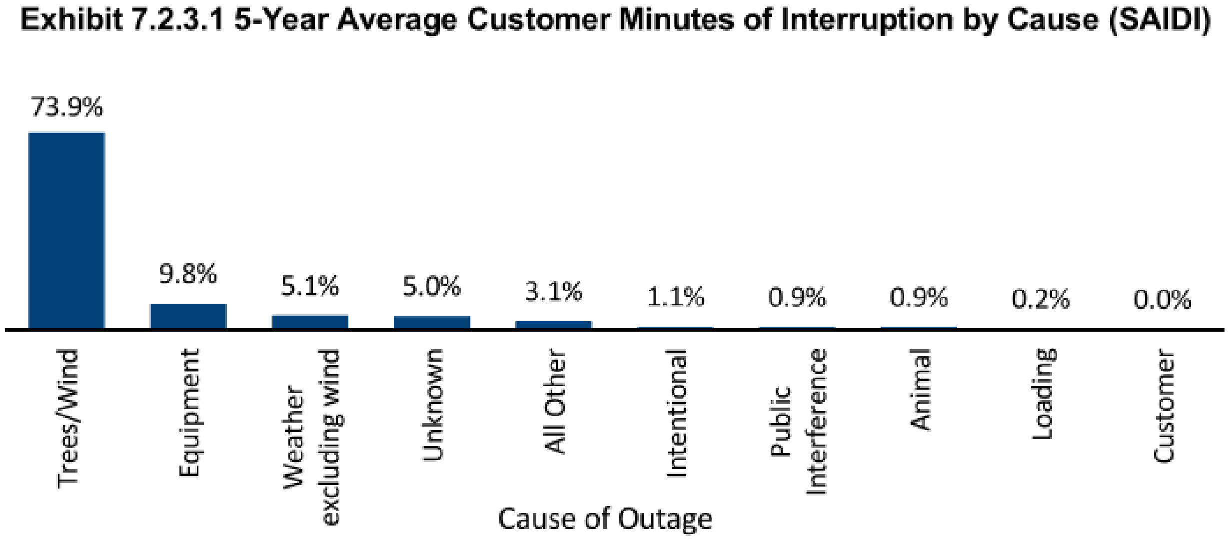
Q, Has DTE provided a projection of total system reliability improvements associated with tree trimming and its other investments?

A. Unfortunately, no. DTE Electric does not appear to have provided a projection of total-system reliability that would result from the improved tree-trimming program alone. Although DTE included projections of overall reliability improvements associated with its capital and tree trimming investments in the Distribution Grid Plan (section 5.3), there is no assessment of the reliability before the tree trimming surge, since the tree trimming, and as a result of other strategic spending aimed at improving reliability. Rather, the Distribution Grid Plan provides graphs indicating it will reach second and first quartile SAIDI and SAIFI reliability by 2025 if the Commission approves its strategic investments, and that its reliability will get worse if no strategic investments are approved.

Q. Are there additional factors besides tree trimming that potentially explain DTE Electric's poor reliability?

A. The Figure below is copied from DTE Electric's Distribution Grid Plan.[25]

[25] Exhibit A-23, Schedule M1, p. 126.



This Figure strongly suggests that DTE Electric could reach performance comparable to peer utilities by reducing tree/wind outages. There is little evidence in DTE Electric's distribution plan nor in testimony in this case that there is any other cause of DTE Electric's poor reliability performance than historically deficient tree trimming, and ample evidence that their historical tree-trimming cycle length was substantially longer than best practices.

Q. Hasn't DTE Electric made the observation that much of the equipment in its distribution system is older than the expected life of that equipment?

A. Yes. In Exhibit A-23, the 8th chapter addresses "asset health", and much of the analysis in that chapter actually concerns asset age. The Figure within the Distribution Grid Plan (Exhibit A-23, Schedule M1, page 160) that is labeled as Exhibit 8.1 presents DTE Electric average age and life expectancy for the major classes of distribution system assets. [26] The

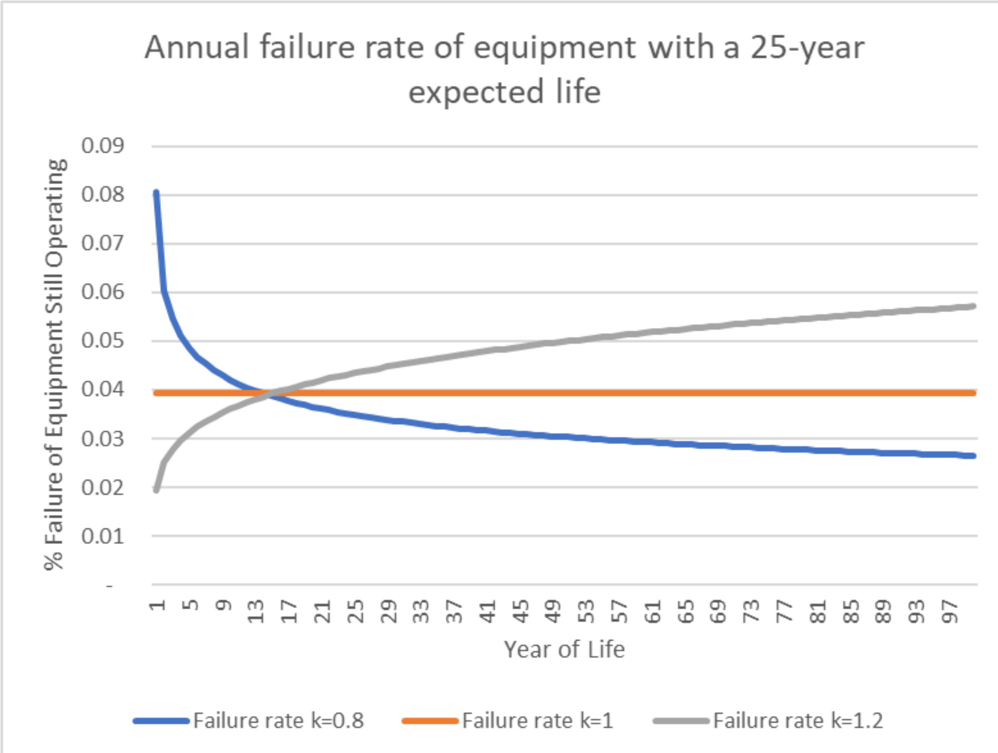
[26] This figure is reproduced as Table 5 on page 15 of the Direct Testimony of Ms. Pfeuffer.

narrative within this chapter discusses this comparison for each asset class or references the percentage of an asset class that exceeds life expectancy.

Q. Does the age of DTE Electric's distribution equipment indicate a need for escalated spending for replacement in order to improve reliability?

A. No. Life expectancy is the average age at retirement (replacement) due to failure (death) and not the maximum life of a piece of equipment. Average age of the equipment in use is conceptually different. There is a mathematical relationship between the two that depends on the shape of the survival curve for the asset category.

In reliability theory, it is common to use a family of life-length distributions called the Weibull distribution to statistically fit and analytically examine reliability engineering questions. The Weibull distribution is used because it has parameters that can depict a variety of patterns of life-length or failure rates. One of those parameters, commonly called the "shape parameter" of the Weibull distribution and denoted k, determines whether failure rates increase, decrease or stay the same with age. For illustration in this testimony, I will use values of 0.8, 1.0, and 1.2 for the Weibull shape parameter. Throughout, I will assume an expected life of 25 years. If represented by the age-specific failure rate, which specified the percentage of the devices still in use at a given age that will fail at that age, these three values of the Weibull shape parameter produce the following shapes:



As is obvious from this graph, when the shape parameter is 1.0, the failure rate is constant and used equipment is as reliable as used equipment. For a shape parameter less than 1.0, failure rate is high early in life and then declines. For a shape parameter greater than 1.0, failure rate starts low and increases. The following table illustrates that a comparison of average age of equipment in use to expected life or a statement of the percentage of equipment in use that exceeds expected life means little about the condition of the equipment in use. When new equipment has a high failure rate and failure rate declines with age (k=0.8) so that old equipment is better than new, the average age of the equipment in use will exceed expected life. When new equipment and used equipment have the same failure rate (k=1.0), average age of equipment in use will equal expected life. When new equipment has a low failure rate and old equipment fails at a higher rate (k=1.2) than new equipment, average in use will be lower than expected life. Thus, a high age of equipment in use may mean that old equipment is better than new rather than the equipment in use is old and decrepit. Notably, the proportion of equipment in use that is older than expected life is significant.

	Expected Life	Average Age in Use	% Older than 25
k=0.5	25	30.7	33%
k=1.0	25	25.0	37%
k=2.0	25	21.3	39%

The purpose of this illustration is simply to establish that neither the average age of equipment in use as compared to expected life nor the percentage whose age is greater than expected life are necessarily meaningful as to equipment condition.

Additionally, it is important to note that equipment failure rates are likely to be heterogenous across DTE Electric's distribution system. Conductors in locations without trees will likely last longer than conductors that are frequently broken by trees and spliced together. Transformers that are always lightly loaded will last longer than transformers that are frequently heavily loaded.

Q. What should the Commission infer about the most cost-effective strategy to improve reliability to the extent that outages are caused by equipment failure?

A. The Commission should focus on condition-based equipment replacement supported by good monitoring and inspection. In other words, the Commission should expect DTE Electric to focus on being smart about equipment replacement rather than focusing on equipment age. My colleague, Mr. Ozar, makes some specific recommendations in this regard.

Q. What should be the Commission's overall approach to improving DTE Electric's distribution reliability performance in this case?

A. The Commission should be supportive of tree-trimming to improve reliability. The Commission should require support for the cost-effectiveness of other investments in the distribution system, particularly capital investments, so as to carefully balance reliability improvements with affordability of electricity for residential customers. In particular, the Commission may instruct the utility to provide a glidepath towards specific reliability improvements associated with its tree trimming program decoupled from its equipment replacement programs and proposed strategic distribution system investments aimed at improving reliability, along with the costs of these proposed investments. To allow the Commission and stakeholders to evaluate the reasonableness and cost-effectiveness of these proposed investments, the Company should also provide historic and projected reliability and cost data for each component of its distribution strategy.

V. DISTRIBUTION SYSTEM PLANNING

Q. What is the role of distribution system planning in this case?

A. Much of the increased revenue requested by DTE Electric in this case supports spending presented in DTE Electric's Distribution Grid Plan.[27] The current version of the Distribution Grid Plan is provided as Exhibit A-23.

Q. What is your overall assessment of DTE Electric's Distribution Grid Plan?

A. The current plan is improved over the previous version, but needs further improvement. Although the plan is presented in this case and is therefore theoretically subject to

[27] See Direct Testimony of S.G. Pfeuffer.

examination in this case, the strictures of a rate case schedule with numerous other issues to address does not lend itself to the level of examination that is warranted by a plan that potentially drives billions of dollars of expenditure and is driving residential rate increases well above the increases for most other utilities. I again urge the Commission to consider a contested case for review of each Distribution System Plan and note that the Commission has been comfortable considering depreciation rates in that fashion despite a lack of specific statutory provisions for a separate depreciation case.

Q. Please summarize the major elements of the Distribution Grid Plan.

A. The plan describes DTE Electric's stakeholder engagement with respect to the plan, its perspective on the process of grid modernization, its distribution planning process, and approach to benefit-cost analysis. It then provides an overview of DTE Electric's distribution system an assessment of the health of the assets within the distribution system, and its proposals for distribution system hardening and resilience, tree-trimming program, infrastructure redesign and modernization, and technology and automation. Finally, it summarizes proposed capital and maintenance costs, approaches to performance-based ratemaking, and enablers of the plan as well as key next steps.

Q. About which of these are you testifying in this case?

A. Absence of testimony on other aspects of the plan does not reflect that I think these are unimportant or are not susceptible to challenge or improvement. Rather, I want to highlight some key points for the Commission's consideration in a case that is already large and complex in other respects. Specifically, I bring to the Commission's attention issues regarding the importance of:

- consideration of equitable reliability in prioritizing DTE Electric's distribution system spending;
- developing an approach to managing EV charging that will schedule charging in consideration of local distribution system considerations and incorporate opportunities provided by vehicle-to-home technologies;
- replacing DTE's assessment of asset health based largely on age statistics with one more thoroughly based in reliability and repair theory;
- optimization of monitoring and inspection programs to support equipment replacement based on conditions indicating incipient failure;
- local load data and forecasts;
- a reexamination of distribution system cost allocation based on engineering practices, with a particular focus on the allocation of costs by time; and
- inclusion of rate impact for each category of spending and for the plan as a whole.

I will conclude that the Commission should ask for another update of the Distribution Grid Plan by approximately September 2023 that incorporates key improvements in the plan.

Q. Please explain why and how DTE Electric should address consideration of equitable reliability in prioritizing its distribution system spending.

A. When a residential customer experiences a power outage of any material duration, they are likely to experience a loss of the ability to perform essential life functions and/or experience discomfort in their home. If the outage is not too widespread, they may be able to relocate to restaurants, hotels, homes of friends or relatives, or other temporary housing locations for the duration of the outage – but likely at some expense. They are also likely to experience losses of refrigerated food, medicines, or other purchased goods. In some cases, they may lose the use of life-supporting medical equipment. If the household has savings or credit, they can cover these expenses during the outage and spread the effects financial effects over a long period of time. If the household is low-income and lacks savings or credit, they may not be able to mitigate the effects of the outage and will instead suffer greater hardship. Under the standard assumptions of economics, people with means will spend for mitigation if and only if the financial costs are less than their valuation of the mitigated hardship. Evaluations of the cost of outages typically focus on this mitigative spending. For households that are cash-flow constrained, their value of mitigating hardship likely exceeds their means and their mitigating spending is not a good measure of the cost of the outage. As a result, harm to low-income households due to power outages tends to be undervalued. Nor should the Commission or DTE view the unmitigated hardships attendant on an outage as equivalent to the financial costs of mitigating an outage, since those hardships may include harms to health and safety, hunger, and considerable discomfort. For these reasons, DTE Electric should be prioritizing the reduction of outage harms in places where there are concentrations of low-income households.

DTE Electric acknowledges this consideration in their Distribution Grid Plan, Section 2.2.[28] In that section, DTE Electric states their intent to develop a system-wide analysis and map by Fall of 2021. Unfortunately, because their plan had been to make use of the Michigan Environmental Justice Screening Tool[29] for that analysis, and it was not available timely, that analysis has not been completed. DTE Electric also discusses this consideration in its identification of Key Next Steps, where DTE Electric stated their intent to incorporate

[28] Exhibit A-23, Schedule M1, pp. 34-37 of 568.

[29] https://www.michigan.gov/egle/maps-data/miejscreen.

this information into its Global Prioritization Model ("GPM").[30] The Commission should state its support for DTE Electric's plans in this regard and urge DTE Electric to complete that work as soon as is practicable.

Q. Please explain why and how DTE Electric should address developing an approach to managing EV charging that will schedule charging in consideration of local distribution system considerations and incorporate opportunities provided by vehicle-to-home technologies.

A. The Distribution Grid Plan proposes that DTE Electric will increase the capacity of the distribution system, particularly by increasing voltage in large portions of its distribution system from 4.8 kV to 13.2 kV[31] and perhaps even higher.[32] In significant part, this strategy is driven by expectations of increasing load due to transportation electrification. Additionally, DTE Electric considered a scenario of increased distributed resources including behind-the-meter solar and storage.[33] DTE Electric also is considering grid automation for various reasons.[34] Meanwhile, a number of automobile manufacturers have announced electric vehicles that are capable of vehicle-to-home bidirectional power flow. The large amount of storage that will become available as a result of EV adoption with significant products capable of bidirectional power flow suggests that distribution system plans should include an analysis and potentially be changed to reflect the opportunities to

[30] Exhibit A-23, Schedule M1, p. 490 of 568.

[31] Exhibit A-23, Schedule M1, Section 11.3.

[32] Exhibit A-23, Schedule M1, p 489 of 568.

[33] Exhibit A-23, Schedule M1, Section 3.3.

[34] Exhibit A-23, Schedule M1, Section 12.

use managed charging to avoid distribution system constraints and to both account for and potentially take advantage of vehicle-to-home bidirectional power flows.

The Commission should consider requiring such analysis from DTE Electric in their next Distribution Grid Plan and should consider directing Commission staff to convene stakeholders to examine this possibility and make recommendations to the Commission regarding general policy and expectations of utilities.

Q. Please explain why and how DTE Electric should base its assessment of asset health based in reliability and repair theory and not on equipment age.

A. As I showed earlier in this testimony, simple statistics like average age of equipment compared to expected life or percentage of equipment older than expected life are poor indicators of the need to replace equipment. Neither average age in use that exceeds expected life nor a significant percentage of equipment older than expected life demonstrates that DTE Electric's system or components are in need of accelerated replacement. But, in its Distribution Grid Plan, DTE uses such statistics to justify billions of dollars of planned expenditures.

An approach more tightly tied to equipment survival and replacement processes should provide much more accurate estimates of current needs for equipment replacement. Rather that citing age of equipment, it is necessary to look at the failure rates of equipment based on its condition and to forecast repair and replacement activity based on expected failure rates and inspection protocols. DTE Electric's depreciation cases provide detailed analysis of the life tables for each major category of distribution system assets. It would be a straightforward matter to use that analysis to identify the expected current rate of equipment retirement and replacement based on historical replacement practices.

Against the backdrop of current repair and replacement practices, DTE Electric can propose changes in practices and explain the effects on retirement and replacement rates in the full equipment survival distribution, resulting in an appropriate adjustment to depreciation rates, spending plans, and effects on reliability.

Q. Please explain how and why DTE Electric should optimize monitoring and inspection programs to support equipment replacement based on conditions indicating incipient failure.

A. One approach to repair policy is to institute repairs when things fail. This approach maximizes the life of each asset, but also causes outages unless there are parallel redundancies in the system. Replacement based on age, for assets that have distinctively worse reliability for older than newer assets can reduce outages, provided that replacement before failure does not cause as long an outage as replacement upon failure. However, for most types of equipment it is at least theoretically possible to examine or test the equipment and detect conditions that lead to likely near-term failure; when this is practical, optimal repair policy may be to replace equipment based on its condition through either periodic or ongoing monitoring or inspection programs.

Optimal monitoring and repair programs occur when the marginal cost of increasing inspection frequency and rigor or replacement criteria just offsets the reduced cost of outages. In effect, by increasing the frequency of inspection, DTE Electric can detect more incipient failures before actual failure and replace based on that incipient failure; on the other hand, inspection has a cost and that cost increases with increasing frequency. However, even though inspection may be costly, a system of inspection and repair or replacement will often be more cost-effective than replacing components just because they are old. The Commission should expect that DTE Electric optimizes inspection frequency and criteria to most cost-effectively achieve adequate reliability.

My colleague Rob Ozar addresses aspects of the Company's monitoring and inspection program for certain aspects of the distribution system, particularly poles and pole tops, and recommends additional monitoring opportunities to identify incipient equipment failures. The Commission should direct DTE Electric to demonstrate in its next rate case or in its next Distribution Grid Plan that its monitoring and inspection programs – frequency, specifications, tracking, and prioritization are optimized relative to the costs of repair or replacement upon failure or replacement based on age, for each category of distribution system assets (substations, conductors, and underground equipment, in addition to poles and pole tops).

Q. Please explain the importance of local load data and forecasts in DTE Electric's distribution system planning.

A. Essentially all distribution system spending is local in the sense that the infrastructure elements in the distribution system serve small areas. Consequently, the capacity requirements are local. Timely, cost-effective distribution system investments require knowledge of both current and forecast load by location. DTE Electric acknowledges this need and describes their intent to address in the Distribution Grid Plan.[35] However, at this time, they apparently do not have such data about current load, let alone forecasts.[36] The most cost-effective strategy for upgrading capacity will generally be to wait until a need is forecast in the short-term and then upgrade to meet long-term capacity requirements. Both

[35] Exhibit A-23, Schedule M1, Section 12.9.4.4 and pp. 487-488 of 568.

[36] Exhibit MEC-10.

the timing of upgrades based on short-term need and the long-term capacity requirements require local forecasts. If DTE is to execute an upgrade strategy that is cost-effective but also does not materially constrain a transition to electric transportation, electric heat, and distributed resources it is essential that it have an ability to adequately forecast loads.

DTE Electric has recognized this need and articulated a reasonable plan to address it. The Commission should support that portion of DTE Electric's plan that addresses the need for data and forecasts but also be wary of major investments that are premature due to lack of supporting forecasts.

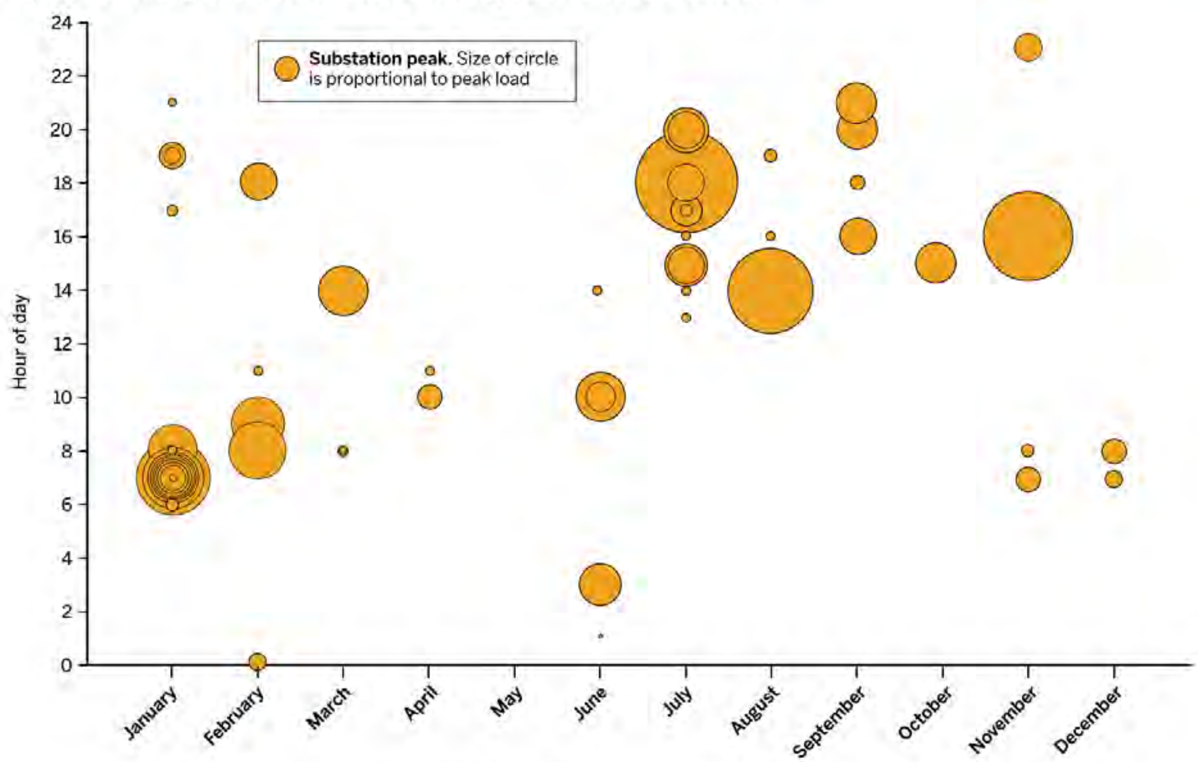
Q. Please explain why and how DTE Electric should reexamine its distribution system cost allocation based on engineering practices, with a particular focus on the allocation of costs by time.

A. In this case, DTE Electric allocates most plant-related distribution system costs based on class contribution to annual peak load on a voltage-level basis. However, because of the local nature of distribution system demand and capacity, it is not appropriate to base cost allocation on contribution to peak demand unless it is demonstrated that local peaks are highly correlated. In this case, I sought to examine the relationship between load profiles between different portions of DTE Electric's distribution systems by looking at the highest level of aggregation within the distribution system – circuits as measured at substations – which would be the most correlated to overall system peak. DTE was unable or unwilling to provide that information.[37]

[37] Exhibit MEC-10.

The following graph[38] illustrates the diversity of substation peak timing for another utility:

Figure 41. Month and hour of Delmarva Power & Light substation peaks in 2014



Source: Delmarva Power & Light. (2016, August 15). Response to the Office of the People's Counsel data request 5-11, Attachment D. Maryland Public Service Commission Case No. 9424

DTE Electric also has 3239 low-voltage distribution circuits[39] emanating from its substations, which again are very likely to have diverse load profiles based on both differences in customer mix and location and also on simple randomness. Most of those circuits have branches with variations of load profile amongst those branches such that the timing of peak load on circuit elements will not be coincident. Cost allocation should therefore be based on an understanding of the timing and contributions of customer classes to local demand on substations and circuits and perhaps at lower levels of the distribution

[38] Obtained from Lazar, J., P. Chernick, and W. Marcus. 2020 Electric Cost Allocation for a New Era: A Manual. Regulatory Assistance Project.

[39] Pfeuffer Direct, SGP-13, Table 4.

system. I therefore recommend that the Commission require DTE Electric to file 8760-hour load profiles for each of its distribution substations and/or circuits as supplementary data in its next rate case, and to examine distribution system cost causation in its next Distribution Grid Plan.

Q. Please explain why and how DTE Electric should include the rate impact of each category of spending and for the plan as a whole.

A. DTE Electric's Distribution Grid Plan purports to characterize needed spending on its distribution system. However, these include capital investments in equipment of quite varying depreciation rates and operations and maintenance expenses. The Commission and other stakeholders cannot fully assess all proposed spending on a comparable basis without adjusting for the different time periods over which cost recovery will occur. The most relevant representation of proposed spending is to present all elements of the plan with illustrative required revenue calculations and to display the effects on customers through the impacts on rates. While actual determination of rates is properly reserved for rate cases, presentation of rate impacts in the Distribution Grid Plan will aid rational examination of the Plan. These calculations can be done using the depreciation rates, return on capital, and cost allocation practices most recently approved by the Commission.

Q. Why and when do you recommend that the Commission require DTE Electric to present a revised Distribution Grid Plan?

A. There is an old aphorism "measure twice and cut once" that is relevant in this matter. Distribution system spending has increased significantly in recent years and DTE Electric is proposing substantial further increases in this case and in the future. This spending is driving substantial increases in residential and secondary commercial rates when both of those are already high compared to peer utilities. The Commission should therefore pursue the most cost-effective approach to DTE Electric's distribution system spending. Cost-effectiveness will come largely from good planning and performance incentives. The current Distribution Grid Plan is better, but still not what the Commission should seek. Distribution system spending is on a similar scale as production spending, but the current distribution plans are still far less rigorous than the integrated resource plans through which the Commission examines production spending. It is therefore appropriate that the Commission direct DTE Electric (and other utilities) to proceed to a next round of distribution system planning and direct them to provide a specific set of improvements to the existing plans. Assuming that Distribution System Planning is an ongoing process at DTE Electric and allowing approximately nine months for response to any guidance the Commission may have leads to filing such an update in approximately September 2023.

VI. ELECTRIC VEHICLE CHARGING INFRASTRUCTURE

Q. Please summarize DTE Electric's proposals in this case regarding Electric Vehicle ("EV") charging infrastructure.

A. DTE Electric proposes to continue its EV charging pilot program, which it brands as "Charging Forward," with some modifications and several additions. These are presented in the testimony of B. J. H. Burns.[40] DTE Electric will continue the eFleets program through 2025 as approved by the Commission in Case No. U-20935.[41]

DTE Electric proposes to continue, with some modifications, the Customer Outreach & Education, Residential Smart Charger Support ("Residential Rebates"), Bring Your Own

[40] Direct Testimony of B. J. H. Burns, BJHB-4:15 through BJHB-85:3.

[41] *Id.* at BJHB-10:4 through BJHB-14:13.

Charger, EV-Ready Builder Rebates, and Charging Infrastructure Enablement ("Make-Ready Rebates") activities of the Charging Forward pilot program.[42] DTE Electric also proposes to add to the Charging Forward pilot Residential Charging as a Service ("CaaS"), Charging Hubs, Transit Batteries, Transportation Network Company ("TNC") Driver Rebates, Income-Eligible Rebates, Commercial CaaS, and an Emerging Technology Fund.[43] All of these elements would continue through 2025.

In addition to requesting approval to extend the Charging Forward pilot program, DTE Electric seeks approval to continue to defer customer rebates and program operations and maintenance costs in the fashion already approved by the Commission[44], including applying those practices to the newly proposed elements of the program.[45]

Q. What modifications does DTE Electric propose to the existing activities of the Charging Forward pilot program?

A. With respect to Customer Outreach & Education, DTE Electric mostly proposes to continue current practices, but will ramp up in-person EV experiences, add EV capability to a DTE-wide rate tool that assists customers to select the TOU rate that is best for them individually, and potentially extend DTE Electric's Virtual EV Showroom to provide information about dealer inventory.[46]

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[42] *Id.* at BJHB-14:18-22.

[43] *Id.* at BJHB-14:22-BJHB-15:2.

[44] See, e.g., Case No. U-20697, December 17, 2020, Order, p. 240; Case No. U-20162, May 2, 2019, Order, pp. 114-15; and Case No. U-20134, January 9, 2019, Order, p. 9.

[45] Direct Testimony of T. M. Uzenski, TMU-85:25 through TMU-86:10.

[46] Burns Direct, BJHB-28:21 through BJHB-29:5.

With respect to support for residential Level 2 charging, DTE Electric proposes to modify its offer of a $500 rebate for a residential Level 2 charger to allow customers to use a charger of their choice rather than selecting from a limited list maintained by DTE.[47] DTE Electric does not propose any changes in its Bring Your Own Charger or EV-Ready Builder Rebates programs.

With respect to commercial charging, DTE Electric proposes to reduce Level 2 charger rebates from $2500 per port to $2000 per port.[48] Charging Infrastructure Enablement practices would not change.

Q. Do you support continuation of the existing Charging Forward elements with the modifications proposed by DTE Electric?

A. Yes, with certain caveats.

First, the DCFC make-ready and rebate programs should be modified to ensure that make-ready infrastructure is capable of supporting 350 kW DCFCs and DCFC rebates should require that the DCFCs should support at least 150 kW charging rates. DTE Electric has, properly, thus far administered the DCFC rebates as a joint program with the State of Michigan's Charge Up Michigan program.[49] That program has been developed based on recommended DCFC locations developed from their Optimized EV Charger Placement Plan,[50] which found that 150 kW DCFCs provide the necessary level of charging services

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[47] *Id.* at BJHB-31:19-21.

[48] *Id.* at BJHB-42:5-18.

[49] See https://www.michigan.gov/egle/about/organization/materials-management/energy/rfps-loans/charge-up-michigan-program?msclkid=97f22adecf1211ec8de9568951d42288

[50] See https://www.michigan.gov/egle/about/organization/Materials-Management/energy/Transportation/optimized-ev-charger-placement-plan

at lower cost than with lower-rated DCFCs. The reason this happens is that the shorter charging times associated with higher charging rates provides a given charging service level with fewer charging ports, hence at lower cost. It also provides better customer service, reducing both charging time for each customer and queuing time waiting for a charging port to become available. Additionally, the Federal Highway Administration's guidance for the National EV Infrastructure Program proposes that 150 kW be the minimum per-port charging rate and 600 kW the minimum infrastructure capacity for use of Federal funds to provide fast-charging infrastructure.[51] Most new EV models support charging rates of approximately 150 kW.

Second, I am concerned that the scale of the Charing Forward program proposed by DTE Electric is insufficient to meet EV charging infrastructure needs in its service territory through 2025. For that reason, I recommend below that the Commission direct DTE Electric to propose a permanent program within approximately four months of the conclusion of this case, by March 15, 2023, notwithstanding the proposed duration of the extended Charging Forward pilot through 2025. I also recommend that the Commission authorize spending the make-ready investments and customer rebates faster than the schedule proposed by DTE Electric in this case, if customer demand warrants.

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[51] National Electric Vehicle Infrastructure Formula Program, Program Guidance. Federal Highway Administration. February 10, 2022, p 26, Available from https://www.fhwa.dot.gov/environment/alternative_fuel_corridors/nominations/90d_nevi_formula_program_guidance.pdf

Q. Please summarize DTE Electric's proposed new activities in the extended Charging Forward pilot?

A. DTE Electric proposes to add Residential Charging as a Service ("CaaS") to its residential EV charging activities. This activity will offer residential customers a turn-key installation and financing program for residential EV chargers, the costs of which will be recovered from the participating customers.[52]

DTE proposes to try a concept they describe as Charging Hubs. DTE would build, own, operate, and maintain sites with several high-powered DCFCs, that would be intended to serve multiple medium-duty and heavy-duty fleets as those fleet owners pilot vehicle electrification.[53]

DTE Electric also proposes a new Transit Batteries program, under which DTE Electric would purchase the battery when a transit agency purchases an electric bus, which would lower the initial purchase price of an electric bus, and then recover the costs of the battery from the transit agency through monthly charges. The battery would be owned by DTE Electric until the costs are recovered, upon which ownership would transfer to the transit agency; the transit agency could choose to return the battery to DTE Electric which anticipates then using the battery for grid support.[54]

DTE Electric proposes a pilot effort to support EV adoption by TNC drivers, in non-exclusive partnership with Lyft and will work with other TNCs if the program is approved.

[52] Direct testimony of B. J. H. Burns, BJHB-34:4 through BJHB-37:11.

[53] *Id.* at BJHB-42:25 through BJHB-46:25.

[54] *Id.* at BJHB-47:2 through BJHB-51:7.

This program will offer a $5,000 rebate for the purchase of a vehicle that meets the partnering TNC's requirements[55]

DTE Electric also proposes to offer $1500 residential customer rebates to people who lease or purchase a new or used EV with a total price less than $50,000 provided that the person is part of a household that qualifies for income-based public assistance programs or has annual income less than 400% of the Federal Poverty Line. DTE Electric will seek to offset costs of this program partly through voluntary contributions, an approach similar to the MIGreenPower Low-Income Donation Pilot established in Case No. U-20713. [56]

DTE Electric additionally proposes a Commercial Charger as a Service ("CaaS"). In this program, DTE would install commercial chargers, fund and own the electrical infrastructure up to the chargers, and recover costs of the chargers from the site host through a monthly charge on the electricity bill. This offer would only be available in Environmental Justice communities, multiple unit dwellings that provide affordable housing or housing for vulnerable persons, rural areas, and where a municipality is the site host.[57]

Finally, DTE Electric proposes an Emerging Technology Fund which would allow it to act rapidly to test new technologies, support economic development, and prepare for widespread EV deployment by undertaking demonstration projects.[58]

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[55] *Id.* at BJHB-57:11 through BJHB-60:5.

[56] *Id.* at BJHB-60:7 through BJHB-64:16.

[57] *Id.* at BJHB-64:18 through BJHB-68:8.

[58] *Id.* at BJHB-69:17 through BHJB-71:11.

Q. Do you support these new elements of the Charging Forward pilot?

A. I am generally supportive of DTE Electric's efforts to further advance transportation electrification and therefore support DTE Electric's proposals with certain reservations. I address each program in turn.

First, with respect to the proposed Residential CaaS program, the Company is appropriately targeting a critical market segment. Home charging is a virtual necessity for mainstream PEV buyers," according to the National Academies of Science in a comprehensive report on this subject.[59] The Residential CaaS would add a valuable new option to the Company's residential portfolio, providing turn-key solution for customers who prefer not to research charging stations and oversee installation, or are constrained by the upfront cost of charging equipment. In Minnesota, New Mexico, and Colorado, regulators have approved similar turn-key options together with up-front rebate and bring-your-own-charger programs like DTE's past and current residential offerings.[60]

Homes are where vehicles are parked for the most hours of the day, making them the most convenient place to charge, especially overnight when people are sleeping and there is

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[59] National Research Council of the National Academies of Sciences, *Overcoming Barriers to the Deployment of Plug-in Electric Vehicles*, THE NATIONAL ACADEMIES PRESS (2015), p. 83.

[60] Order Approving Electric Vehicle Home Service and Voluntary Electric Vehicle Charger Service Programs as Modified at 14-15, Docket 19-559, Minnesota Public Utilities Commission (approving a customer-provided charger program and an "EV Home Service" program akin to DTE's residential CaaS program proposal); Commission Decision Granting Application with Modifications at 64 (December 23, 2020), Proceeding No. 20A-0204E, Colorado Public Utilities Commission (approving for Public Service Company of Colorado a Transportation Electrification Plan with a residential portfolio including a "Standard Home Wiring Rebate for Level 2 charging equipment," an "Income-Qualified Rebate for wiring and chargers [], as well as the Home Charging Service program."); Final Order Adopting Recommended Decision with Modifications, Case No. 20-00150-UT, New Mexico Public Regulatory Commission (approving for Southwestern Public Service a Transportation Electrification Plan with a residential portfolio including a home wiring rebate, an income-qualified rebate, and a home charging service program).

plenty of spare capacity in the grid. Despite that grid integration potential, DTE proposes that it will not require the participants in the Residential CaaS program to select a time of use rate—unlike the standard residential rebate—on the grounds that the customer is not receiving a rebate but is fully paying for the charger. Notwithstanding that the customer is ultimately paying for this charging infrastructure, it remains important that charging times be shaped to minimize use of production and distribution capacity at peak times to minimize costs driven by EV charging. DTE Electric has shown that its BYOC program is effective in reducing peak period charging.[61] And the Company phased out its $500 rebate program because "the time-of-use (TOU) enrollment is more critical [than the rebate] to ensure EV load benefits accrue directly to all customers…."[62]. I therefore recommend that participants in the residential CaaS program be required to choose between a time of use tariff and participation in the BYOC program.

Second, the Charging Hubs proposal would help fleet operators surmount a key barrier to transitioning their vehicles to electric technologies: the cost of charging infrastructure. DTE's program focuses support on those fleet operators for whom this challenge is acute because the operators lack the physical space, time, or capital to make a wholesale transition to electric vehicles and wish instead to transition a small number of fleet vehicles.

DTE has proposed to locate Charging Hubs according to certain criteria.[63] In response to discovery questions, DTE Electric was unable or unwilling to identify the locations within

[61] Burns Direct, BJHB-22:17-22.

[62] DTE Charging Forward March 21, 2022 Stakeholder Meeting Presentation, Slide 20.

[63] Burns Direct, BJHB-45:8-22.

its service territory that would meet those criteria.[64] In effect, DTE responded to a request to identify locations meeting any other criteria by saying that DTE Electric had not yet identified locations meeting their first criterion, "locations with sufficient DTE system capacity" so could not identify such locations that also meet the other named criteria. At the same time, DTE claimed in testimony that "DTE is uniquely suited to site Charging Hubs where there is both sufficient power supply and customer demand. Because DTE can identify ideal locations on its system, it can deploy Charging Hubs at a minimum total cost."[65] DTE Electric either does not have this unique qualification to site Charging Hubs or is withholding that information to gain a competitive advantage in implementing this idea. More generally, as EV population increases and the need for DCFCs increases, it will increasingly be important for DCFC providers to be able to determine good locations. A process whereby DCFC developers must guess at good locations and ask DTE for interconnection studies to determine whether there is adequate transmission and distribution capacity will be inefficient and delay the development of adequate infrastructure. The Commission should order DTE to provide online charging capacity maps of its system to address this need. Such a capability will also be useful for commercial and industrial land development since those loads often have needs reasonably similar to the needs of DCFCs. If the Commission approves this element of DTE Electric's Charging Forward proposal in this case, the Commission should also make clear that such approval is only for this limited pilot and that DTE Electric is expected to facilitate similar developments by other parties, by providing access to the necessary information about DTE

[64] Exhibit MEC-7.

[65] Burns Direct, BJHB-44:14-16.

Electric's systems and by offering make-ready and rebates for such developments through its other pilot or future permanent programs.

Third, I strongly support the proposed Transit Batteries program. Electric transit buses are market-ready and commercially available.[66] Greater access to electric buses would improve access to clean transportation options for all DTE customers. The fuel cost savings and lower maintenance costs associated with electric buses make them more cost-effective on a total cost of ownership (TCO) basis than fossil-burning technologies, and the resulting savings can be reinvested into additional clean vehicle purchases, creating a positive economic cycle. This virtuous cycle improves as battery and vehicle costs fall, which is occurring rapidly; battery costs have decreased by 89 percent over the past ten years and have fallen 6 percent in the past year alone.[67] DTE's Transit Batteries program would help agencies overcome the higher up-front capital requirements of an electric bus, allowing a transit agency to then lock in the lower lifetime costs of electric buses. Using the battery for "second-life" grid applications is consistent with the Commission's guidance that customer-funded EV programs prioritize "load management," and "new technology."[68]

Finally, I generally support DTE's proposed EV rebates for TNC drivers and residential customers because the program is intended to be accessible to lower-income households and promote equitable access to clean transportation. EV purchase incentives are very

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[66] Lowell & Culkin, *Medium- And Heavy-Duty Vehicles: Market Structure, Environmental Impact & EV Readiness* at 20 MJ Bradley & Associates (July 2021) ("In the case of Transit buses every bus manufacturer that sells diesel buses in North America also offers an electric version; in addition, there are two electric-only manufacturers that have already made a large number of sales.").

[67] *Battery Pack Prices Fall to an Average of $132/kWh, But Rising Commodity Prices Start to Bite*, Bloomberg New Energy Finance (November 30, 2021), *available at* https://about.bnef.com/blog/battery-pack-prices-fall-to-an-average-of-132-kwh-but-rising-commodity-prices-start-to-bite/.

[68] Case No. U-18368, December 20, 2017, Order Adopting Guiding Principles, p. 35.

effective, but many incentive programs have primarily benefited wealthier customers because they either rely on a high tax liability (in the case of tax rebates), effectively demand high income (for rebates that require the customer to pay up front), or require purchase of only new vehicles. DTE's proposal partially improves on those issues because it is a direct, income-qualified[69] incentive that can be used for new and used vehicles, similar to EV incentive programs approved by the Colorado and Nevada utility commissions.[70] DTE's program would also fill a critical gap for qualifying customers, because Michigan lacks a statewide EV purchase incentive. While innovative and thoughtful, these programs could be improved in two ways. First, the vehicle rebates should be available on a point-of-sale basis in order to truly support an opportunity for income-qualified customers to purchase EVs. A vehicle purchase presents challenges for income-qualified customers, and the challenge of delayed timing to receive a rebate should be avoided. With respect to DTE Electric's proposal to offset costs of its proposed low-income household vehicle rebate program through donations, I note that in this case DTE proposes an investment of $1.3 million to develop the capability to accept on-line donations for the MIGreenPower Low-Income Donation Pilot, without demonstrating an expectation of receiving sufficient donations to recover the costs of the on-line donation capability. There are numerous web sites designed to allow anyone to create a donation campaign at little

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[69] The residential customer program requires income qualification, and the TNC program effectively requires such qualification because full-time TNC drivers in many cases are low-to-moderate income individuals. *See, e.g.*, Benner et al., On-demand and on-the-edge: Ride hailing and Delivery workers in San Francisco (May 2020).

[70] Commission Decision Granting Application with Modifications at 33-34 (December 23, 2020), Proceeding No. 20A-0204E, Colorado Public Utilities Commission (approving a three-year, $5 million equity rebate program for Public Service Company of Colorado offering up-front rebates of $5,000 toward new vehicles and $3,000 toward used vehicles for income-qualified customers); Order at 4 and Attachment A at 4, Docket 22-02002, Public Utilities Commission of Nevada (approving NV Energy's "Lower Income EV Incentives Program" offering rebates of $2,500 per vehicle for qualified customers).

cost that could be used by DTE to seek such donations. It is unreasonable and imprudent to make such large investments in the capability to receive donations when almost the entire amount sought through donations could be funded with the proposed IT investment. I recommend that the Commission direct DTE Electric to undertake the proposed low-income vehicle rebate program without reliance on on-line donations.

Q. You indicated that you are concerned that the scale of the Charging Forward program proposed by DTE Electric in this case is insufficient. Please explain.

A. I am concerned that:

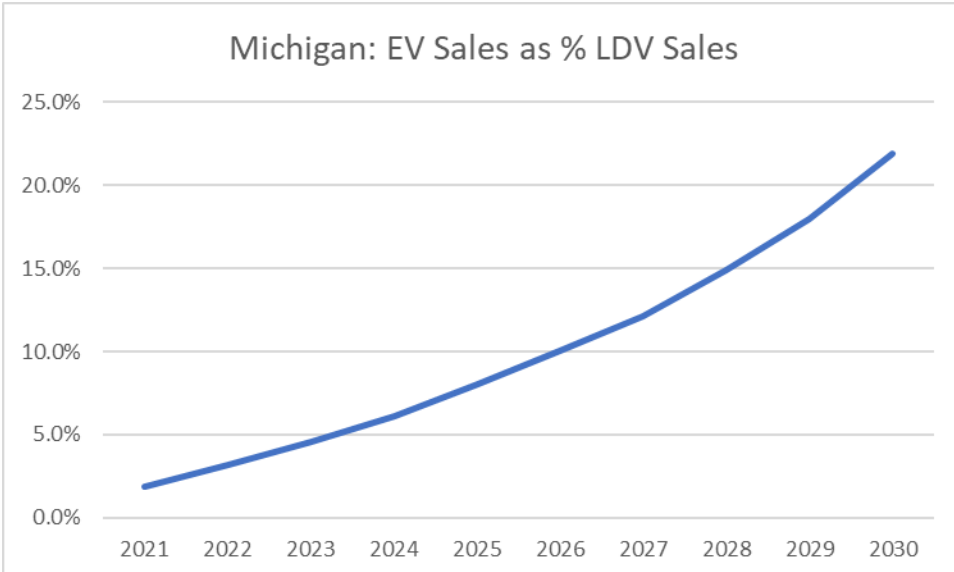
- the pace of EV adoption may be faster than projected by DTE Electric in this case;
- the EV infrastructure deployment projected by DTE Electric in this case will be insufficient even if EV adoption is consistent with DTE Electric's projections; and
- that opportunities to use federal programs to develop EV infrastructure in Michigan may be hampered by lack of matching funds.

Q. Why do you think that the pace of EV adoption may be faster than projected by DTE Electric in this case?

A. DTE Electric's projection of EV adoption is presented by B. J. H. Burns, particularly in his Figure 1.[71] Exhibit MEC-7 presents discovery responses from DTE Electric about this projection. As explained by DTE Electric in its discovery response, this projection was based on a simple average for Michigan of three forecasts, from Bloomberg New Energy Finance published in June 2021, from Automotive Communities Partnership published in June 2021, and from HIS Markit published in December 2019. Based on data provided by

[71] Burns Direct, BJHB-17:5-23.

DTE I its discovery response, I calculated DTE Electric's projected EV sales in Michigan as a percentage of light-duty vehicle sales, which are presented in the following graph.



There are several reasons to consider that this projection may be significantly low.

One of the forecasts averaged into this projection, by Bloomberg new Energy Finance shows much faster adoption, reaching approximately 34% EV sales of light-duty vehicle sales in 2030.

Since the projections that DTE Electric averaged were developed, Federal policy has shifted considerably; President Biden signed an Executive Order in August 2021 directing a tightening of Corporate Average Fuel Economy Standards, which were released in April 2022,[72] and a goal of 50% EV sales of light-duty vehicle sales by 2030. The Infrastructure Investment and Jobs Act ("IIJA"), signed by President Biden on November 15, 2021

[72] See USDOT Announces New Vehicle Fuel Economy Standards for Model Year 2024-2026 | US Department of Transportation, available from https://www.transportation.gov/briefing-room/usdot-announces-new-vehicle-fuel-economy-standards-model-year-2024-2026?msclkid=9c471e0ccf2a11ecb9b256b95b597fa0.

provided a number of substantial federal spending initiatives to accelerate the adoption of EVs. A number of automobile manufacturers have announced high goals for the electrification of their product lines.[73] Notably, these include General Motors which has stated intent to have an all-electric product portfolio by 2035 and Ford, which plans to reach 50% EV sales by 2030. To achieve these goals while selling each new model for 5-6 years in order to make the model profitable, these manufacturers must begin offering electrified models and discontinue development of internal combustion engine models within the next few years. This should produce a nearly linear increase in % EV sales of light-duty vehicles up to full electrification in 2035. This path will require that about 50% of light-duty sales in 2030 be electric, which is more than twice the EV sales percentage used in DTE Electric's forecast.

Meeting the state's climate goals would require even more ambitious action.[74] A 2022 report prepared by Synapse Energy Economics found that EVs must comprise nearly 100% of new cars sold in the state by 2035 to meet the state's climate goals.[75] This is also consistent with the Governor's MI Healthy Climate Plan, which set a goal for the state to

[73] Consumer Reports provides a good summary at https://www.consumerreports.org/hybrids-evs/why-electric-cars-may-soon-flood-the-us-market-a9006292675/?msclkid=d8c48a83cf2b11ecb59f61b07e48b8c2.

[74] In September 2020, Governor Whitmer issued Executive Directive 2020-10, which sets a goal of achieving statewide carbon neutrality by 2050. The directive also sets an intermediate goal of reducing economy-wide emissions 28 percent below 1990 levels by 2025.

[75] Synapse Energy Economics, Transforming Transportation in Michigan: A Roadmap to the State's 2050 Climate Target at 1, 8-9.

develop the charging infrastructure capable of supporting 2 million EVs by 2030, including at least 50% of light duty vehicles and 30% of heavy and medium-duty vehicles.[76]

I am not asserting that DTE Electric's projection is particularly wrong, as these projections are inherently uncertain. Rather, I am concerned that actual sales could be significantly higher than DTE forecast, which could result in inadequate charging infrastructure and failure to meet the state's climate goals. The Commission's authorization for DTE's EV charging infrastructure program should be responsive to EV sales.

Q. Why are you concerned that the EV infrastructure deployment projected by DTE Electric in this case will be insufficient even if EV adoption is consistent with DTE Electric's projections?

A. By its own admission, DTE Electric charging infrastructure plans fall short of likely infrastructure requirements based on their EV sales projection.[77]

Table 7. State of Charging Infrastructure in DTE Electric's Territory[48]

	Existing Ports	Needed by 2023 (52,000 EVs)	Estimated DTE Rebates[49]	Estimated Remaining Gap in 2023
Total Level 2[50]	620	6,000	750	4,630
DCFC	110	730	124	496

[76] MI Healthy Climate Plan, available from https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan.

[77] Burns Direct, BJHB-40, Table 7.

Q. **Why are you concerned that opportunities to use federal programs to develop EV infrastructure in Michigan may be hampered by lack of matching funds?**

A. The IIJA and some regular appropriations have provided considerable federal funds for transportation electrification. These have been usefully summarized as totaling more than $50 billion by Atlas EV Hub.[78] Exhibit MEC-8 shows that DTE Electric agrees that it may need to ramp up elements of the Charging Forward program as these federal programs develop.

At the same time, it is important to note that DTE's Charging Forward programs would be complementary to the National EV Infrastructure (NEVI) program, as funding under this specific program is directed to designated Alternative Fuel Corridors to build a national network of fast charging infrastructure. And, even if NEVI funding could be used for the critical home, workplace, or public charging infrastructure, the NEVI program is far too small to meet the infrastructure need in Michigan or nationwide. Research demonstrates the pace of charging infrastructure deployment needs to significantly accelerate to meet the needs of the growing EV market:

> To support electric vehicle growth through 2030, public and workplace chargers will need to increase 27% annually, which is less than the rate of charger growth between 2017 and 2020, but requires adding an average of over 200,000 chargers each year by 2026. This growing charging network would include 500,000 public chargers by around 2027, several years faster than the Biden administration's goal for 2030.[79]

And the charging infrastructure gap is even greater in the Midwest and South:

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[78] See https://www.atlasevhub.com/materials/invest-in-america-act-h-r-3684/.

[79] Gordon Bauer, Chih-Wei Hsu, Mike Nicholas, and Nic Lutsey, *Charging Up America: Assessing the Growing Need for U.S. Charging Infrastructure Through 2030*, International Council on Clean Transportation, July 2021, available at: https://theicct.org/publications/charging-up-america-jul2021.

> To meet projected EV growth, public and workplace charging infrastructure will need to grow at greater rates in many rural areas. Many regions across the Midwest and South with less infrastructure investment to date would need annual charger growth rates exceeding 50%, at least double the national average.[80]

The study cited above estimates that the investment needed to close the charging infrastructure gap by 2030 nationally is $28 billion.[81] Other researchers estimate $87 billion (including $39 billion for public fast charging) is needed by 2035 to grow the passenger EV market.[82] It is therefore critical that utility programs continue to provide critical matching funds to leverage these federal investments and to maximize the infrastructure deployment that will be needed in the state.

Q. How do you recommend that the Commission address your concern that the Charging Forward proposal in this case may not be sufficient?

A. As I indicated earlier in this testimony, I recommend that the Commission direct DTE Electric to submit a proposal to the Commission by around March 15, 2023 to establish a permanent EV charging infrastructure program. The Commission provided such direction to Consumers Energy in Case No. U-20963.[83]

I also recommend that the Commission make clear in its Order in this case that DTE Electric may accelerate the spending of funds authorized for the Charging Forward pilot program expansion if warranted by customer demand.

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[80] *Id.*

[81] *Id.*

[82] Atlas Public Policy, *U.S. Passenger Vehicle Electrification Infrastructure Assessment*, available at: https://atlaspolicy.com/rand/u-s-passenger-vehicle-electrification-infrastructure-assessment/.

[83] Case No. U-20963, December 22, 2021, Order, pp 311-12.

Q. Please describe how you recommend that a permanent EV charging infrastructure program be structured?

A. The most important feature of a permanent EV charging infrastructure program is that recoverable costs should not be subject to a basically fixed budget cap as is the case with Charging Forward. Rather, it should be responsive to EV adoption, so that if EV adoption proceeds faster than projected by DTE Electric, lack of EV charging infrastructure does not come to limit EV adoption.

A permanent EV charging infrastructure program should be structured so that non-participating customers are no worse off than if EV adoption was not occurring. This is similar to line extensions. Electricity consumption for EV charging will produce revenue to DTE. Some of that revenue must pay for incremental costs of EV charging and the balance of that revenue (which I will refer to as system-wide EV net revenue) can be used for additional investment to accelerate EV adoption or can contribute to DTE Electric's fixed costs and sunk costs, thereby diluting rates for non-participating customers. The Commission will need to formulate the division of net revenue between EV support and rate dilution based on evidence, and that division might appropriately evolve over time. In the near term, I recommend allocation primarily to EV support in furtherance of the MI Healthy Climate Plan.[84]

[84] https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbfffa&hash=99437BF2709B9B3471D16FC1EC692588.

Generally, if a residential customer acquires an electric vehicle at current levels of EV adoption, it is unlikely that distribution system upgrades will be required.[85] However, increasing adoption of EVs may require distribution system upgrades. If EVs are to become ubiquitous, it would be unjust to have some EV adopters able to do so without paying for distribution system upgrades and others paying substantially for distribution system upgrades because of the timing or location of their adoption. I therefore recommend that the Commission adopt a policy that all distribution system upgrades required for residential EV charging should be provided by DTE Electric without contribution in aid of construction ("CIAC") by the residential customer. The cost of those distribution system upgrades can be considered as a priority allocation of system-wide EV net revenue, though some care should be taken to avoid attributing costs of distribution upgrades driven by multiple causes to EV charging alone.

Because EV adoption requires that public charging infrastructure be available, it is appropriate to consider that net revenue from all charging, including charging at home, may be invested in supporting adequate public charging infrastructure. This justifies the practices within the Charging Forward pilot of providing distribution system upgrades, make-ready investments, and even rebates to create an essential network of charging locations. A portion of those costs would be provided under CIAC policy based on the net revenue expected from the public charging location itself. To facilitate future permanent program development, the Commission should expect that the calculation of CIAC requirements should be made for all commercial charging locations, public or private, and that allocations of system-wide EV net revenue to cover CIAC will be explicit and guided

[85] DTE Electric. 2020. Electric Vehicle – Grid Impact Study Summary Report, available from https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000CFdYoAAL.

by policy approved by the Commission. Waiver of CIAC and rebates for public charging, funded by system-wide EV net revenue likely should evolve as an essential charging network is completed; one indicator that public EV charging infrastructure warrants support from system-wide EV net revenue should be whether it is matched by public funds. The Commission should note that in this case DTE Electric represents that its screening of locations for such assistance has materially lowered the cost of the public charging infrastructure it has supported;[86] it would be appropriate that the Commission authorize continued screening of public charging locations along these lines.

To the extent that there is system-wide net revenue available beyond the costs outlined above, those funds may be used for continued pilot programs to expand transportation electrification or for investments in equitable transportation electrification outcomes.

Q. What other guidance should the Commission provide regarding a permanent program?

A. The Commission apparently found it very helpful that Consumers Energy had adopted a goal for EV adoption in its service territory.[87] Within the framework for a permanent program that I outlined above, the Commission should request that DTE Electric develop its specific proposals with a view toward achieving DTE Electric's share of the goal in the MI Healthy Climate Plan to provide EV charging infrastructure for 2 million EVs statewide by 2030.[88]

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[86] Burns Direct, BJHB-22:23 through BJHB-23:3.

[87] Case No. U-20963, December 22, 2021, pp. 311-312.

[88] MI Healthy Climate Plan, available from https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan.

To facilitate full analysis of net revenue from EV charging, I recommend that the Commission direct the Company in its next rate case and thereafter to include in its rate case filings an analysis of the net effects of EV adoption and charging in the Company's service territory. Such an analysis could follow a standard Exhibit as is done for other topics as directed by the Commission's rate case filing requirements. The required analysis should provide:

1) numbers of electric vehicles by class registered in the utility's service territory,

2) amounts of electricity delivered for EV charging by customer rate schedule where the charging occurs,

3) revenue from electricity delivered for EV charging by customer rate schedule where the charging occurs,

4) costs of power supply for EV charging by rate schedule,

5) gross margin from EV charging by rate schedule,

6) revenue requirements related to EV infrastructure and allocation of revenue requirements by customer rate schedule, and

7) net margin benefitting customers in each rate schedule.

VII. PLANT STUDY, CALCULATION OF CAPACITY CHARGES, AND GENERATION COST ALLOCATION

Q. Please explain the Plant Study in this case.

A. In Case No. U-20561, my colleagues and I undertook to examine production cost allocation in DTE Electric's cost of service study. As part of that analysis, we undertook to determine the revenue requirements for each of DTE Electric's sources of power. We were unable to obtain sufficient data to perform this analysis for each plant but were able to produce calculations of production cost expense by generation technology and further recommended that the Commission require such analysis by plant.[89] Our analysis of these costs in U-20561 was based on the unbundled cost of service study presented by DTEE Electric witness Thomas Lacey.[90] The Commission ultimately ordered DTE Electric to provide costs by plant in its next rate case.[91] In the present case, Mr. Lacey provided an analysis of costs by plant and this is the full scope of his testimony.[92] His results are displayed in Exhibit A-32.

Q. Do you agree with Mr. Lacey's results in the Plant Study?

A. No. He made certain errors in his analysis. In addition, his analysis was based on cost summaries[93] presented by Habeeb J. Maroun, which themselves contained certain errors that were made apparent by my examination of Mr. Lacey's Exhibit A-32. Importantly, these errors also affect Mr. Maroun's calculation of capacity costs for purposes of the State Reliability Mechanism as presented in Exhibit A-16 Schedule F1.5.

Q. Please explain the relationships amongst Exhibit A-32, Exhibit A-16 F1.1 and Exhibit A-16 F1.5?

A. In Exhibit A-32, Mr. Lacey created a column for each plant that he included in the Plant Study with a series of rows corresponding to the rows in Exhibit A-16 F1.1 He then allocated to total costs shown in column (a) of Exhibit A-16 F1.1 and in column (a) of Exhibit A-32 to the various plants represented by the columns in his Exhibit A-32.

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[89] See U-20561 Direct Testimony of Karl Boothman.

[90] See U-20561 Direct Testimony of Thomas G. Lacey.

[91] Case No. U-20561, May 8, 2020, Order, pp. 220-221.

[92] Direct Testimony of Thomas G. Lacey.

[93] Exhibit A-16, Schedule F1.1.

Exhibit A-16 F1.5 summarizes those same data from Exhibit A-16 F1.1 column (a) in a particular way and additionally provides an estimate of the market value of energy, in order to calculate DTE's costs of capacity for purposes of the State Reliability Mechanism. I shall explain the relationship between Exhibit A-16 F1.1 and Exhibit A-16 F1.5 more precisely below.

Q. What errors did Mr. Lacey make in developing Exhibit A-32?

A. I present adjustments to Exhibit A-32 in my Exhibit MEC-9. I explain each adjustment in turn below.

First, Mr. Lacey labels his row 20 as "Return@5.7338 %", but that rate of return is not the rate of return used by DTE Electric in the rest of this case and is not consistent with the values shown in that row or Exhibit A-32. I have therefore corrected the label in my Exhibit MEC-9 to read "Return@5.556 %" and have used the correct formula in making further adjustments to convert Exhibit A-32 into my Exhibit MEC-9.

Second, row 4 of Exhibit A-32 and row 4 of Exhibit A-16 F1.1 are labeled as "Fuel" but includes payments for transmission services which Mr. Lacey shows in column (aq) of Exhibit A-32. This labeling error is not of great consequence in the determination of costs by plant in Exhibit A-32 but leads to a conceptual error in Exhibit A-16 F1.5 so I correct it Exhibit MEC-9 by splitting row 4 into rows 4a and 4b and assigning the cost of transmission services to row 4b. The sum of rows 4a and 4b in my Exhibit MEC-9 matches row 4 in Mr. Lacey's Exhibit A-32.

Third, column (ap) of Mr. Lacey's Exhibit A-32 allocates a portion of the total production costs in column (a) to MERC (the Midwest Energy Resources Company). As discussed in the testimony of D. C. Milo,[94] "MERC is a wholly-owned subsidiary of DTE Electric, which provides coal transportation services to DTE Electric and coal transportation services to third-party utility and industrial customers through its Superior, WI, terminal." As such, MERC is not a generating plant that should be allocated costs in the Plant Study but is instead a fuel supply cost for DTE Electric's Belle River and Monroe Plants.[95] In my Exhibit MEC-9, I subtract the full revenue requirement of MERC ($7.413 million) as shown in column (ap) from that column by showing it as Miscellaneous Revenue in row 26 of column (ap) and allocating that amount to the Belle River and Monroe plants in row 4c in proportion to their respective fuel costs as shown in row 4a. Because Mr. Lacey had constructed the plant "revenue" that he included in row 2 so as to create unform actual return on equity for each plant, I also added the MERC costs into the line 2 revenue requirements for each Belle River and Monroe coal unit.

Fourth, Mr. Lacey took the extraordinary step of allocating purchased power costs to each plant in his analysis, including to transmission. But, purchased power costs consist of payments to counterparties in power purchase agreements plus costs of net interchange power with the Midcontinent Independent System Operator ("MISO") which are themselves sources of power. It simply makes no sense to allocate costs of purchased power as though they are operating expenses of DTE -owned power plants. I therefore created a new column in the analysis, which I labeled as (pp) so as make simple any comparisons of corresponding columns in my Exhibit MEC-9 and Exhibit A-32. Column (pp) in my Exhibit MEC-9 presents the total costs of purchased power as an expense in the correct

[94] Direct Testimony of D. C. Milo, DCM-5:13-16.

[95] Exhibit A-32 allocates costs in the projected test year when these are the only DTE Electric coal plants that continue to operate.

way. I also removed all allocations of purchased power to other plants from row 5. Because Mr. Lacey had included those purchased power costs that he allocated to each plant in the plant "revenue" he included in row 2, I also removed the purchased power amounts that were in his row 5 from the revenue for each plant in row 2.

Q. Based on Mr. Lacey's Exhibit A-32 and the corrections thereto that you just described, what adjustments to Exhibit A-16 F1.5 do you recommend?

A. I provide a corrected version of Exhibit A-16 F1.5 as Exhibit MEC-11. I explain those corrections below.

First, note that in column (a) of Exhibit A-16 F1.5, the entry in Line 1, labeled as Net Production Costs Rev. Req. ties to column (a) of Exhibit A-16 F1.1 line 27, which also ties to column (a) of Exhibit A-32 line 27 and my Exhibit MEC-9. According to MCL 460.6w (3), the calculation of capacity charges that is the purpose of Exhibit A-16 F1.5 is to begin with generation costs, not production costs. These differ by the inclusion of transmission costs that are shown in column (aq) of Exhibit A-32 and corrected in my Exhibit MEC-9. I therefore reduce the $3,183,715 amount in Exhibit A-16 F1.5 by the transmission Net Production Costs Rev Req in Line 27 of Exhibit MEC-9, which is $325,477, so that my entry in column (a) Line 1 is $2,858,238. DTE Electric might argue that they remove transmission costs in Line 2 of Exhibit A-16 F1.5 because they included transmission expenses in the Fuel costs shown there. However, the transmission expenses included in "Fuel" on Line 2 are only $317,922 and do not include other transmission costs that are included in column (aq) of Exhibit A-32 as corrected in my Exhibit MEC-9, so my revision is the correct one.

Second, Line 2 of Exhibit A-16 F1.5 does include $317,922 of transmission expenses that I deducted from the revenue requirement in Line 1 of my Exhibit MEC-11 and fails to include the $7,413 MERC costs from column (ap) of Exhibit A-32 that I reassigned as fuel costs in my Exhibit MEC-9. I have therefore revised Line 2 of Exhibit A-16 F1.5 in my Exhibit MEC-11 by removing transmission expenses and adding MERC revenue requirements to, net of these changes, reduce fuel costs to $653,302.

Third, I note that variable O&M as displayed in Line 5 of Exhibit A-16 F1.5 is developed in Exhibit A-16 Schedule F1.5 page 5 of 5. As shown there, variable O&M is calculated by subtracting labor O&M from Total O&M. Line 1 of that table is for O&M expenses involved in fuel handling, hence DTE Electric is excluding from variable O&M the labor expense of fuel handling. According to MCL 460.6w (3) (b) capacity costs are to calculated net of all non-capacity-related electric generation costs. O&M labor for handling fuel is obviously non-capacity-related and should be deducted in full from generation costs for the determination of capacity costs. I have therefore included $17,755 of fuel handling O&M costs in Line 5 of Exhibit MEC-11.

Fourth, Exhibit A-32 as corrected in Exhibit MEC-9 includes net revenue requirements for St. Clair Units 1, 2, 3, 6, and 7 and Trenton Unit 9. The total of those revenue requirements from line 27 is $56,102. MCL 460.6w (3) specified that non-capacity-related electric generation costs include “net stranded cost recovery”. The costs allocated to these plants that will be retired by the projected test year, if authorized for recovery, should be classified as net stranded cost recovery for purposes of determining the capacity costs under MCL 460.6w (3). I have therefore deduced this amount from Line 1 of my Exhibit MEC-11, reducing that value to $2,802,137.

I therefore obtain a capacity-costs subtotal of $1,846,144 in column (a) of Exhibit MEC-11 Line 6 as compared to $1,934,968 in that cell of Exhibit A-16 F1.5. This change in capacity-related revenue requirement also causes a change in non-capacity-related revenue requirement to $1,987,439 in Exhibit MEC-11 Line 11 as compared to the corresponding value of $1,898,614 in Exhibit A-16 F1.5.

Q. Based on the corrections to Mr. Lacey's Exhibit A-32 and Exhibit A-16 F1.5 that you just described, do you have any recommendations to the Commission?

A. Yes, I recommend that the Commission determine that the full cost of MERC is a fuel cost for purposes of the unbundled cost of service study and direct that the unbundled cost of service study be corrected in this regard. I further recommend that the Commission determine that all O&M costs for fuel handling are fuel costs for purposes of both the unbundled cost of service study and the development of capacity-related and non-capacity-related revenue requirements in Exhibit A-16 F1.5.

Q. Have you made any further changes from Exhibit A-16 F1.5 in preparing Exhibit MEC-11?

A. Yes. Exhibit A-16 F1.5 includes in Line 7 the projected 2022 Energy Sales Revenue net of Fuel-Related Costs including 2020 reconciliation, as shown in Exhibit A-26 Exhibit P3, Line 28. I have shown in Exhibit MEC-11 Lines 7a and 7b the actual projected 2022 Energy Sales Revenue net of Fuel-Related Costs as shown in Exhibit A-26 P3 Line 26 and the 2020 Reconciliation of Net Sales Benefit Difference as shown in Exhibit A-26 P3 Line 27. Displaying these does not of itself change other values in Exhibit MEC-11 but facilitates some of my later discussion of this information.

Q. Absent the adjustment for 2020 Reconciliation of Net Sales Benefit Difference, what would the values in Exhibit MEC-11 have been for capacity-related and non-capacity-related revenue requirements?

A. Absent this adjustment, the capacity-related revenue requirement in Line 6 of Exhibit MEC-11 would have been $950,981 and the non-capacity-related revenue requirement would have been $2,232,734. In my opinion, these values reflect DTE Electric's projected actual capacity-related and non-capacity-related revenue requirements for the projected test year. If not for reconciliation of 2020 capacity costs, the net capacity-related revenue requirement would be 52% of DTE Electric's generation plant costs as shown in Line 6 of Exhibit MEC-11. If the adjustment for 2020 reconciliation was not made in calculating this ratio, then it would be 65%.

Q. What is the significance of that ratio?

A. MCL 460.6w (3) specifies that the calculations in Exhibit A-16 F1.5 as I have corrected or revised them in Exhibit MEC-11 are to be done "[i]n order to ensure that noncapacity electric generation services are not included in the capacity charge…." The result of the calculation specified by the legislature in order to ensure that non-capacity electric generation services are not included in the capacity charge demonstrates that the 75-0-25 4CP method for allocation of plant costs used by DTE Electric in the unbundled cost of service study in this case does not reflect cost of service. The actual ratio is either 52% or 65%, depending on the treatment of reconciliation from previous years and is not 75%. The Commission should therefore modify that method as authorized in MCL 460.11.

Q. How do you recommend that the Commission direct DTE Electric to allocate production plant costs in its cost of service studies?

A. I recommend that the Commission direct DTE Electric to determine capacity-related and non-capacity-related costs in the cost of service study using the principles specified in MCL 460.6w, using the methods applied in Exhibit A-16 F1.5 with the corrections that I have shown in ExhibitMEC-11, rather than by using a fixed percentage of plant costs. Rather than adopt a new percentage allocation of generator plant costs as capacity-related vs non-capacity-related, I recommend allowing DTE Electric's evolving cost structure as revealed in A-16 F1.5 as I corrected it in Exhibit MEC-11 determine that allocation case-to-case.

In order to preserve the effects of the reconciliation of capacity-related costs as provided in MCL 460.6w (3), this allocation could be based on the determination of capacity-related and non-capacity-related costs adjusted for reconciliation of the previous period; in this current case my recommendation would therefore result in 65% of generation plant costs being allocated as capacity-related. The Commission can implement this recommendation in the current case by allocating 65% of production plant costs based on 4CP and 35% based on energy.

Until there is a showing that 4CP is not the best allocator of capacity costs to rate classes, that allocator should be used to allocate capacity-related costs and the appropriate energy-related allocator should be applied to non-capacity-related generation costs. Transmission costs, which are charged to DTE Electric based on monthly system peak demand should continue to be allocated based on a 12CP allocator.

Q. Do you recommend that the Commission require DTE Electric to perform the Plant Study in future rate cases?

A. I do. Providing that information will facilitate careful consideration of the value of each plant in DTE Electric's generation portfolio as well as increasingly accurate production cost allocation. Several analyses that I would have done in testimony in this case were not practical or meaningful because of the transition in DTE Electric's generation portfolio that is occurring between the historical and projected test years in this case and associated information gaps.

I further recommend that the Commission require DTE Electric to calculate capacity-related and non-capacity-related costs for each plant consistent with the method used in Exhibit A-16 F1.5 using whatever approach to constructing Exhibit A-16 F1.5 as the Commission may specify as a result of my recommendations.

VIII. <u>RATE DESIGN</u>

Q. Please summarize DTE Electric's rate design proposals in this case?

A. DTE Electric presents its rate design proposals primarily through the testimony of Aaron Willis[96] and Neal T. Foley.[97]

With respect to residential rates, DTE Electric proposes to maintain the structure of most rate schedules, changing the rates applied to billing determinants to align revenue with the revenue requirements determined in DTE Electric's cost of service study. In addition, DTE Electric proposes to create rate schedules D1.11 and D1.12. Rate Schedule D1.11 is a time-

[96] Direct Testimony of Aaron Willis, AW-8:1 through AW-35:15.

[97] Direct Testimony of Neal T. Foley, NTF-4:3 through NTF-47:26.

of-use rate schedule, to which DTE Electric will move most residential customers on an opt-out bases and will adopt as the default rate for new residential customers.[98] DTE Electric describes rate schedule D1.12 as a "stable bill service level" demand-based tariff and characterizes it as voluntary, though they also propose to require customers using distributed generation under Rider 18 to accept assignment to rate schedule D1.12.

With respect to secondary commercial rates, the only structural change proposed by DTE Electric in this case is the addition of a rate for its proposed EV Hubs, in which there would be a "session charge" as well as a volumetric energy charge.

With respect to primary commercial and industrial rates, DTE Electric is not proposing any structural changes in this case.

Q. What guidance has the legislature given the Commission regarding rate design generally?

A. MCL 460.11 directs that" Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid.".

Q. Are there other factors the Commission should consider in reviewing rate design?

A. Yes, the Commission should recognize that rate design incents customer behavior, which can affect power system reliability, customer activity schedules, the relative attractiveness to customers of various forms of energy efficiency investments, the likelihood for customers to adopt electricity end-uses such as transportation or building heat, and the

[98] Foley Direct, NTF-27:7 through NTF-33:2.

likelihood for customers to adopt behind-the-meter generation or storage resources. These incentive effects in turn affect the utility's revenue requirements and cost of service. Fortunately, rate designs that most closely match cost of service for individual customers are also likely to incent customer behavior that maximizes customer net benefits relative to power system internal costs. Consequently, there is a potential conflict between adherence to cost of service as a basis for rate design and desirable incentive effects only to the extent that the power system externalizes costs.

Q. How can rate design best align with cost of service?

A. Much of the cost of the power system is to provide capacity for generation, transmission or production. With very important exceptions, such as the effect of ambient temperature on transmission and distribution system capacities, those capacities are available throughout the year. It is also important to recognize that capacities have varying degrees of localization. Generation capacity is basically pooled at a regional level, subject to transmission capacity constraints that limit the geographical scope of generation capacity pooling to the quantities that can be delivered over the transmission system. On the other extreme, distribution transformer capacity is only supplied to the customers that are connected to the transformer. These facts argue for rates that are high at times of high capacity utilization and low at times of low capacity utilization.

On the other hand, some portion of each capacity in the power system is used at virtually any time. The cost of capacity that is used much of the time cannot properly be said to be caused by the requirements at peak demand times.

An efficient rate design will charge customers the marginal cost of a given capacity at times of peak demand and recover any remaining costs relatively uniformly at all other times.

For example, a critical peak pricing strategy will charge customers the cost of new entry of generation capacity at a time of peak system-wide power demand and recover all other costs through a uniform energy charge or through marginal energy costs at any other time. A less efficient but more equitable rate design will allocate costs of each increment of capacity to all times when it is used, resulting in higher rates at times when rarely used capacity is used but spreading base levels of capacity across the entire year and intermediate levels of capacity across much of the year. Generally, a rate design that charges a uniform rate at all times, without regard to the level of capacity utilization, will be neither efficient in the price signals it provides to customers nor equitable in its allocation of costs.

Q. Based on these criteria, what is your evaluation of the proposed rate schedule D1.11?

A. The proposed rate schedule D1.11 is a small step in the right direction. It applies time of use rates to the non-capacity-related production costs allocated to residential customers. The proposed pricing intervals are likely not ideal, especially in the long-run, but are not unreasonable so I do not object to them at this time. The use of LMP differences to establish price differentials is also reasonable at this time.

The use of non-varying rates for capacity-related production costs and for distribution costs is neither efficient nor equitable. The portions of each of these cost categories driven by costs of capacities is very large and very seasonal. DTE Electric acknowledges and advocates for this perspective in that it allocates most production plant costs based on 4CP – the customer class shares of demand at the time of the monthly peaks in the months June through September and allocates distribution costs based primarily on customer class shares of annual peak demand at each voltage level, which typically occurs late on a summer afternoon. Consequently, the rates for capacity-related production costs and for distribution costs do not provide a material price signal about patterns of power usage and inequitably allocate costs to customers who have various patterns of usage.

Q. Based on these criteria, what is your evaluation of the proposed rate schedule D1.12?

A. Aside from DTE's previous proposal to establish a Fixed Bill Pilot, proposed in Case No. U-20561, the proposed rate schedule D1.12 is the most inefficient and unjust residential rate design that I have reviewed. It would effectively allocate capacity-related and distribution costs to an annually-ratcheted non-coincident customer demand charge based on three hours of the year. Consequently, it would not only fail to provide useful price signals to customers to minimize system costs, but it also would send perverse price signals that customers should

- Use power as freely at the time of system power supply peaks as at any other time, thereby undermining reliability and driving up generation capacity requirements and costs;
- Avoid adopting an electric vehicle, and particularly avoid level 2 charging, because of the high demand charges that would result even though level 2 charging at times of low demand are beneficial to both the customer with an EV and to other customers who benefit from incremental load that complements existing load;
- Avoid adopting electric heat even though generation and distribution peaks are in summer and the adoption of electric heat will not require additional generation or distribution capacity at the level of adoption that.

DTE Electric has offered no evidence that individual residential non-coincident demand is cost causative, so this proposal is not justified on that basis either. Indeed, the choice of cost allocators in DTE Electric unbundled cost of service study clearly demonstrate that individual non-coincident demand is not material to cost causation.

The Regulatory Assistance Project ("RAP") recently published a paper demonstrating that demand charges do not reflect cost causation and are economically inefficient,[99] and fully reflects my own views, much of which I have expressed in previous testimony. Rather than rewriting that material yet again, I strongly urge the Commission's attention to the RAP paper. This particular proposal is worse than typical demand charges because in includes what is essentially an annual ratchet. It is an unjust proposal in that it gulls customers into behaviors that increase DTE Electric's total system costs and the costs that are allocated to the residential class by sending false price signals.

The fact that DTE Electric proposes that rate schedule D1.12 will be voluntary is not availing since they propose to make it mandatory for customers with distributed generation and make it clear that their intent is to migrate residential customers toward a rate of this design.

Q. How do you recommend that the Commission respond to DTE Electric's rate design proposals in this case?

A. I recommend that the Commission accept the creation of Rate Schedule D1.11 subject to such changes in rates for each billing determinant as result from the Commission's decisions about revenue requirements and cost allocation in this case.

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[99] Exhibit MEC-13 Regulatory Assistance Project. Demand Charges: What are They Good For? Obtained from https://www.raponline.org/wp-content/uploads/2020/11/rap-lebel-weston-sandoval-demand-charges-what-are-they-good-for-2020-november.pdf.

I recommend that the Commission reject DTE Electric's proposed D1.12 rate schedule.

I further recommend that the Commission direct DTE Electric to propose modification of rate schedule D1.11 in its next rate case to include time of use rates for both capacity-related costs and distribution costs in addition to non-capacity-related costs.

IX. DISTRIBUTED GENERATION

Q. Please summarize DTE Electric's proposals regarding distributed generation.

A. In this case, DTE Electric proposes a bargain, providing a modest voluntary increase in the "cap" of the distributed generation program covered by Rider 18 in return for requiring all Rider 18 customers to use the proposed D1.12 rate schedule for inflow and reducing outflow credits to locational marginal price.[100]

Q. Is this a proposal that the Commission should accept, subject to potential adjustments?

A. No. The often referenced "cap" on distribution generation is in fact a minimum obligation of the utility to accept distributed generation customers under a specified set of terms. It does not in fact cap distributed generation generally but leaves open for the Commission to determine appropriate treatment for distributed generation once the "cap" is exceeded. In particular, behind-the-meter solar generation that makes up most of the distributed generation under Rider 18 is a "qualifying facility" under PURPA.[101] As such, the outflow from a customer with distributed generation would be eligible for compensation at DTE Electric's avoided cost. That avoided cost would almost certainly not be less than locational

[100] Foley Direct, NTF-48:1 through NTF-66:25.

[101] See https://www.ferc.gov/qf.

marginal price and very likely would be greater.[102] Further, any requirement that residential customers with distributed generation take service under a different rate schedule than other residential customers should be denied unless DTE Electric demonstrates that such a requirement is due discrimination; DTE Electric has not done so in this case. The Commission should not accept such a bargain.

Q. Please explain how DTE Electric could demonstrate that discrimination such as requiring customers with distributed generation to use a specific rate is due discrimination?

A. Simply, DTE Electric would need to demonstrate that the cost of service for such customers is such that they would not pay appropriate revenue under the alternative tariffs and that the tariff they propose to require for customers with distributed generation more accurately charges such customers than the alternative tariffs.

Q. Why do you say that DTE Electric has not demonstrated that their proposal is due discrimination?

A. DTE Electric has not presented a calculation of the cost of service for customers with distributed generation determined in the same manner as DTE Electric calculates the cost of service for all customers in the unbundled cost of service study. Until and unless DTE Electric makes that calculation and compares the resulting cost of service to the revenue that a customer with distributed generation would pay under the prevailing residential customer tariffs, DTE has not provided a basis for the Commission to determination that overt discrimination with respect to distributed generation is due.

[102] See Case No. U-18091, September 26, 2019, Order.

Q. What do you recommend the Commission do in response to DTE Electric's request to require Rider 18 customers to use rate schedule D1.12?

A. I recommended above that the Commission reject the proposal to establish rate schedule D1.12. In the event that the Commission does authorize rate schedule D1.12, I recommend that the Commission reject DTE Electric's request to require customers with distributed generation to take service under rate schedule D1.12.

I further recommend that the Commission direct DTE Electric to provide an analysis in its next case of the cost of service for customers in each class who have behind-the-meter distributed generation, using the same methods to allocate costs as are used in its overall unbundled cost of service study, and to provide a comparison of that cost of service to the revenue that will be paid to DTE Electric by customers with distributed generation that choose to be in each of the available rate schedules. Since there is considerable variation in load profiles amongst residential customers who do not have distributed generation, the Commission should further require DTE Electric to show how any deviation between revenue and cost of service for customers with distributed generation compares to common such deviations amongst customers who do not have distributed generation.

Q. DTE also proposes to reduce bill credits for outflow to locational marginal price. How should the Commission respond to that request?

A. The Commission should reject that proposal and should instead change the outflow credit from production cost less transmission cost to full production cost applicable in the customer's tariff at the time of the outflow. Exhibit MEC-12 provides DTE Electric's responses to discovery requests on this subject. These unequivocally demonstrate that for purposes of transmission charges to DTE from MISO and for purposes of compliance with

MISO's resource adequacy standards, DTE Electric treats outflow as "negative load". Each kWh of outflow from customers with distributed generation in the peak hour of the month reduces the kW of transmission services for which DTE Electric pays by that outflow adjusted for line losses. Each kWh of outflow from customers with distributed generation during the peak load hour that is used to determine DTE Electric's resource adequacy obligations reduces the resources that DTE Electric must provide by a kW adjusted upward for line losses, plus the planning reserve margin that MISO applies to peak demand to determine resource obligations. Whether the Commission looks to allocated costs or to avoided costs as the basis for outflow rates, those rates must include an appropriate credit for energy, capacity, and transmission.

X. RECOMMENDATIONS

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission:

1) Examine the causes of Michigan's high residential rates compared to neighboring and other states by directing DTE Electric and the Commission Staff to undertake such a study, subject to advice and review by stakeholders. That study should specifically examine the effects of financial parameters such as return on capital, depreciation rates, production cost allocation, distribution cost allocation, and electricity sales per household.
2) Approve or accelerate DTE Electric's tree trimming surge in order to cost-effectively improve distribution system reliability.
3) Be cautious about approving increased spending on grid component replacement based on age until DTE Electric better demonstrates cost-effectiveness and a glidepath to reliability improvements and costs associated with the replacements.

4) Require DTE Electric to prepare another revision of its Distribution Grid Plan and submit it to the Commission not later than approximately September 2023, with specific instructions for:
    a. consideration of equitable reliability in prioritizing DTE Electric's distribution system spending;
    b. developing an approach to managing EV charging that will schedule charging in consideration of local distribution system considerations and incorporate opportunities provided by vehicle-to-home technologies;
    c. replacing DTE's assessment of asset health based largely on age statistics with one more thoroughly based in reliability and repair theory and the life distribution analyses that are included in utility depreciation studies;
    d. optimization of monitoring and inspection programs to support equipment replacement based on conditions indicating incipient failure;
    e. the development and presentation of local load data and forecasts;
    f. a reexamination of distribution system cost allocation based on engineering practices, with a particular focus on the allocation of costs by time; and
    g. inclusion of rate impact for each category of spending and for the plan as a whole.
5) Consider requiring that utilities present distribution system plans for examination in contested cases to establish parameters to be incorporated into subsequent rate cases.
6) Support continuation of DTE Electric's Charging Forward pilots, subject to the following caveats:

a. DCFC make-ready and rebate programs should be modified to ensure that make-ready infrastructure is capable of supporting 350 kW DCFCs and DCFC rebates should require that the DCFCs should support at least 150 kW charging rates;

b. The Commission should authorize spending the make-ready investments and customer rebates proposed by DTE Electric in the Charging Forward pilot faster than the schedule proposed by DTE Electric in this case, if customer demand warrants;

c. The Commission should require that participants in the residential CaaS program be required to choose between a time of use tariff and participation in the BYOC program;

d. The Commission should order DTE to provide online charging capacity maps of its system to address the need for charging infrastructure providers to locate DCFC stations similar to DTE Electric's proposed Charging Hubs;

e. If the Commission authorizes vehicle purchase rebates to low-income customers, those rebates should be made available on a point-of-sale basis;

f. If the Commission authorizes vehicle purchase rebates to low-income customers, the Commission should deny DTE Electric's request for cost recovery to create an on-line donation portal in support of that program.

7) Direct DTE Electric to file a proposal for a permanent EV charging infrastructure program not later than March 15,2023. That proposal should be designed

a. to scale with EV adoption;

b. such that non-participating customers are no worse off as a result of customer participation in the EV infrastructure program, similar to line extension policy;

c. ensure that residential customers do not need to individually pay for distribution system upgrades to support residential EV charging by establishing that policy and prioritizing distribution system readiness in this permanent program;

d. ensure that there is adequate public charging infrastructure to support EV adoption;

e. require standardized reporting about and projections of the numbers of vehicles in DTE Electric's service territory and their charging activity and revenue contributions by customer class; and

f. continue implementing pilot programs to respond to evolving technology and infrastructure needs.

8) Adopt the corrections to the capacity cost calculations in A-16 F1.5 that I present in testimony and in Exhibit MEC-11 and instruct DTE Electric that future capacity calculations are to be done in this fashion.

9) Direct DTE Electric that all MERC costs are to be treated as fuel costs in its unbundled cost of service study.

10) Conclude that the capacity cost calculations in A-16 F1.5, especially as corrected in Exhibit MEC-11 demonstrate that the 75-0-25 4CP method for allocation production plant costs does not reflect cost causation and direct that DTE Electric develop its future unbundled cost of service study by first calculating capacity-related and non-capacity-related costs using the methods in Exhibit MEC-11, then

allocating capacity-related costs based on 4CP and non-capacity-related costs based on energy usage metrics. In the present case, this change can be accomplished by allocating production plant costs 65% based on 4CP and 35% based on energy.

11) Require DTE Electric to prepare a Plant Study similar to that in Exhibit A-32 in future cases, subject to the corrections discussed in my testimony, and to include in that Plant Study the separation of costs of each plant into capacity-related and non-capacity-related costs as developed in Exhibit MEC-11.

12) Approve DTE Electric's proposed design for rate schedule D1.11 subject to such revisions or rates for each billing determinant as may emerge from this case and its proposed migration of residential customers to rate schedule D1.11 on an opt-out basis.

13) Direct DTE Electric to propose in its next rate case modifications to rate schedule D1.11 to include time-of-use rates for capacity and distribution.

14) Reject DTE Electric's proposed rate schedule D1.12.

15) If the Commission authorizes the use of rate schedule D1.12, reject DTE Electric's proposal to require customers with distributed generation to use rate schedule D1.12 as undue discrimination.

16) Reject DTE Electric's proposal to reduce bill credits for outflow in Rider 18 to locational marginal price and require instead that they be equal to production cost portion of the customer's underlying inflow rate schedule at the time of outflow, including transmission costs.

Q. Does that complete your testimony?

A. Yes.

Douglas B. Jester

Personal Information

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Lansing, MI 48933
517-337-7527
djester@5lakesenergy.com

Professional experience

January 2011 – present 5 Lakes Energy

Partner

Co-owner of a consulting firm working to advance the clean energy economy in Michigan and beyond. Consulting engagements with foundations, startups, and large mature businesses have included work on public policy, business strategy, market development, technology collaboration, project finance, and export development concerning energy efficiency, smart grid, renewable generation, electric vehicle infrastructure, and utility regulation and rate design. Policy director for renewable energy ballot initiative and Michigan energy legislation advocacy. Supported startup of the Energy Innovation Business Council, a trade association of clean energy businesses. Expert witness in utility regulation cases. Developed integrated resource planning models for use in ten states' compliance with the Clean Power Plan.

February 2010 - December 2010 Michigan Department of Energy, Labor and Economic Growth

Senior Energy Policy Advisor

Advisor to the Chief Energy Officer of the State of Michigan with primary focus on institutionalizing energy efficiency and renewable energy strategies and policies and developing clean energy businesses in Michigan. Provided several policy analyses concerning utility regulation, grid-integrated storage, performance contracting, feed-in tariffs, and low-income energy efficiency and assistance. Participated in Pluggable Electric Vehicle Task Force, Smart Grid Collaborative, Michigan Prosperity Initiative, and Green Partnership Team. Managed development of social-media-based community for energy practitioners. Organized conference on Biomass Waste to Energy.

August 2008 - February 2010 Rose International

Business Development Consultant - Smart Grid

- Employed by Verizon Business' exclusive external staffing agency for the purpose of providing business and solution development consultation services to Verizon Business in the areas of Smart Grid services and transportation management services.

December 2007 - March 2010 Efficient Printers Inc

President/Co-Owner

- Co-founder and co-owner with Keith Carlson of a corporation formed for the purpose of acquiring J A Thomas Company, a sole proprietorship owned by Keith Carlson. Recognized as Sacramento County (California) 2008 Supplier of the Year and Washoe County (Nevada) Association for Retarded Citizens 2008 Employer of the Year. Business operations discontinued by asset sale to focus on associated printing software services of IT Services Corporation.

August 2007 - present IT Services Corporation

President/Owner

- Founder, co-owner, and President of a startup business intended to provide advanced IT consulting services and to acquire or develop managed services in selected niches, currently focused on developing e-commerce solutions for commercial printing with software-as-a-service.

2004 – August 2007 Automated License Systems

Chief Technology Officer

- Member of four-person executive team and member of board of directors of a privately-held corporation specializing in automated systems for the sale of hunting and fishing licenses, park campground reservations, and in automated background check systems. Executive responsible for project management, network and data center operations, software and product development. Brought company through mezzanine financing and sold it to Active Networks.

2000 - 2004 WorldCom/MCI

Director, Government Application Solutions

- Executive responsible in various combinations for line of business sales, state and local government product marketing, project management, network and data center operations, software and product development, and contact center operations for specialized government process outsourcing business. Principal lines of business were vehicle emissions testing, firearm background checks, automated hunting and fishing license systems, automated appointment scheduling, and managed application hosting services. Also responsible for managing order entry, tracking, and service support systems for numerous large federal telecommunications contracts such as the US Post Office, Federal Aviation Administration, and Navy-Marine Corps Intranet.
- Increased annual line-of-business revenue from $64 million to $93 million, improved EBITDA from approximately 2% to 27%, and retained all customers, in context of corporate scandal and bankruptcy.
- Repeatedly evaluated in top 10% of company executive management on annual performance evaluations.

1999-2000 Compuware Corporation

Senior Project Manager

- Senior project manager, on customer site with five project managers and team of approximately 80, to migrate a major dental insurer from a mainframe environment to internet-enabled client-server environment.

1995 - 1999 City of East Lansing, Michigan

Mayor and Councilmember

- Elected chief executive of the City of East Lansing, a sophisticated city of 52,000 residents with a council-manager government employing about 350 staff and with an annual budget of about $47 million. Major accomplishments included incorporation of public asset depreciation into budgets with consequent improvements in public facilities and services, complete rewrite and modernization of city charter, greatly intensified cooperation between the City of East Lansing and the East Lansing Public Schools, significant increases in recreational facilities and services, major revisions to housing code, initiation of revision of the City Master Plan, facilitation of the merger of the Capital Area Transportation Authority and Michigan State University bus systems, initiation of a major downtown redevelopment project, City government efficiency improvements, and numerous other policy initiatives. Member of Michigan Municipal League policy committee on Transportation and Environment and principal writer of league policy on these subjects (still substantially unchanged as of 2009).

1995-1999 Michigan Department of Natural Resources

Chief Information Officer

- Executive responsibility for end-user computing, data center operations, wide area network, local area network, telephony, public safety radio, videoconferencing, application development and support, Y2K readiness for Departments of Natural Resources and Environmental Quality. Directed staff of about 110. Member of MERIT Affiliates Board and of the Great Lakes Commission's Great Lakes Information Network (GLIN) Board.

1990-1995 Michigan Department of Natural Resources

Senior Fisheries Manager

- Responsible for coordinating management of Michigan's Great Lakes fisheries worth about $4 billion per year including fish stocking and sport and commercial fishing regulation decisions, fishery monitoring and research programs, information systems development, market and economic analyses, litigation, legislative analysis and negotiation. University relations. Extensive involvement in regulation of steam electric and hydroelectric power plants.
- Served as agency expert on natural resource damage assessment, for all resources and causes.
- Considerable involvement with Great Lakes Fishery Commission, including:
  - Co-chair of Strategic Great Lakes Fishery Management Plan working group

- Member of Lake Erie and Lake St. Clair Committees
- Chair, Council of Lake Committees
- Member, Sea Lamprey Control Advisory Committee
- St Clair and Detroit River Areas of Concern Planning Committees

1989-1990 American Fisheries Society

Editor, North American Journal of Fisheries Management

- Full responsibility for publication of one of the premier academic journals in natural resource management.

1984 - 1989 Michigan Department of Natural Resources

Fisheries Administrator

- Assistant to Chief of Fisheries, responsible for strategic planning, budgets, personnel management, public relations, market and economic analysis, and information systems. Department of Natural Resources representative to Governor's Cabinet Council on Economic Development. Extensive involvement in regulation of steam electric and hydroelectric power plants.

1983-present Michigan State University

Adjunct Instructor

- Irregular lecturer in various undergraduate and graduate fisheries and wildlife courses and informal graduate student research advisor in fisheries and wildlife and in parks and recreation marketing.

1977 – 1984 Michigan Department of Natural Resources

Fisheries Research Biologist

- Simulation modeling & policy analysis of Great Lakes ecosystems. Development of problem-oriented management records system and "epidemiological" approaches to managing inland fisheries.
- Modeling and valuation of impacts power plants on natural resources and recreation.

Education

1991-1995 Michigan State University
PhD Candidate, Environmental Economics
Coursework completed, dissertation not pursued due to decision to pursue different career direction.

1980-1981 University of British Columbia
Non-degree Program, Institute of Animal Resource Ecology

1974-1977 Virginia Polytechnic Institute & State University
MS Fisheries and Wildlife Sciences
MS Statistics and Operations Research

1971-1974 New Mexico State University
BIS Mathematics, Biology, and Fine Arts

Citizenship and Community Involvement

Youth Soccer Coach, East Lansing Soccer League, 1987-89

Co-organizer, East Lansing Community Unity, 1992-1993

Bailey Community Association Board, 1993-1995

East Lansing Commission on the Environment, 1993-1995

East Lansing Street Lighting Advisory Committee, 1994

Councilmember, City of East Lansing, 1995-1999

Mayor, City of East Lansing, 1995-1997

East Lansing Downtown Development Authority Board Member, 1995-1999

East Lansing Transportation Commission, 1999-2004

East Lansing Non-Profit Housing and Neighborhood Services Corporation Board Member, 2001-2004

Lansing – East Lansing Smart Zone Board of Directors, 2007-present

Council on Labor and Economic Growth, State of Michigan, by appointment of the Governor, May 2009 – May 2012

East Lansing Downtown Development Authority Board Member and Vice-Chair, 2010 – present.

East Lansing Brownfield Authority Board Member and Vice-Chair, 2010 – present.

East Lansing Downtown Management Board and Chair, 2010 – 2016

East Lansing City Center Condominium Association Board Member, 2015 – present.

Douglas Jester
Specific Energy-Related Accomplishments

Unrelated to Employment

- Member of Michigan SAVES initial Advisory Board. Michigan SAVES is a financing program for building energy efficiency measures initiated by the State of Michigan Public Service Commission and administered under contract by Public Sector Consultants. Program launched in 2010.
- Member of Michigan Green Jobs Initiative, representing the Council for Labor and Economic Growth.
- Participated in Lansing Board of Water and Light Integrated Resource Planning, leading to their recent completion of a combined cycle natural gas power plant that also provides district heating to downtown Lansing.
- In graduate school, participated in development of database and algorithms for optimal routing of major transmission lines for Virginia Electric Power Company (now part of Dominion Resources).
- Commissioner of the Lansing Board of Water and Light, representing East Lansing. December 2017 – present.

For 5 Lakes Energy

- Participant by invitation in the Michigan Public Service Commission Smart Grid Collaborative, authoring recommendations on data access, application priorities, and electric vehicle integration to the grid.
- Participant by invitation in the Michigan Public Service Commission Energy Optimization Collaborative, a regular meeting and action collaborative of parties involved in the Energy Optimization programs required of utilities by Michigan law enacted in 2008.
- Participant by invitation in Michigan Public Service Commission Solar Work Group, including presentations and written comments on value of solar, including energy, capacity, avoided health and environmental damages, hedge value, and ancillary services.
- Participant by invitation in Michigan Senate Energy and Technology Committee stakeholder work group preliminary to introduction of a comprehensive legislative package.
- Participant by invitation in Michigan Public Service Commission PURPA Avoided Cost Technical Advisory Committee.
- Participant by invitation in Michigan Public Service Commission Standby Rate Working Group.
- Participant by invitation in Michigan Public Service Commission Street Lighting Collaborative.
- Participant by invitation in State of Michigan Agency for Energy Technical Advisory Committee on Clean Power Plan implementation.
- Conceived, obtained funding, and developed open access integrated resource planning tools (State Tool for Electricity Emissions Reduction aka STEER) for State compliance with the Clean Power Plan:
    - For Energy Foundation - Michigan and Iowa
    - For Advanced Energy Economy Institute – Arkansas, Florida, Illinois, Ohio, Pennsylvania, Virginia
    - For The Solar Foundation - Georgia and North Carolina
- Presentations to Michigan Agency for Energy and the Institute for Public Utilities Michigan Forum on Strategies for Michigan to Comply with the Clean Power Plan.
- Participant in Midcontinent Independent Systems Operator stakeholder processes on behalf of Michigan Citizens Against Rate Excess and the MISO Consumer Representatives Sector, including Resource Adequacy Committee, Loss of Load Expectation Working Group, Transmission Expansion Working Group, Demand Response Working Group, Independent Load Forecasting Working Group, and Clean Power Plan Working Group.
- Expert witness before the Michigan Public Service Commission in various cases, including:

- Case U-17473 (Consumers Energy Plant Retirement Securitization)
- Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation)
- Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17317 (Consumers Energy 2014 PSCR Plan);
- Case U-17319 (DTE Electric 2014 PSCR Plan);
- Case U-17674 (WEPCO 2015 PSCR Plan);
- Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
- Case U-17689 (DTE Electric Cost of Service and Rate Design);
- Case U-17688 (Consumers Energy Cost of Service and Rate Design);
- Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
- Case U-17762 (DTE Electric Energy Optimization Plan);
- Case U-17752 (Consumers Energy Community Solar);
- Case U-17735 (Consumers Energy General Rates);
- Case U-17767 (DTE General Rates);
- Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
- Case U-17895 (UPPCO General Rates);
- Case U-17911 (UPPCO 2016 PSCR Plan);
- Case U-17990 (Consumers Energy General Rates); and
- Case U-18014 (DTE General Rates);
- Case U-17611-R (UPPCO 2015 PSCR Reconciliation);
- Case U-18089 (Alpena Power PURPA Avoided Costs);
- Case U-18090 (Consumers Energy PURPA Avoided Costs);
- Case U-18091 (DTE PURPA Avoided Costs);
- Case U-18092 (Indiana Michigan Electric Power PURPA Avoided Costs);
- Case U-18093 (Northern States Power PURPA Avoided Costs);
- Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
- Case U-18095 (UMERC PURPA Avoided Costs);
- Case U-18224 (UMERC Certificate of Necessity);
- Case U-18255 (DTE General Rate Case);
- Case U-18322 (Consumers Energy General Rate Case).

- Expert witness before the Public Utilities Commission of Nevada in
  - Case 16-07001 (NV Energy 2017-2036 Sierra Pacific Integrated Resource Plan)
- Expert witness before the Missouri Public Service Commission in
  - Case ER-2016-0179 (Ameren Missouri General Rate Case)
  - Case ER-2016-0285 (KCP&L General Rate Case)
  - Case ET-2016-0246 (Ameren Missouri EV Policy)
- Expert witness before the Kentucky Public Service Commission
  - Case 2016-00370 (Kentucky Utilities General Rate Case)
- Expert witness before the Massachusetts Department of Public Utilities in
  - Case 17-05 (Eversource General Rate Case)
  - Case 17-13 (National Grid General Rate Case)
- Coauthored “Charge without a Cause: Assessing Utility Demand Charges on Small Customers”
- Currently under contract to the Michigan Agency for Energy to develop a Roadmap for CHP Market Development in Michigan, including evaluation of various CHP technologies and applications using STEER Michigan as an integrated resource planning tool.
- Under contract to NextEnergy, authored “Alternative Energy and Distributed Generation” chapter of Smart Grid Economic Development Opportunities report to Michigan Economic Development Corporation and assisted authors of chapters on “Demand Response” and “Automated Energy Management Systems”.
- Developed presentation on “Whole System Perspective on Energy Optimization Strategy” for Michigan Energy Optimization Collaborative.
- Under contract to NextEnergy, assisted in development of industrial energy efficiency technology development strategy.

- Under contract to a multinational solar photovoltaics company, developed market strategy recommendations.
- For an automobile OEM, developed analyses of economic benefits of demand response in vehicle charging and vehicle-to-grid electricity storage solutions.
- Under contract to Pew Charitable Trusts, assisted in development of a report of best practices for electric vehicle charging infrastructure.
- Under contract to a national foundation, developed renewable energy business case for Michigan including estimates of rate impacts, employment and income effects, health effects, and greenhouse gas emissions effects.
- Assisted in Michigan market development for a solar panel manufacturer, clean energy finance company, and industrial energy management systems company.
- Under contract to Institute for Energy Innovation, organized legislative learning sessions covering a synopsis of Michigan's energy uses and supply, energy efficiency, and economic impacts of clean energy.

For Department of Energy Labor and Economic Growth

- Participant in the Michigan Public Service Commission Energy Optimization Collaborative, a regular meeting and action collaborative of parties involved in the Energy Optimization programs required of utilities by Michigan law enacted in 2008.
- Lead development of a social-media-based community for energy practitioners in Michigan at www.MichEEN.org.
- Drafted analysis and policy paper concerning customer and third-party access to utility meter data.
- Analyzed hourly electric utility load demonstrating relationship amongst time of day, daylight, and temperature on loads of residential, commercial, industrial, and public lighting customers. Analysis demonstrated the importance of heating for residential electrical loads and the effects of various energy efficiency measures on load-duration curves.
- Analyzed relationship of marginal locational prices to load, demonstrating that traditional assumptions of Integrated Resource Planning are invalid and that there are substantial current opportunities for cost-effective grid-integrated storage for the purpose of price arbitrage as opposed to traditionally considered load arbitrage.
- Developed analyses and recommendations concerning the use of feed-in tariffs in Michigan.
- Participated in Pluggable Electric Vehicle Task Force and initiated changes in State building code to accommodate installation of vehicle charging equipment.
- Organized December 2010 conference on Biomass Waste to Energy technologies and market opportunities.
- Participated in and provided support for teams working on developing Michigan businesses involved in renewable energy, storage, and smart grid supply chains.
- Developed analyses and recommendations concerning low-income energy assistance coordination with low-income energy efficiency programs and utility payment collection programs.
- Drafted State of Michigan response to a US Department of Energy request for information on offshore wind energy technology development opportunities.
- Assisted in development of draft performance contracting enabling legislation, since adopted by the State of Michigan.

For Verizon Business

- Analyzed several potential new lines of business for potential entry by Verizon's Global Services Systems Integration business unit and recommended entry to the "Smart Grid" market. This recommendation was adopted and became a major corporate initiative.
- Provided market analysis and participation in various conferences to aid in positioning Verizon in the "Smart Grid" market. Recommendations are proprietary to Verizon.

- Led a task force to identify potential converged solutions for the “Smart Grid” market by integrating Verizon’s current products and selected partners. Established five key partnerships that are the basis for Verizon’s current “Smart Grid” product offerings.
- Participated in the “Smart Grid” architecture team sponsored by the corporate Chief Technology Officer with sub-team lead responsibilities in the areas of Software and System Integration and Network and Systems Management. This team established a reference architecture for the company’s “Smart Grid” offerings, identified necessary changes in networks and product offerings, and recommended public policy positions concerning spectrum allocation by the FCC, security standards being developed by the North American Reliability Council, and interoperability standards being developed by the National Institute of Standards and Technology.
- Developed product proposals and requirements in the areas of residential energy management, commercial building energy management, advanced metering infrastructure, power distribution monitoring and control, power outage detection and restoration, energy market integration and trading platforms, utility customer portals and notification services, utility contact center voice application enablement, and critical infrastructure physical security.
- Lead solution architecture and proposal development for six utilities with solutions encompassing customer portal, advanced metering, outage management, security assessment, distribution automation, and comprehensive “Smart Grid” implementation.
- Presented Verizon’s “Smart Grid” capabilities to seventeen utilities.
- Presented “Role of Telecommunications Carriers in Smart Grid Implementation” to 2009 Mid-America Regulatory Conference.
- Presented “Smart Grid: Transforming the Electricity Supply Chain” to the 2009 World Energy Engineering Conference.
- Participant in NASPInet work groups of the North American Energy Reliability Corporation (NERC), developing specifications for a wide-area situational awareness network to facilitate the sharing and analysis of synchrophasor data amongst utilities in order to increase transmission reliability.
- Provided technical advice to account team concerning successful proposal to provide network services and information systems support for the California ISO, which coordinates power dispatch and intercompany power sales transactions for the California market.

For Michigan Department of Natural Resources

- Determined permit requirements under Section 316 of the Clean Water Act for all steam electric plants currently operating in the State of Michigan.
- Case manager and key witness for the State of Michigan in FERC, State court, and Federal court cases concerning economics and environmental impacts of the Ludington Pumped Storage Plant, which is the world’s largest pumped storage plant. A lead negotiator for the State in the ultimate settlement of this issue. The settlement was valued at $127 million in 1995 and included considerations of environmental mitigation, changes in power system dispatch rules, and damages compensation.
- Managed FERC license application reviews for the State of Michigan for all hydroelectric projects in Michigan as these came up for reissuance in 1970s and 1980s.
- Testified on behalf of the State of Michigan in contested cases before the Federal Energy Regulatory Commission concerning benefit-cost analyses and regulatory issues for four different hydroelectric dams in Michigan.
- Reviewed (as regulator) the environmental impacts and benefit-cost analyses of all major steam electric and most hydroelectric plants in the State of Michigan.
- Executive responsibility for development, maintenance, and operations of the State of Michigan’s information system for mineral (includes oil and gas) rights leasing, unitization and apportionment, and royalty collection.
- In cooperative project with Ontario Ministry of Natural Resources, participated in development of a simulation model of oil field development logistics and environmental impact on Canada’s Arctic slope for Tesoro Oil.

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UTILITY PERFORMANCE REPORT

RANKING MICHIGAN AMONGST THE STATES

2021 EDITION

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GLOSSARY

Terms and Abbreviations

- ACS: American Community Survey
- CAIDI: Customer Average Interruption Duration Index
- CO2: carbon dioxide
- EIA: Energy Information Administration
- EPA: Environmental Protection Agency
- IEEE: Electrical and Electronics Engineers
- MED: Major Event Days
- NOx: nitrogen oxides of multiple types
- RPS: Renewable Portfolio Standard
- SAIDI: System Average Interruption Duration Index
- SAIFI: System Average Interruption Frequency Index
- SEDS: State Energy Data System
- SO2: sulfur dioxide

Units of Measurement

- GWh: gigawatt hour—one million kilowatt hours
- kWh: kilowatt hour—a unit of electricity measurement typical on U.S. electric bills, the average American household uses about 11,000 kWh per year
- Metric Ton—one million grams or 2204.6 pounds
- MMBTU—one million British thermal units, equivalent to 293.07 kWh
- MWh: megawatt hour—one thousand kilowatt hours
- Therm: one hundred cubic feet of natural gas
- TWh: terawatt hour—one billion kilowatt hours

INTRODUCTION

What is the purpose of an electric utility? Most people would say utilities should deliver reliable and affordable energy service to customers, while at the same time minimizing and managing the environmental impacts caused by the utility's services. This report provides a scorecard that measures how Michigan's electric utilities perform on these criteria in comparison to the aggregate performance of utilities in the other 49 States and the District of Columbia. While aspects of electric utility performance are affected by location, climate, and the composition of the state's economy, these rankings mostly reflect how effective the state's utility regulation policy has been, historically.

Gas utilities face similar performance criteria, but because their performance on safety, reliability, and environmental effects are primarily related to pipeline condition and management, gas utility performance comes down to cost or affordability, as well as gas losses. This report also provides a scorecard measuring the performance of Michigan's gas utilities.

New to this year's report is data on "other heating fuels," which is a category relating to a range of other combustibles used to heat American homes. Other heating fuels data are aggregated and less accessible than electricity or natural gas data. As a result, our presentation of other heating fuels data is limited to figures on cost and use and does not include figures on reliability or environmental impacts.

Table 1: 2019 Michigan Key Metric Ranking

Metric	Michigan 2019 Rank	CAGR
SAIDI with Major Event Days	4	-6%
SAIDI without Major Event Days	6	1%
CAIDI with Major Event Days	3	-6%
CAIDI without Major Event Days	3	-3%
SAIFI with Major Event Days	14	0%
SAIFI without Major Event Days	17	4%
Unaccounted for Natural Gas	20	-
Lost Natural Gas	5	7%
Residential Energy Expenditures as a Percentage of Household Income	19	-4%
Residential Energy Expenditures	16	0%
Percentage of Households Heating with Electricity	48	3%
Percentage of Households Heating with Gas	3	0%
Percentage of Households Heating with Other Heating Fuels	22	-1%
Electricity Use per Household	42	-1%
Natural Gas Use per Household	3	1%
Other Heating Fuel Use per Household	10	5%
Household Electricity Expenditures	39	2%
Residential Electricity Rate	11	2%
Residential Natural Gas Rate	39	-4%

Metric	Michigan 2019 Rank	CAGR
Residential Natural Gas Expenditures	17	-3%
Household Expenditures on Other Heating Fuels	16	1%
Household Other Heating Fuel Rate	40	-3%
Commercial Electricity Rate	13	1%
Industrial Electricity Rate	17	0%
Commercial Natural Gas Rate	37	-3%
Industrial Natural Gas Rate	18	-5%
Interstate Imports and Exports (Higher Rank Implies More Exports)	38	-
Current Largest Source of Generation	Natural Gas	
CO2 Emissions	9	-3%
SO2 Emissions	5	-13%
NOX Emissions	6	-6%
CO2 Emission Intensity	19	-3%
SO2 Emission Intensity	9	-13%
NOX Emission Intensity	16	-6%
Water Withdrawals	7	-
Water Consumption	7	-
Water Withdrawal Intensity	32	-
Water Consumption Intensity	17	-
CO2 Equivalent Emissions from Lost Natural Gas	5	-
CO2 Emissions from Natural Gas Use Outside the Electric Sector	8	-
SO2 Emissions from Natural Gas Use Outside the Electric Sector	8	-
NOX Emissions from Natural Gas Use Outside the Electric Sector	9	-
Residential Electricity Use	15	0%
Residential Natural Gas Use	4	1%
Residential Other Heating Fuel Use	4	4%
Commercial Electricity Use	12	0%
Commercial Natural Gas Use	5	2%
Commercial Other Heating Fuel Use	8	4%
Industrial Electricity Use	10	0%
Industrial Natural Gas Use	12	2%
Industrial Other Heating Fuel Use	13	1%

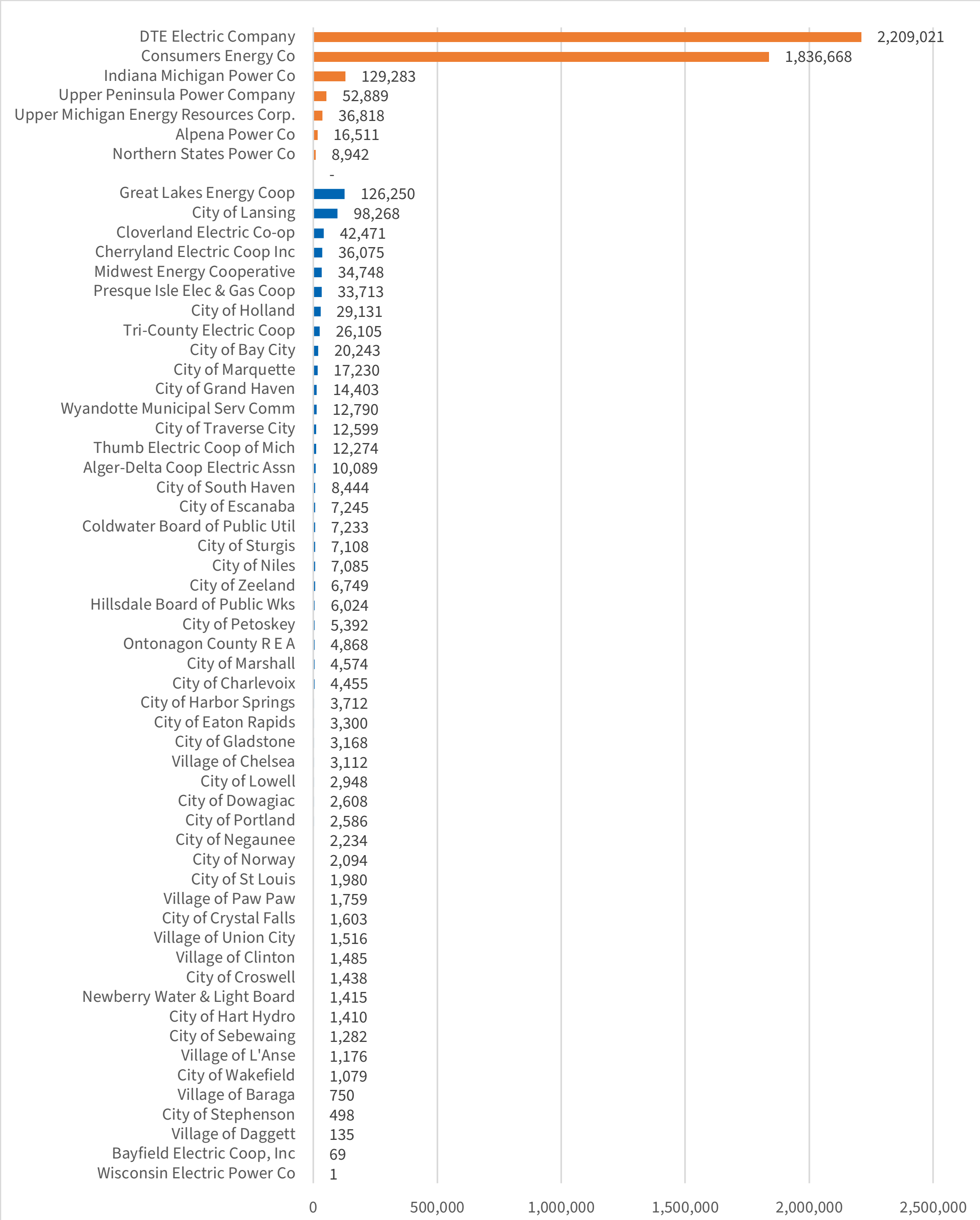
The preceding table shows Michigan's rank for each metric. For each metric reported, states are ranked in order from worst performance to best; a high number implies better performance than a low number. Or, in the case of non-hierarchical metrics such as "residential electricity use," a higher number implies less use.

Because some data are released earlier than others by the Energy Information Administration (EIA) of the US Department of Energy, this report displays some pricing data from 2020, but mostly data pertaining to calendar year 2019.

This report discusses Michigan in relation to a "peer group" consisting of Ohio, Indiana, Illinois, Wisconsin, and Minnesota. These states generally have similar weather, population dynamics, industrial activity, and market conditions, and this comparison introduces some context for the statistics in this report.

The figure below shows the number of customers of each of Michigan's utilities. In this figure (and all utility-level figures in this report), the upper set of bars represents Michigan's regulated utilities, and the lower set of bars represents Michigan's municipal and cooperative utilities. Given the relative scale of Consumers Energy and DTE Energy, Michigan's national statistics are dominated by these two utilities, which sell both electricity and natural gas to Michigan's residents.

Figure 1: 2019 Number of Electricity Customers



ELECTRIC AND NATURAL GAS UTILITY RELIABILITY AND PERFORMANCE

This section takes a deep dive into the available metrics for the reliability and performance of natural gas and electric utilities.

Electric Utilities Overview

Electricity is essential to modern life. As the U.S. moves towards decarbonizing its economy through electrification, electric reliability will become increasingly important, and, in turn, a more reliable electric system will promote electrification. Much of the public discussion about electric utility reliability focuses on what utility regulators and utilities call Resource Adequacy. Resource Adequacy ensures that there is sufficient power generation capacity to satisfy utility customer peak demand. However, loss of electricity supply due to generation or transmission problems accounts for only about 1% of outage minutes nationally. Power outages that utility customers experience on a regular basis are not caused by insufficient generation capacity or long-distance transmission, but by breakdowns in the electricity delivery system—the distribution grid. Distribution breakdowns may occur due to storms breaking powerlines, wildfires, animals touching pairs of power lines and causing a "short," equipment failures, and many other reasons.

The electric power industry, led by the Institute of Electrical and Electronics Engineers (IEEE), has determined that the best overall measure of an electric utility's reliability is the average number of minutes of outage per year per customer, calculated by a method referred to as the System Average Interruption Duration Index (SAIDI). SAIDI is our primary metric for electric reliability, but it is the product of two other reliability metrics: the System Average Interruption Frequency Index (SAIFI), which measures outages per customer, and the Customer Average Interruption Duration Index (CAIDI), which measures the average time for the utility to restore power to a customer after an outage starts. The relationship between SAIDI, SAIFI and CAIDI can be seen in **Figures 11 and 12** at the end of this section, which show SAIFI and CAIDI plotted against one another with dotted lines representing constant SAIDI values. These graphs show that high SAIDI scores can be driven by SAIFI, CAIDI, or both. In **Figure 11** California and Michigan's relatively high SAIDI scores are driven more by CAIDI (long outages) than by SAIFI (frequent outages). The reverse is true of Louisiana and Mississippi.

Beginning in 2013, the EIA began collecting annual reports of SAIDI, SAIFI, and CAIDI from utilities and publishing those data in annual compilations. These data are collected on form EIA-861 and may be downloaded here. The latest available reliability data from EIA are for calendar year 2019. The EIA collects SAIDI and SAIFI metrics with and without Major Event Days (MED). MED are often the result of ice storms, windstorms, wildfires, and hurricanes, and can materially affect annual reliability statistics. While reliability metrics that include MED can fluctuate greatly year-to-year, they provide a more accurate representation of customer experience than metrics excluding MED. For this reason, reliability data are presented with and without MED.

When looking at the figures in this report it is worth understanding that MED are a statistical classification, defined by the IEEE as any day on which more than 10% of utility customers are without power. The result of this hard threshold is that sometimes reliability scores without MED may, in fact, be driven by major events. If recovery from a storm lasts multiple days, the day/s toward the beginning of that recovery may be considered MED because over 10% of utility customers are without power, but the day/s towards the end of the recovery may not be considered MED because fewer than 10% of utility of utility customers are without power, even though all the days of outage were caused by the same event.

We computed SAIDI, SAIFI, and CAIDI with and without MED by state using an average of the reporting utilities within each state, weighted by the number of customers served by each utility.

The following table shows Michigan's 2019 performance on each of these standard reliability metrics, with and without MED. In addition, Michigan's rank from worst to best (1=worst, 51=best) among the states, including the District of Columbia, is shown in parenthesis for each metric.

2019 Metric	With Major Event Days	Without Major Event Days
Annual minutes outage per customer (SAIDI)	555 minutes (4th worst)	211 minutes (6th worst)
Annual outages per customer (SAIFI)	1.53 outages (14th worst)	1.16 outages (17th worst)
Average restoration time per outage (CAIDI)	356 minutes (3rd worst)	182 minutes (3rd worst)

Michigan's performance on several reliability measures ranks among the worst performing states. More detailed analysis of the reliability of Michigan's electric utilities compared to that of other states follows.

SAIDI – Average Minutes of Outage per Customer per Year

As can be seen in Figure 2, in 2019 Michigan ranked 4th worst among the states in overall average number of minutes of outage per customer (SAIDI with MED) over the year and 6th worst in number of minutes of outage per customer (SAIDI without MED) over the year.

Annual data from 2013-2019 in Appendix Tables 2 and 3 show that Michigan's performance in SAIDI without MED has remained very high relative to other states over the last seven years, with 2019 being the worst, while SAIDI with MED has ranged from high to very high relative to other states.

Figure 2: 2019 System Average Interruption Duration Index (SAIDI) in Minutes

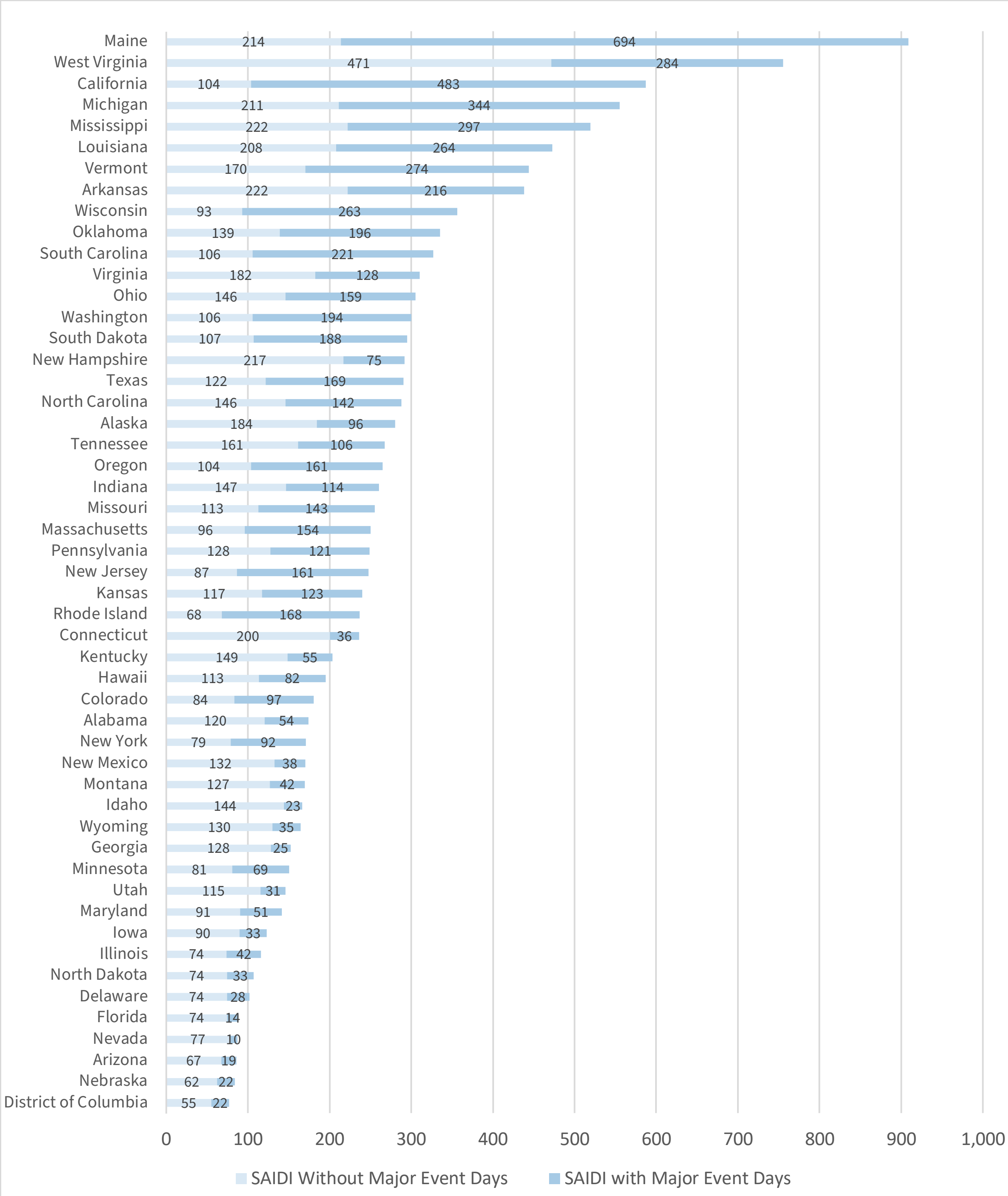


Figure 3: 2019 System Average Interruption Duration Index (SAIDI) with Major Event Days in Minutes

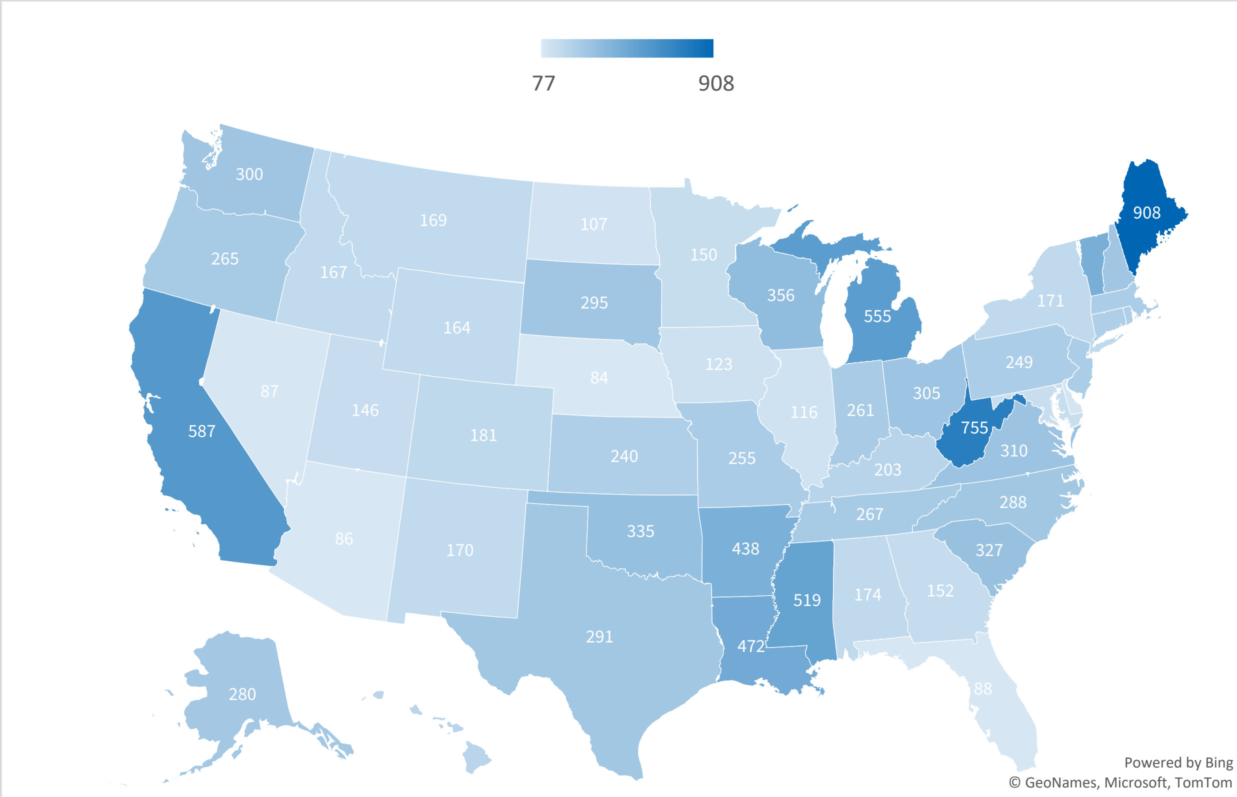
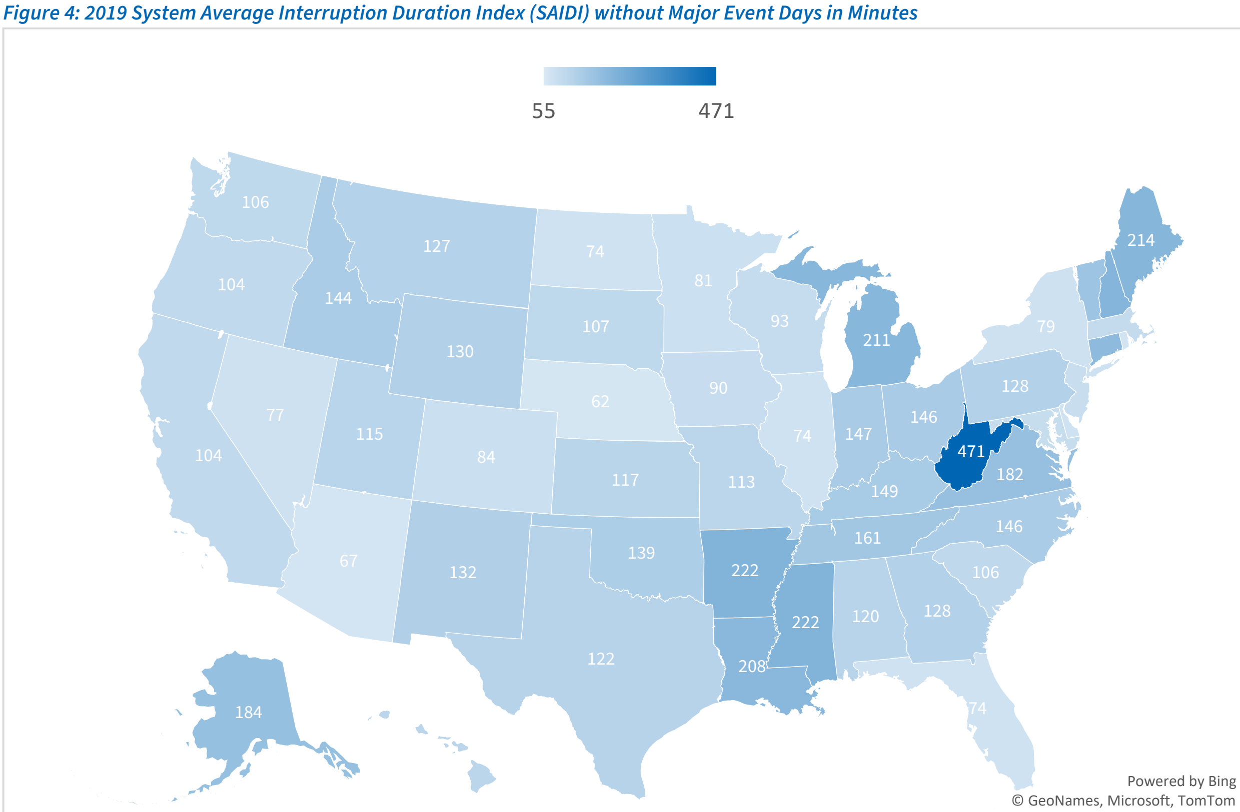


Figure 4: 2019 System Average Interruption Duration Index (SAIDI) without Major Event Days in Minutes



SAIFI – Outages per Customer per Year

Figure 5 shows Michigan's number of outages per customer per year compared to other states, with and without MED. In 2019, Michigan performed relatively poorly in outages per customer (SAIFI with MED), ranking 14th worst overall. When MED are excluded, Michigan average ranking is 17th worst overall. Michigan performed worse than its peer states Illinois and Wisconsin, with only Ohio and Indiana customers experiencing similar numbers of outages per customer per year (Figures 6 and 7).

Figure 5: 2019 System Average Interruption Frequency Index (SAIFI) in Number of Power Outages per Customer

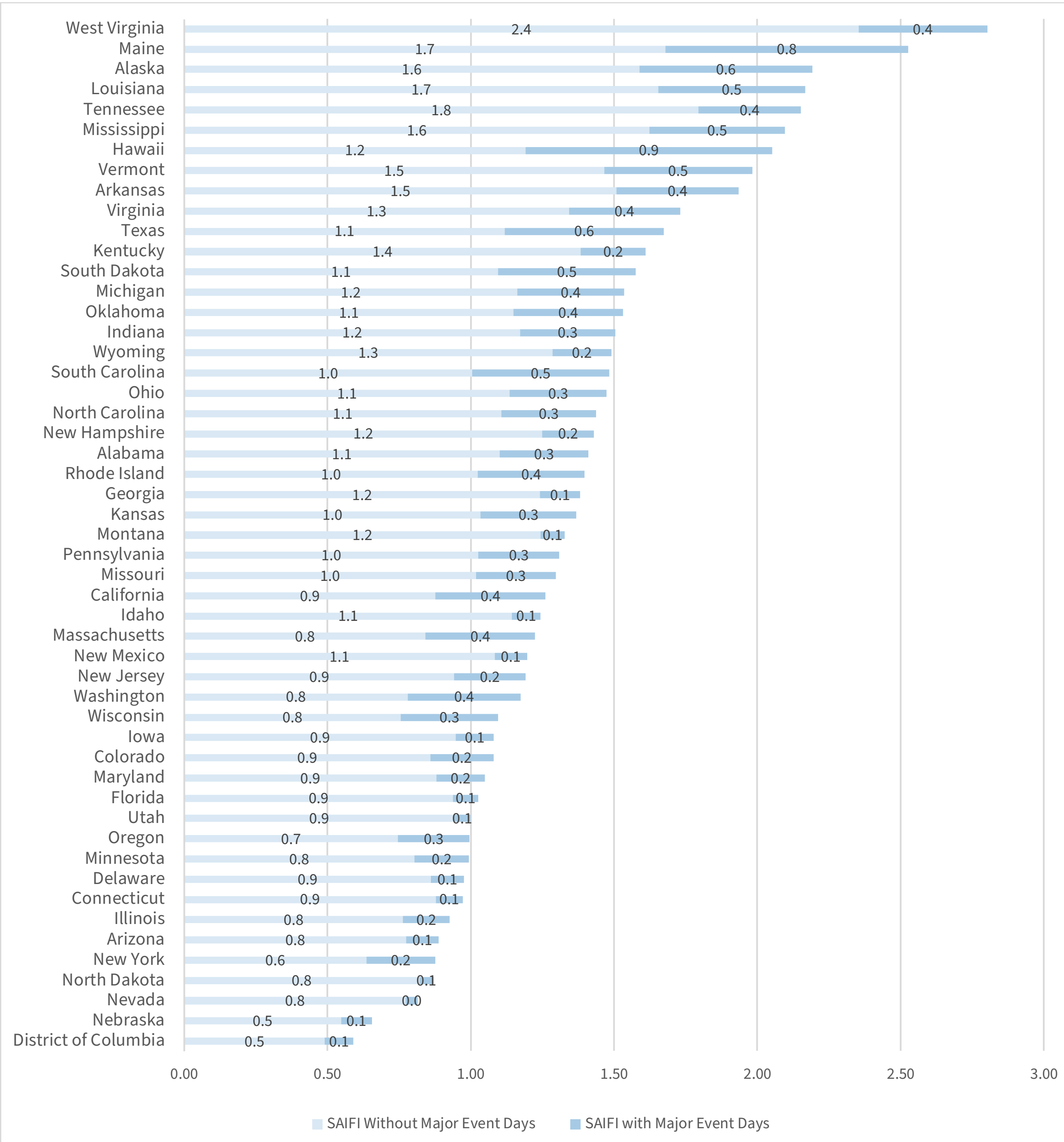


Figure 6: 2019 System Average Interruption Frequency Index (SAIFI) with Major Event Days in Number of Power Outages per Customer

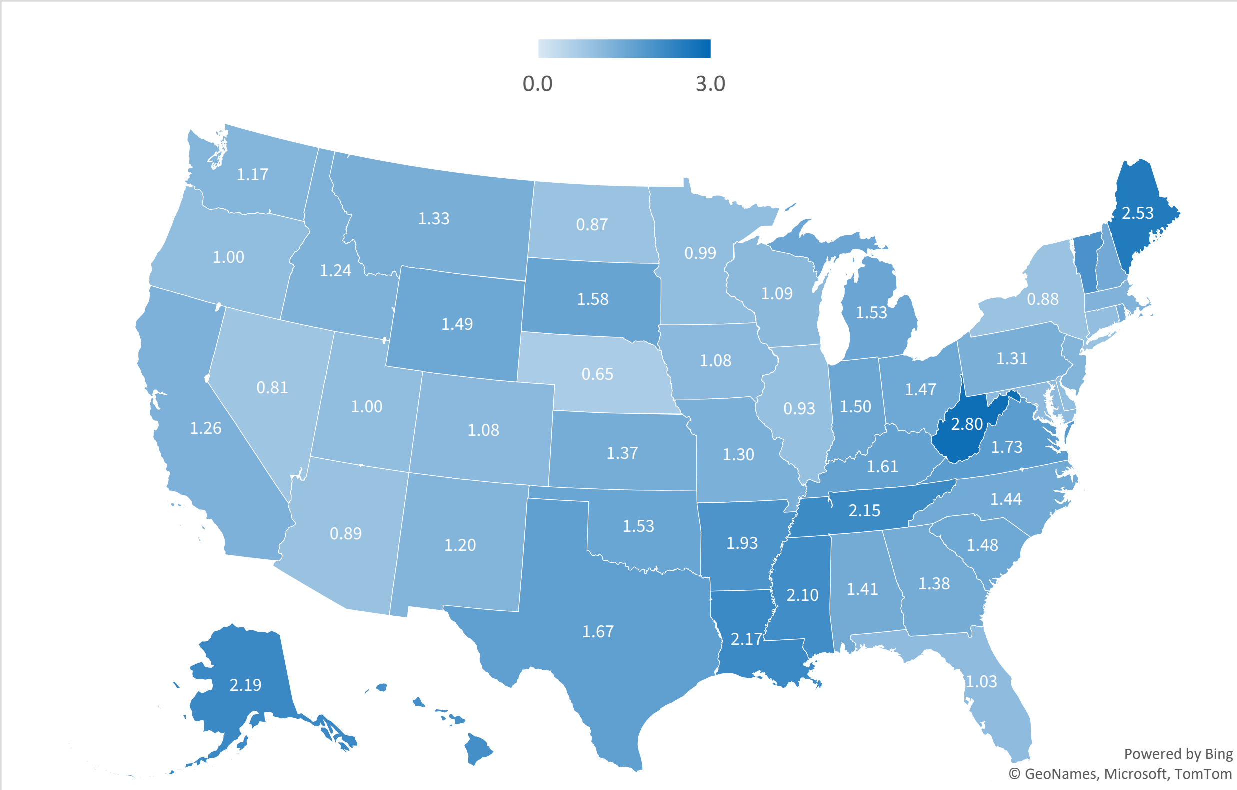
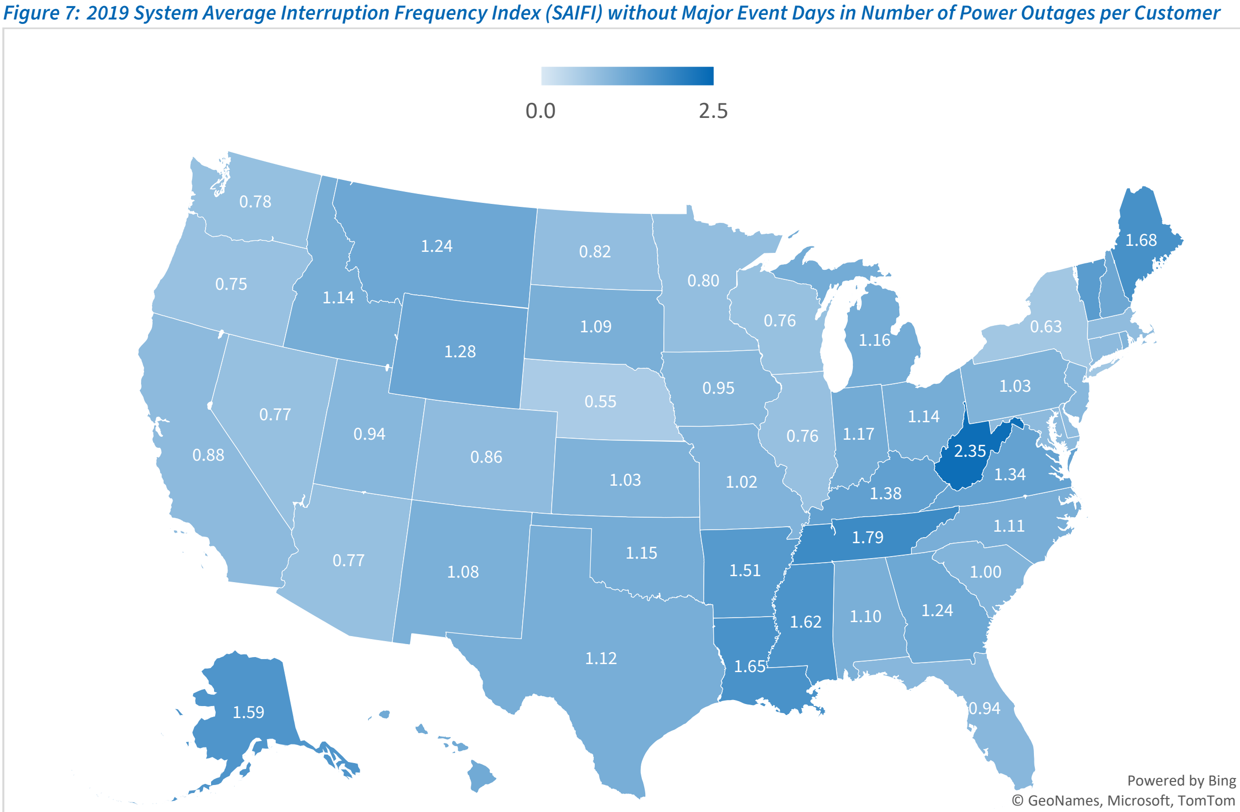


Figure 7: 2019 System Average Interruption Frequency Index (SAIFI) without Major Event Days in Number of Power Outages per Customer



CAIDI – Average Minutes to Restore Power to a Customer

Michigan's poor performance on annual outage minutes per customer (SAIDI) and average performance on the number of outages per customer per year (SAIFI) reflects that the length of Michigan's power restoration time following an outage (CAIDI) is among the worst in the country, with and without MED. In 2019, Michigan ranked 3rd worst in CAIDI with MED and 3rd worst without MED (**Figure 8**).

Appendix Table 4 shows no significant improvement in Michigan's CAIDI with MED and **Appendix Table 5** shows modest improvement in Michigan's CAIDI without MED, suggesting marginal improvements in system reliability during "normal" business conditions, but a persistent susceptibility to extreme or unplanned events.

Figure 8: 2019 Customer Average Interruption Duration Index (CAIDI) in Minutes

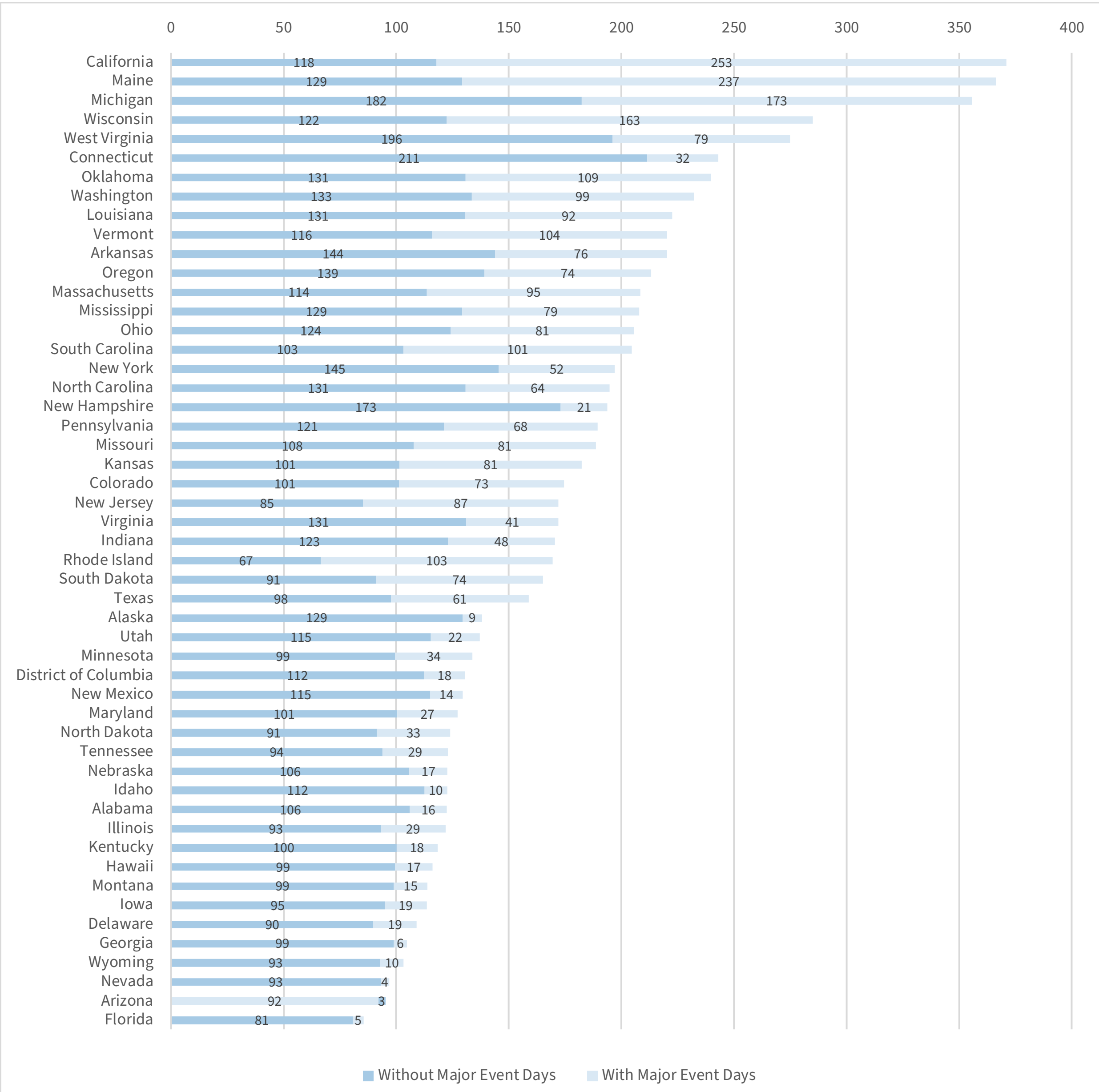


Figure 9: Customer Average Interruption Duration Index (CAIDI) with Major Event Days in Minutes

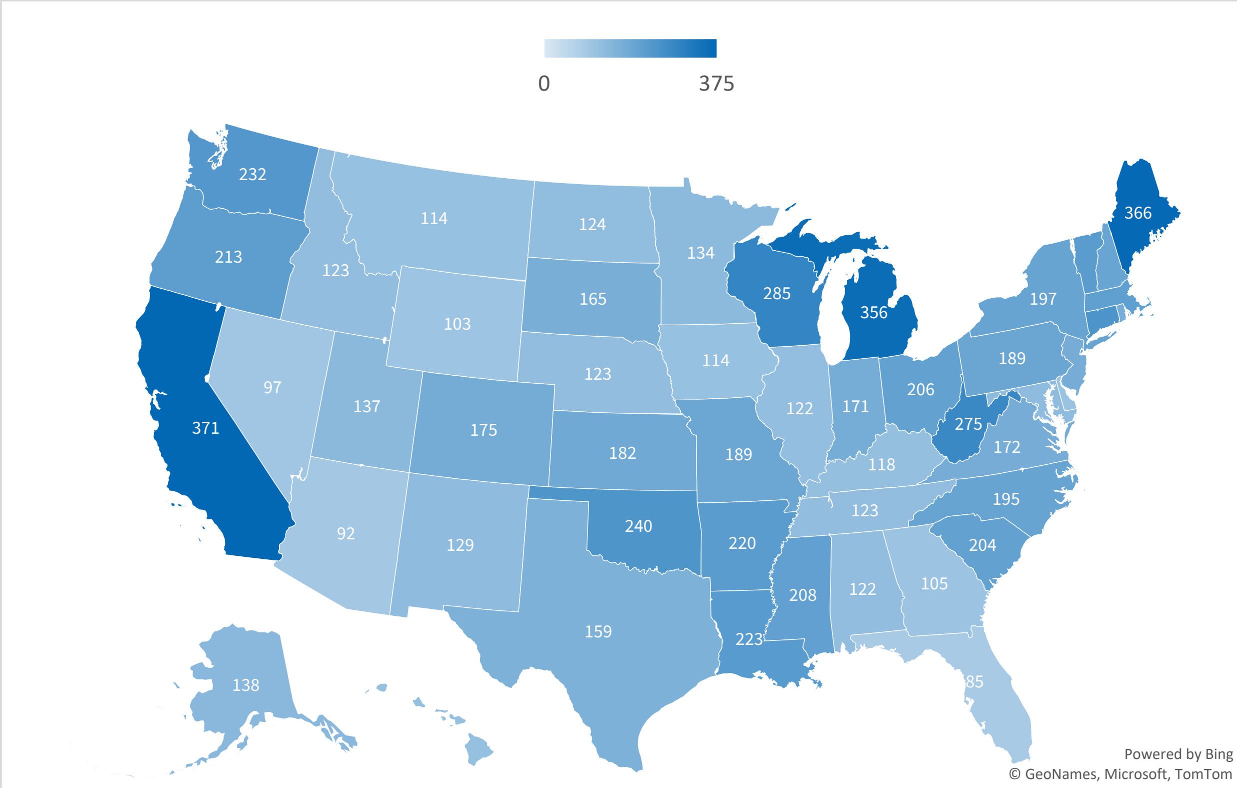


Figure 10: Customer Average Interruption Duration Index (CAIDI)

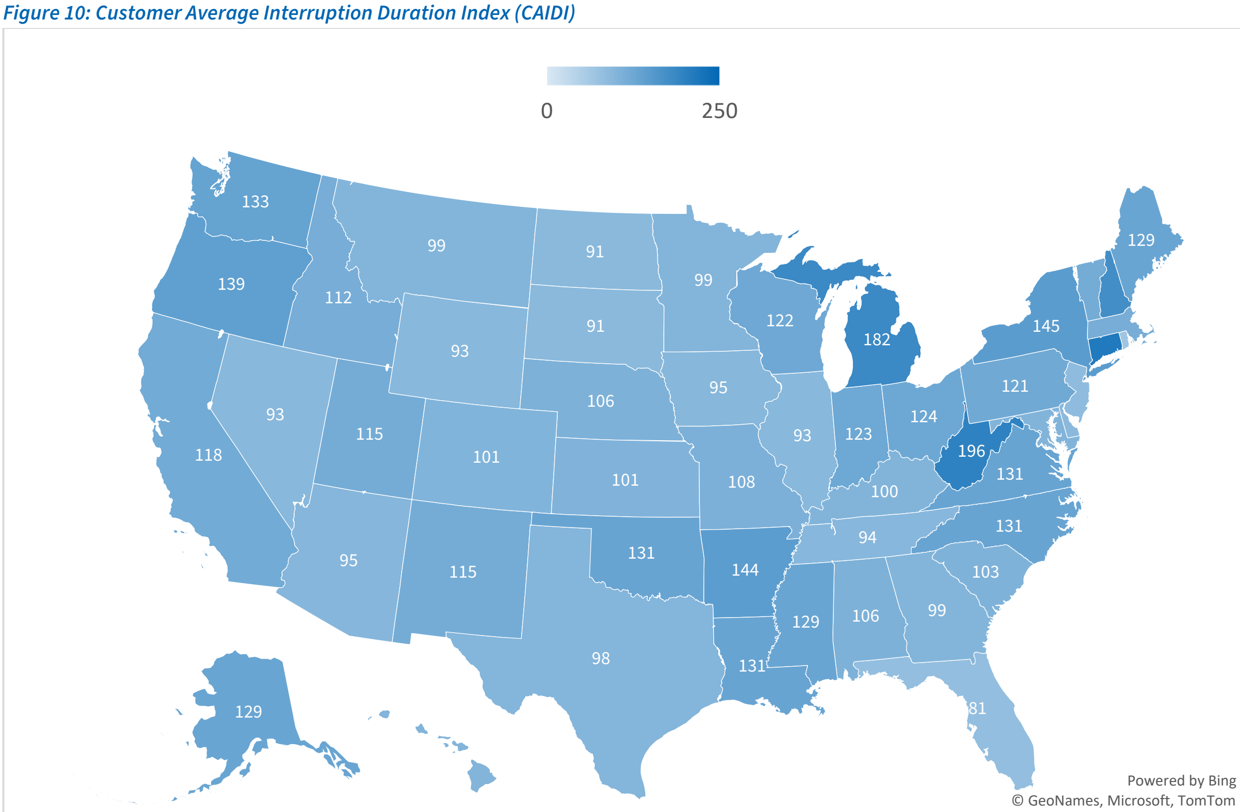


Figure 11: 2019 SAIFI vs. CAIDI with Major Event Days

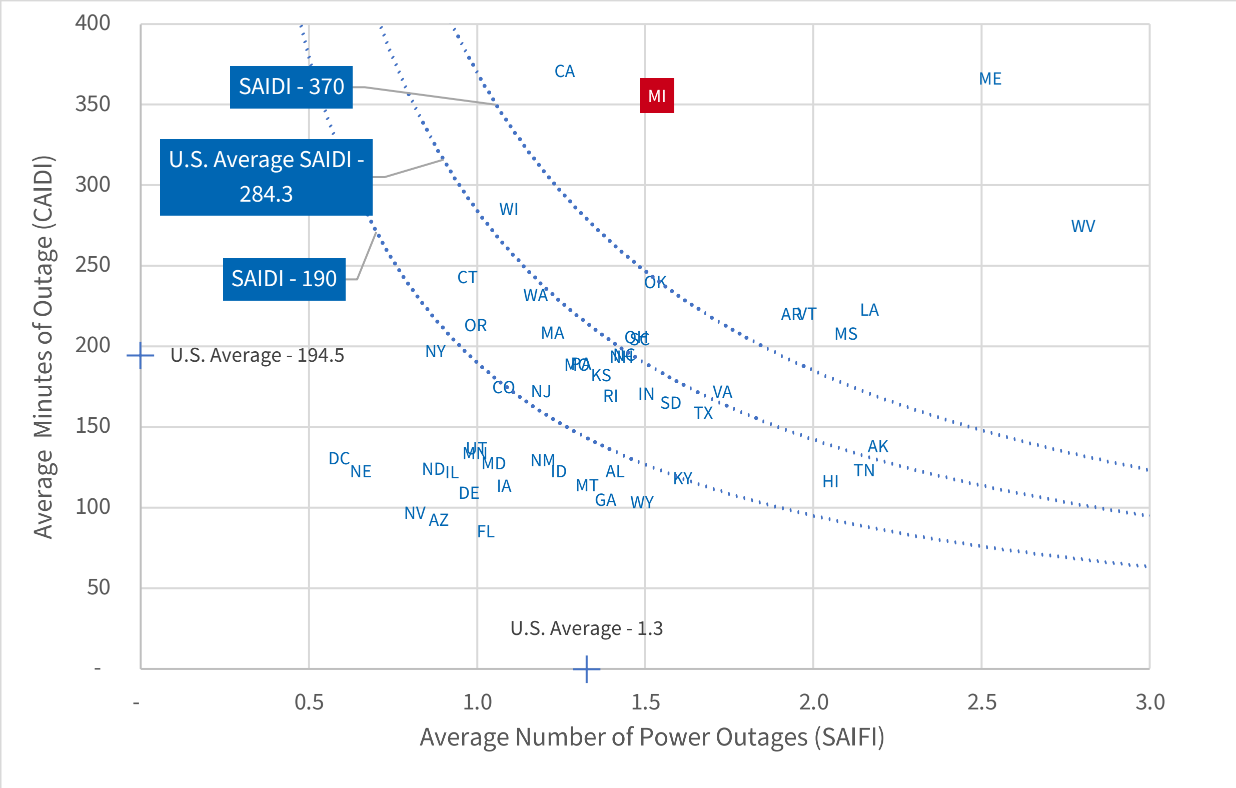
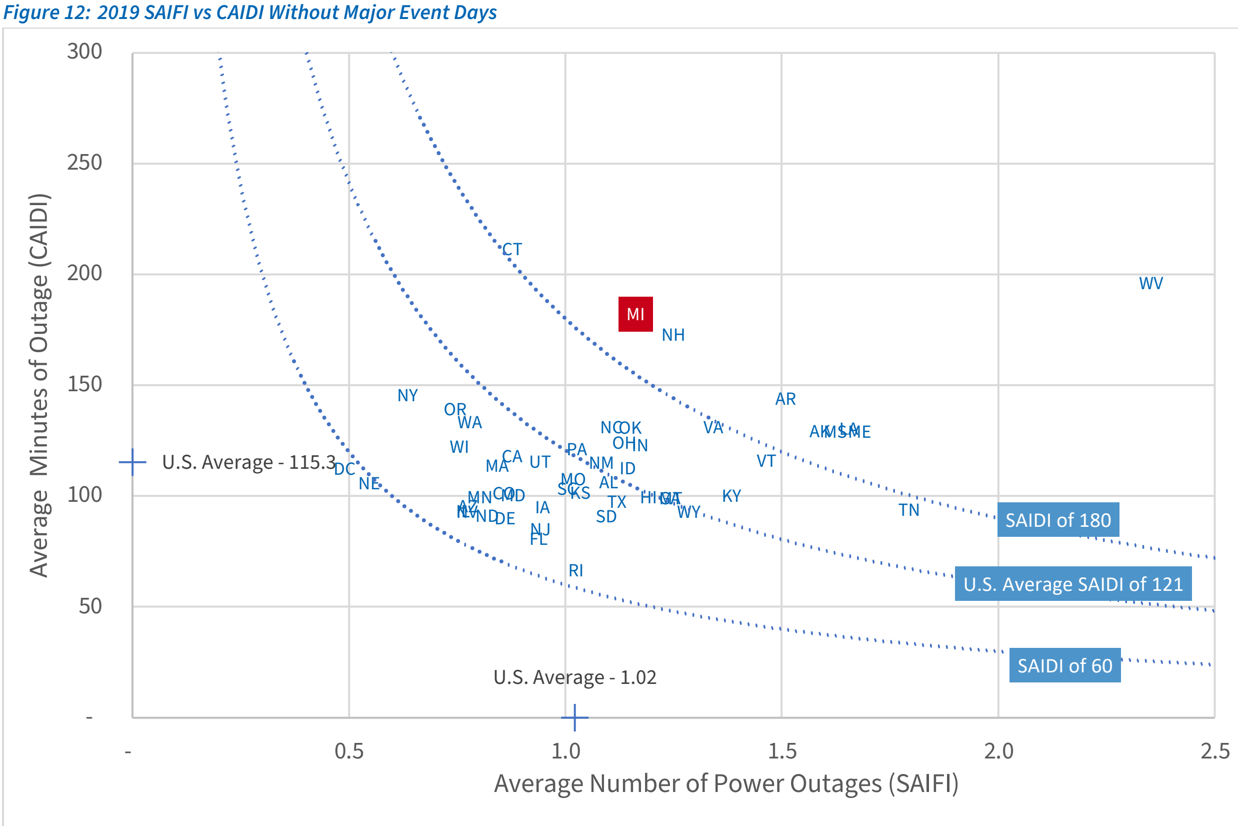


Figure 12: 2019 SAIFI vs CAIDI Without Major Event Days



Michigan Electric Utility Performance

Types of Utilities

There are some trends in Michigan utilities' reliability figures. Electric co-ops are the least reliable utilities in Michigan and municipal utilities are the most reliable, with IOUs landing somewhere in between.

The causes of these trends are reasonably clear. Michigan's cooperative utilities serve predominantly rural areas and include many miles of distribution lines to serve comparatively few customers. These lines are almost always above ground and are exposed to weather and tree damage. Conversely, Michigan's municipal utilities serve the discrete boundaries of cities or towns, have lower total mileage of distribution lines and may have some of these lines buried, thus they are less susceptible to the weather and tree damage that plague the co-ops' lines. Michigan's IOUs serve a mix of areas and are thus subject to both sets of conditions in differing measures.

Figure 13: 2019 System Average Interruption Duration Index (SAIDI) in Minutes for Michigan Utilities

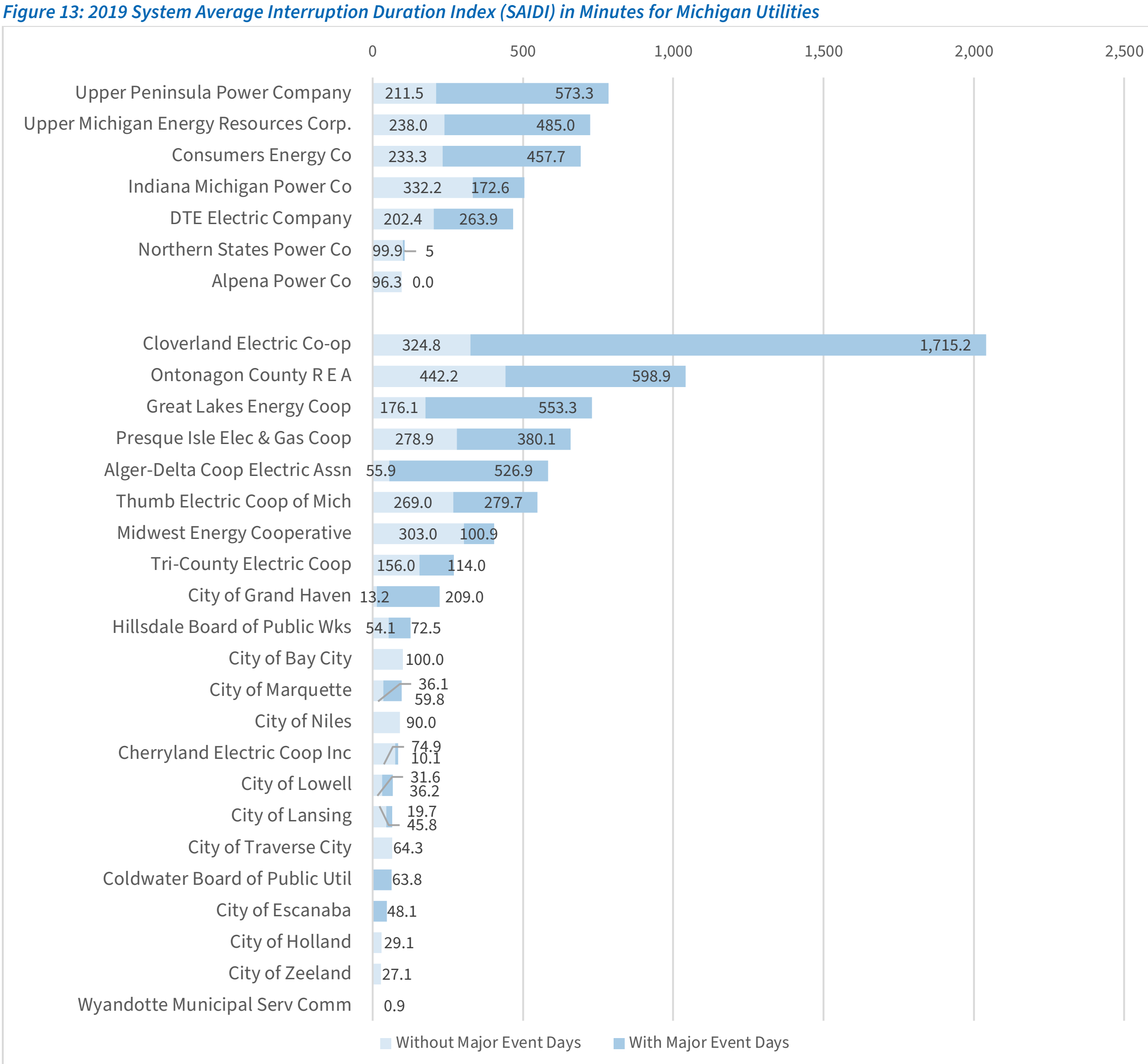


Figure 14: 2019 Customer Average Interruption Duration Index (CAIDI) in Minutes for Michigan Utilities

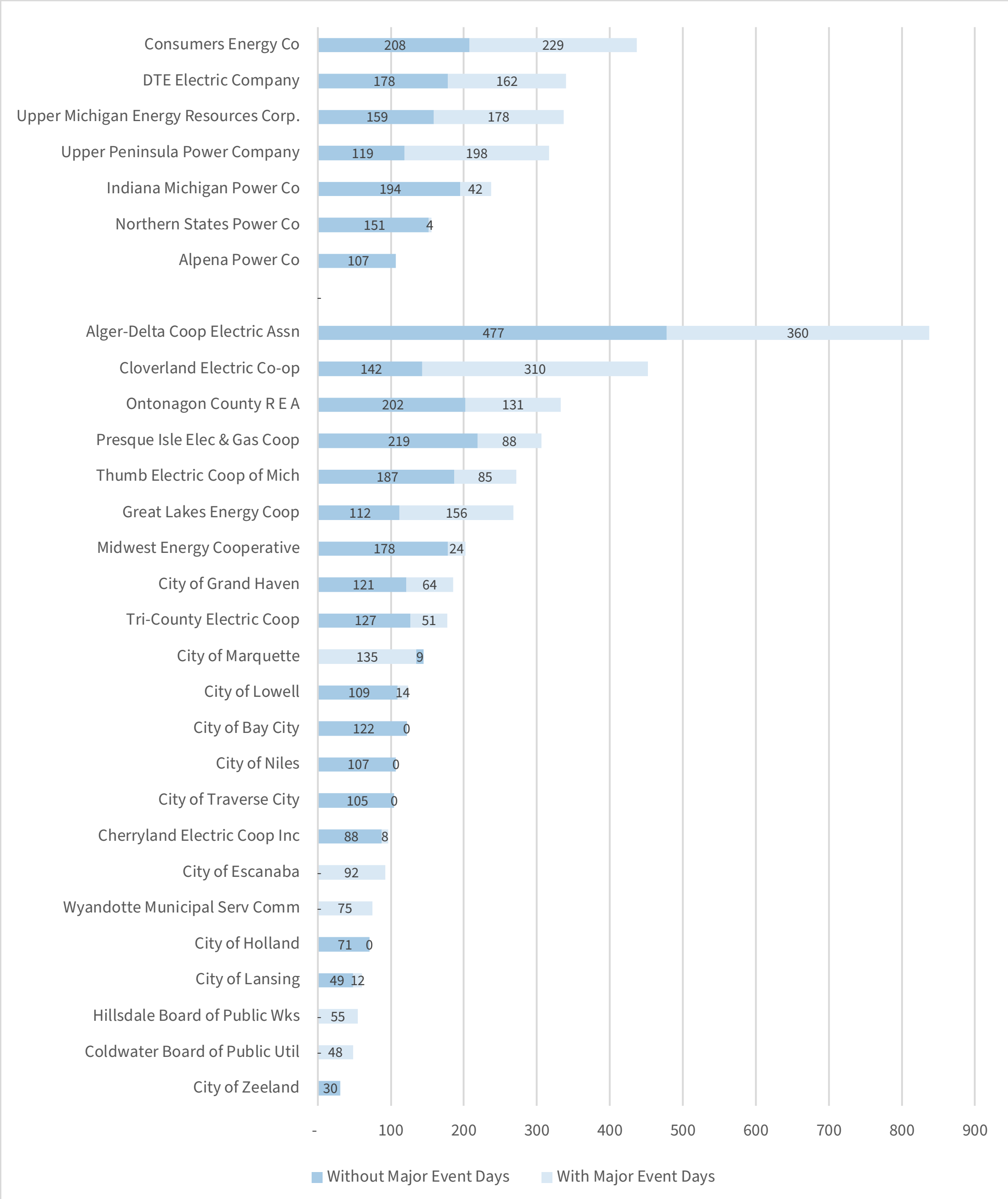
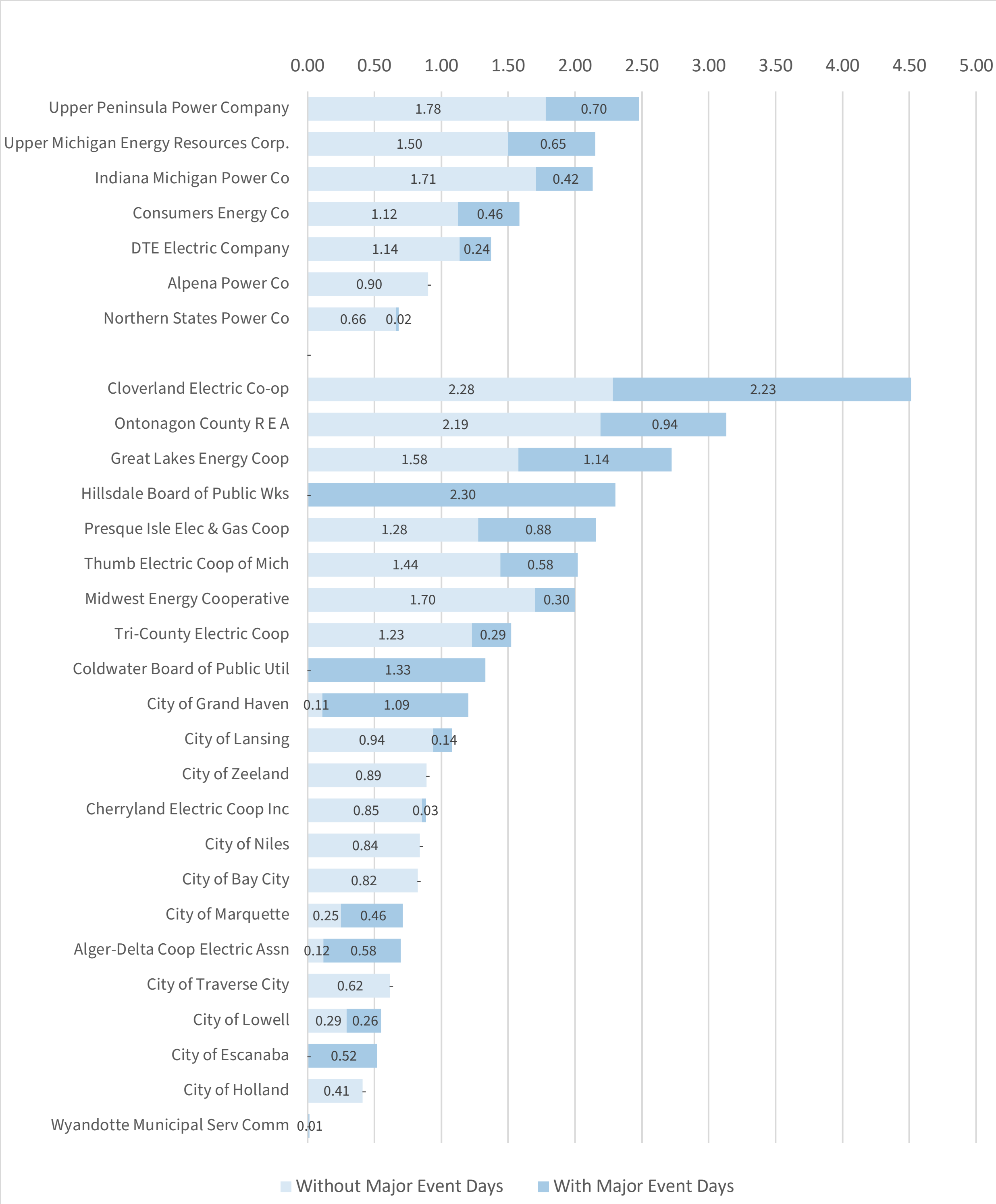


Figure 15: 2019 System Average Frequency Interruption Index (SAIFI) in Number of Outages for Michigan Utilities



Gas Utilities Overview

Gas utilities do not record reliability metrics like electric utilities. This dearth of reliability data may be due to our natural gas infrastructure being generally more reliable than our electricity infrastructure since natural gas lines are mostly buried and less likely to be damaged by storms, wildfires, or wildlife.

Furthermore, when natural gas lines are disrupted only slightly, they continue to function. Unless a natural gas line is severed or leaking massively, the system may still be pressurized well enough to fulfill customers' needs, leading to the problem of long-term undetected leaks. These leaks are dangerous because natural gas is highly flammable if ignited and can cause asphyxiation in high concentrations. IN addition, natural gas is a potent greenhouse gas, with a lifetime atmospheric heating capacity 25 times that of carbon dioxide. The section of this report *Emissions from Natural Gas* quantifies the potential greenhouse effects of leaked natural gas.

Natural gas data are collected as part of form EIA-176. This form records total supply, disposition, losses, and unaccounted for gas. Losses are due to pipeline leaks, accidents, damage, thefts, or blow down. Pipeline leaks tend to occur in a utilities' distribution infrastructure—the numerous smaller pipes that run to homes and businesses. Unaccounted-for gas is the difference between the total supply and the total disposition (accounting for consumption, deliveries, or losses). Sources of unaccounted-for gas could be recording errors or physical losses not included in the previous list.

Unaccounted-for natural gas can take on positive or negative values, depending on the difference between total supply and total disposition, with a negative value implying more gas was delivered than a utility accounted for purchasing or producing.

Figure 18 shows natural gas losses as a percentage of sales as an indication of gas utility reliability. This is a useful statistic, but it is imperfect, because states that produce natural gas for export may show leaks from their production and export infrastructure as losses, thus skewing the ratio of losses to in-state sales and absorbing some of the losses that could be attributable to the states that import their natural gas.

Losses

As shown in Figure 16, Michigan recorded the 5th highest amount of natural gas losses. As a percentage of total sales, losses amounted to 1.32%, 9th highest among states in 2019 as shown in Figure 18.

Figure 16: 2019 Lost Natural Gas in Billions of Cubic Feet

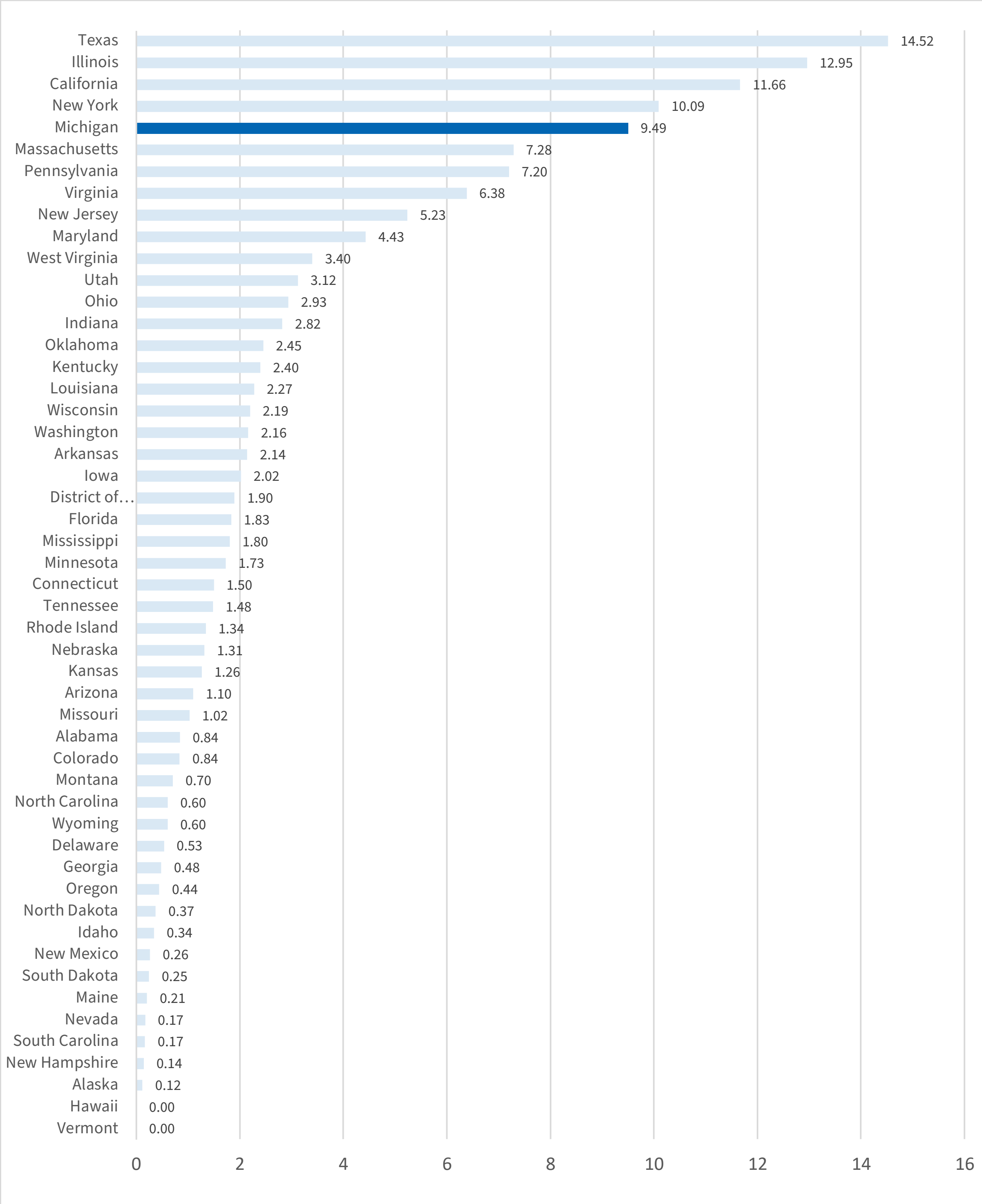


Figure 17: 2019 Lost Natural Gas in Billions of Cubic Feet

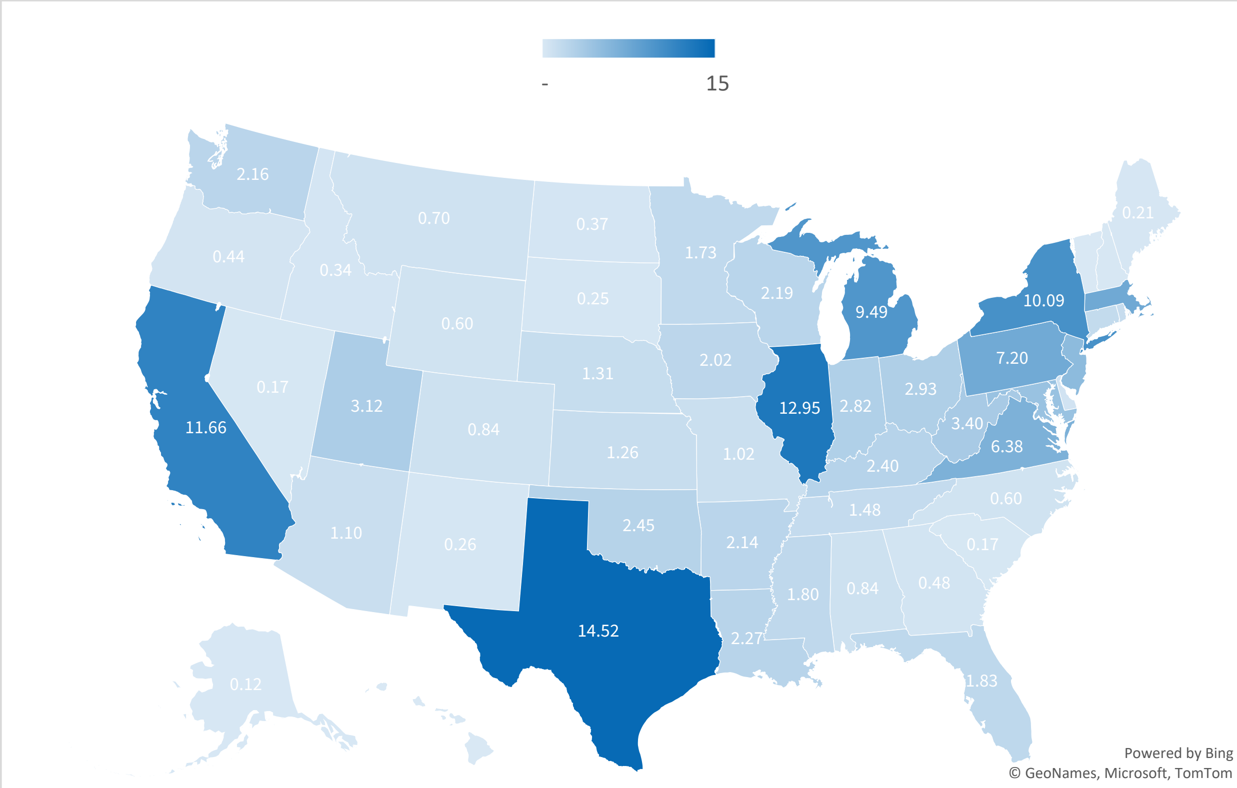
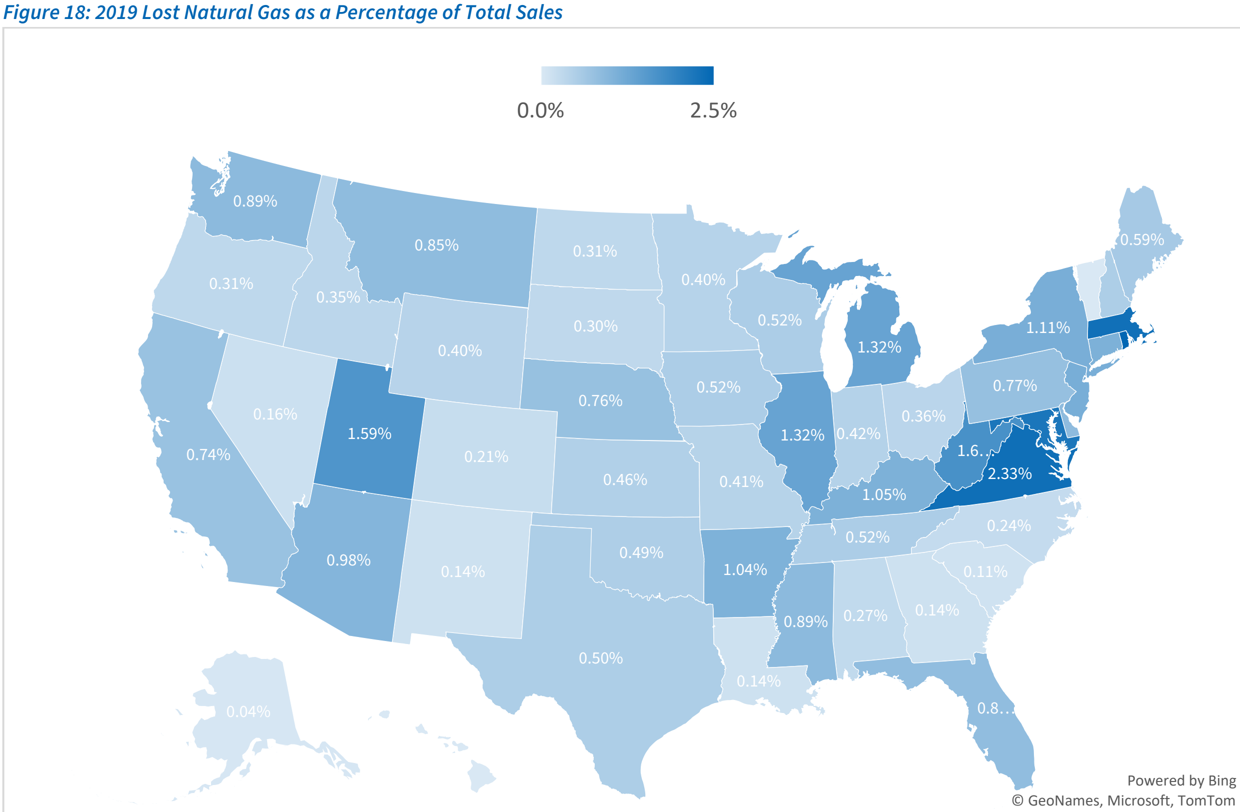


Figure 18: 2019 Lost Natural Gas as a Percentage of Total Sales



Unaccounted

Unaccounted-for natural gas can take on positive or negative values, depending on the difference between total supply and total disposition.

Figure 21 shows unaccounted-for gas amounted to only 0.28% of total sales in Michigan in 2019, ranking 31st in the country. 1,985 million cubic feet were unaccounted-for in Michigan, 20th highest total among the states.

Figure 19: 2019 Unaccounted for Natural Gas in Billions of Cubic Feet

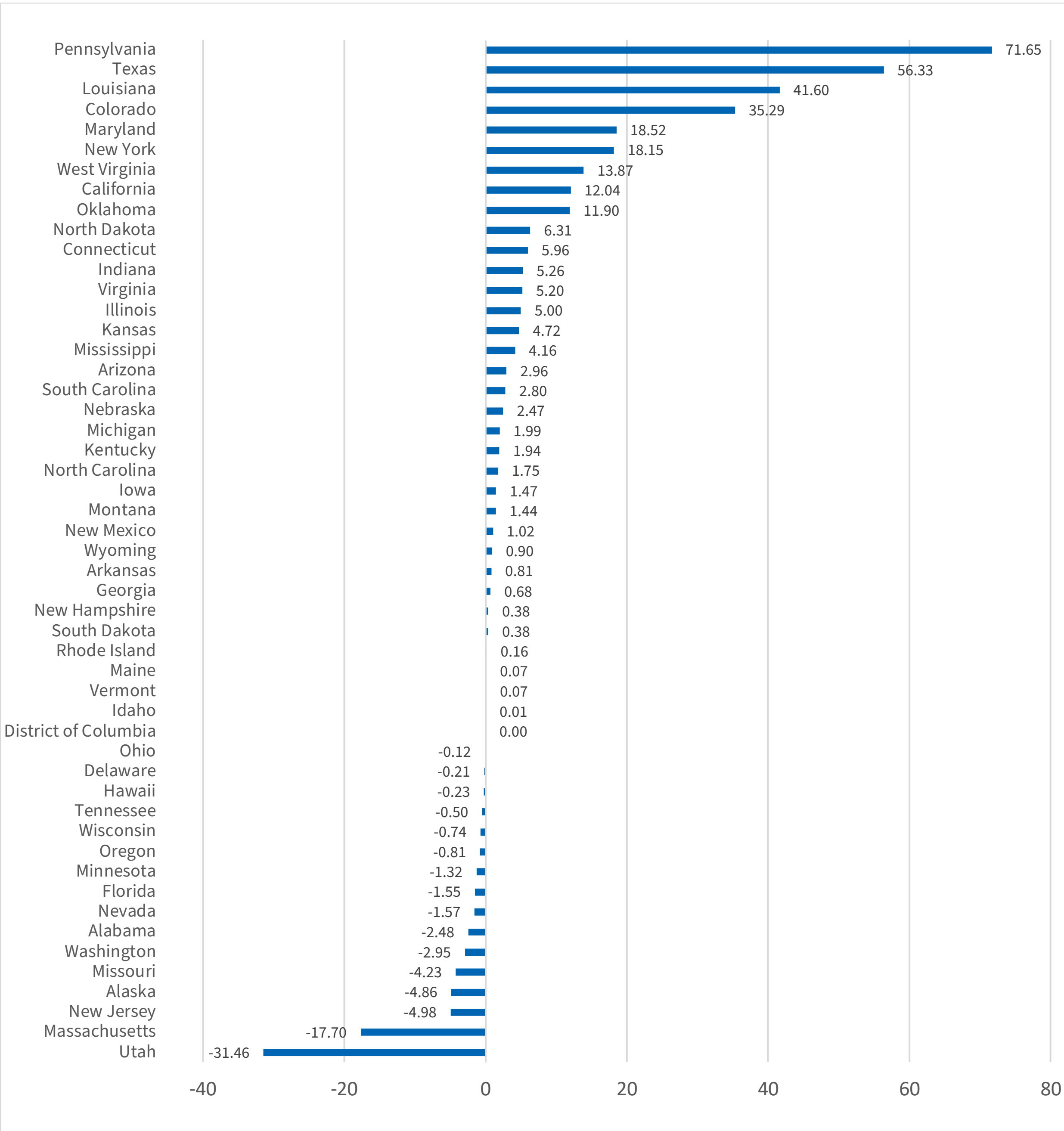


Figure 20: 2019 Unaccounted for Natural Gas in Billions of Cubic Feet

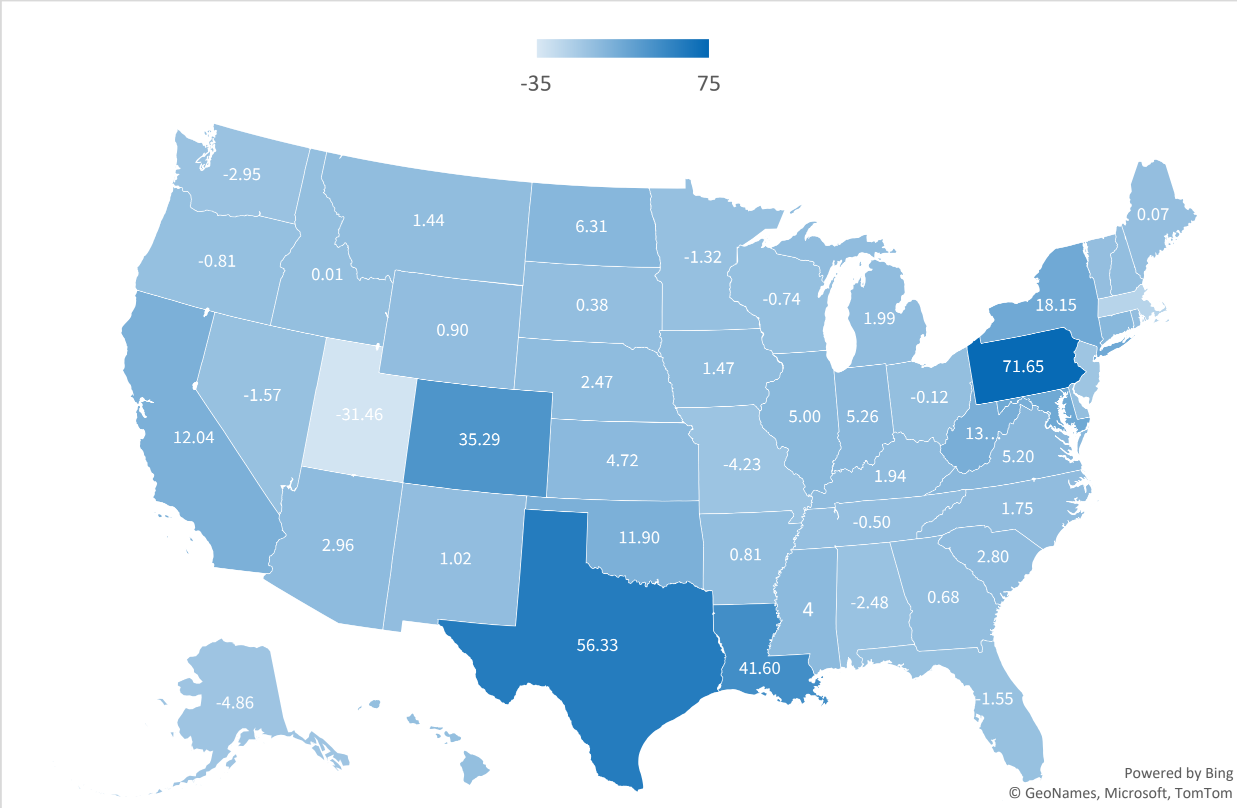
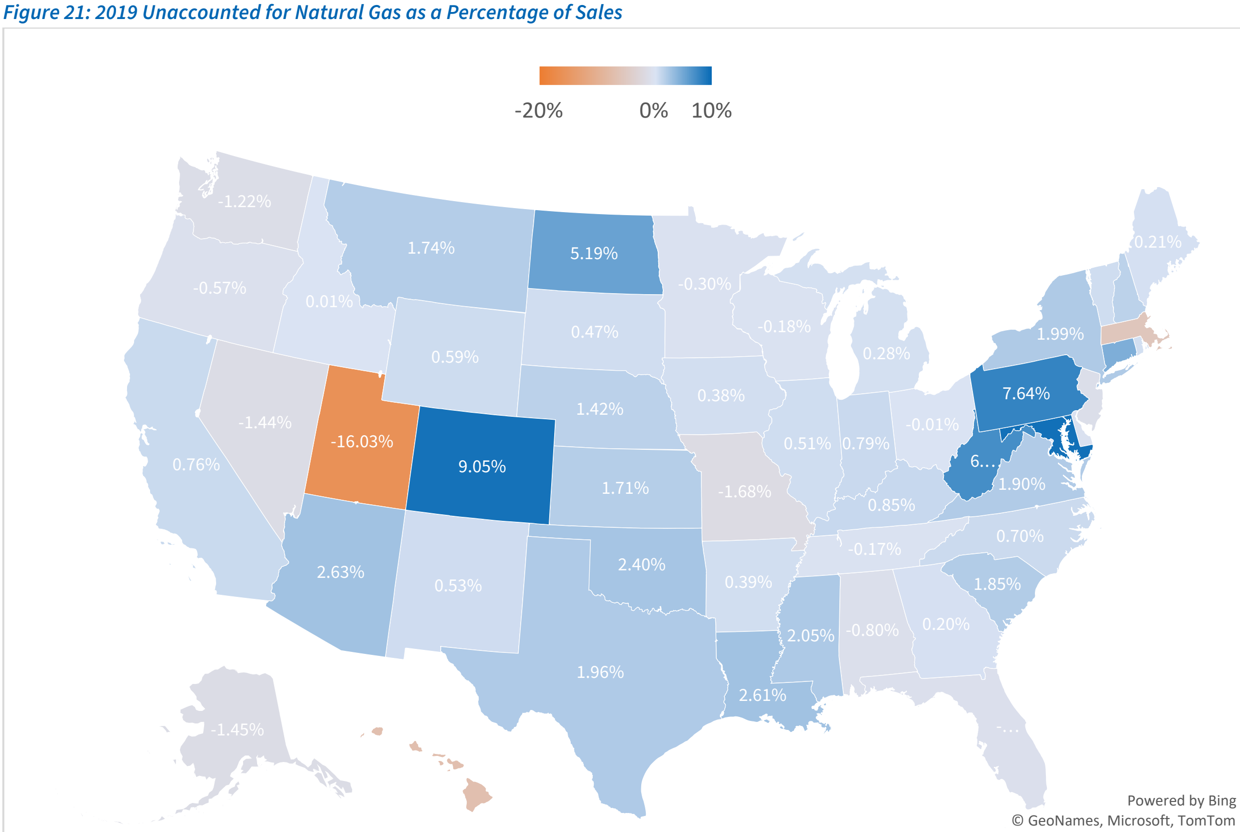


Figure 21: 2019 Unaccounted for Natural Gas as a Percentage of Sales



Michigan Gas Utility Performance

A notable trend in Michigan's gas utility performance can be seen in DTE Energy's and Consumers Energy's relative losses and unaccounted-for natural gas statistics. DTE reports the largest natural gas losses of any Michigan utility by far, but no unaccounted-for natural gas in 2019. In contrast, Consumers reports low levels of lost natural gas, but large amounts of unaccounted-for natural gas. It is possible that Consumers' unaccounted-for natural gas is lost natural gas, but Consumers is doing a worse job of tracking it than DTE. If this were the case, then the major discrepancy between Consumers and DTE in natural gas losses would be much smaller. However, without further research no conclusions can be made definitively.

Figure 22: 2019 Natural Gas Losses in Millions of Cubic Feet

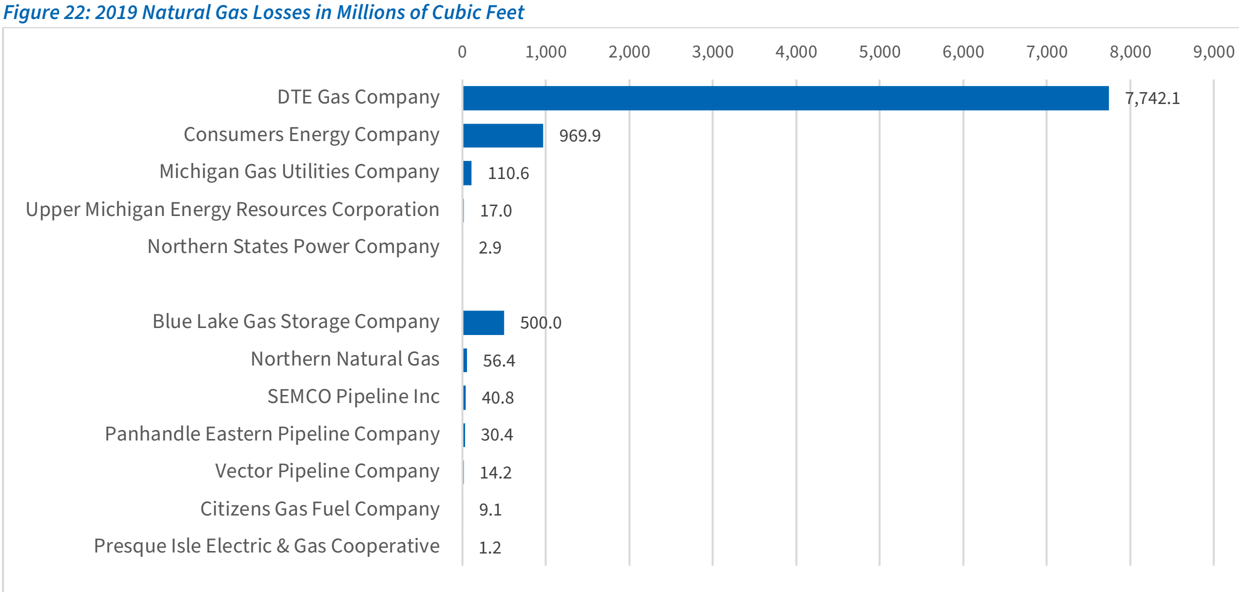
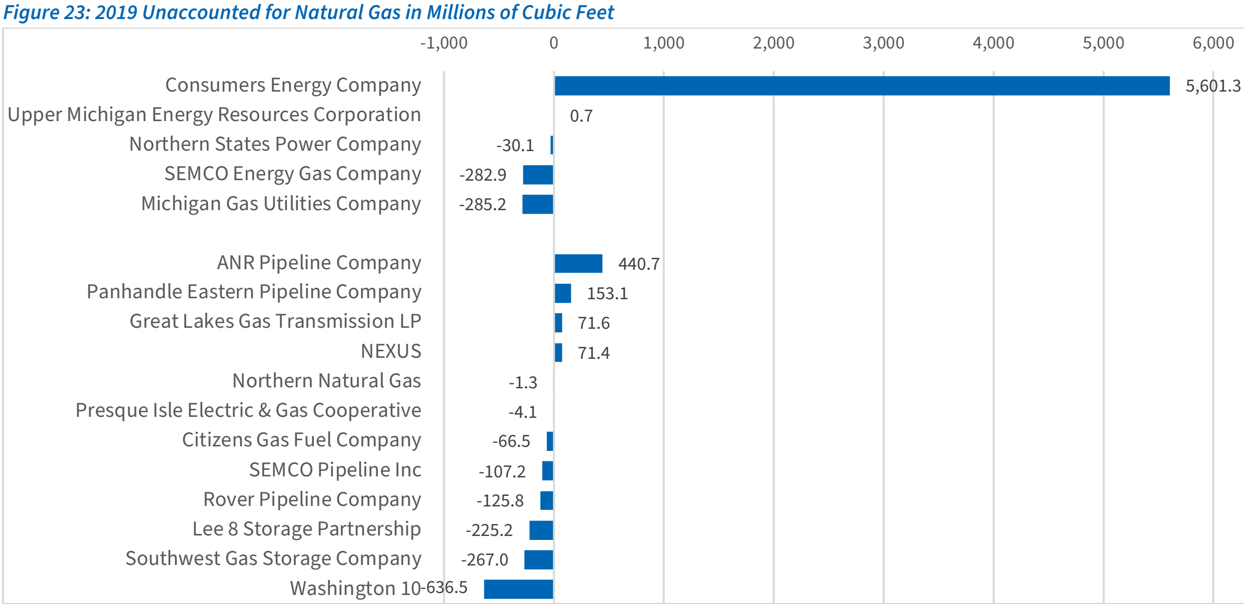


Figure 23: 2019 Unaccounted for Natural Gas in Millions of Cubic Feet



HOUSEHOLD ENERGY

American homes use a variety of forms of energy on a day-to-day basis. Almost every American home has access to electricity, and some homes use electricity as their exclusive source of energy as it is highly adaptable, and can be used for lighting, powering tools and electronics, cooling homes and for household heating through resistance heat, and increasingly through air-source and ground-source heat pumps.

However, many homes have multiple energy sources, the most prevalent of which, after electricity, is natural gas. Natural gas is commonly used for heating homes and water, cooking, and drying clothing. Beyond electricity and natural gas, Americans use a variety of other fuels as sources of heat, including propane, kerosene, fuel oil, wood, and more. Given their relatively limited use compared with electricity and natural gas, this report aggregates all fuel sources other than electricity and natural gas into a category called “other heating fuels.”

The *Household Energy* section of the document is broken down into the following subsections:

- Affordability
- Fuel Sources
- Residential Energy Use
- Residential Electricity Costs and Expenditures
- Residential Natural Gas Costs and Expenditures
- Residential Other Heating Fuel Costs and Expenditures

The chart below shows Michigan’s relative 2019 ranking among the states across the metrics contained in *Household Energy* as well as the actual values of those same metrics in 2019.

Table 2: 2019 Michigan Household Energy Metrics

Metric	2019 Value	2019 Rank
Residential Energy Expenditures	$2,041	16
Residential Energy Expenditures as a Percentage of State Median Household Income	3.18%	19
Percentage of Households Heating with Electricity	10%	48
Percentage of Households Heating with Gas	76%	3
Percentage of Households Heating with Other Heating Fuels	13%	22
Electricity Use per Household (Kilowatt Hours)	7,640	42
Residential Electricity Cost (Dollars per Kilowatt Hour)	$0.16	11
Average Yearly Household Electricity Expenditures	$1,203	39
Natural Gas Use per Household (Therms)	993	3
Residential Natural Gas Cost (Dollars per Therm)	$0.81	39
Average Yearly Household Natural Gas Expenditures	$802	17
Other Heating Fuel Use per Household (MMBTU)	161.7	10
Household Other Heating Fuel Cost (Dollars per MMBTU)	$11.83	40
Average Yearly Household Other Heating Fuels Expenditures	$1,914	16

Affordability

This subsection takes a broad look at energy affordability, which we quantify through the metric of energy expenditures as a percentage of state median income. For these figures, energy expenditures refer to expenditures on all forms of energy combined, which includes electricity, natural gas, and other heating fuels.

The broad trends in affordability show that some of the least affordable states are relatively low-income southern states with high electricity bills for cooling, such as Mississippi, Alabama and Georgia, as well as cold northern states with high fuel costs and use and state median incomes closer to the mean, such as Rhode Island, Vermont, and Maine, which, in 2019 comprise 3 of the top 5 states with the lowest energy affordability in the country (**Figures 24 and 25**).

In 2019 Michigan rated 19th worst on this metric, with the average Michigan household spending 3.18% of its income on energy. In absolute terms, the average Michigan household spent 2,041 dollars on energy, making Michiganders' energy bills the 16th highest in the nation.

Figure 24: 2019 Household Energy Expenditures as a Percentage of Median Income

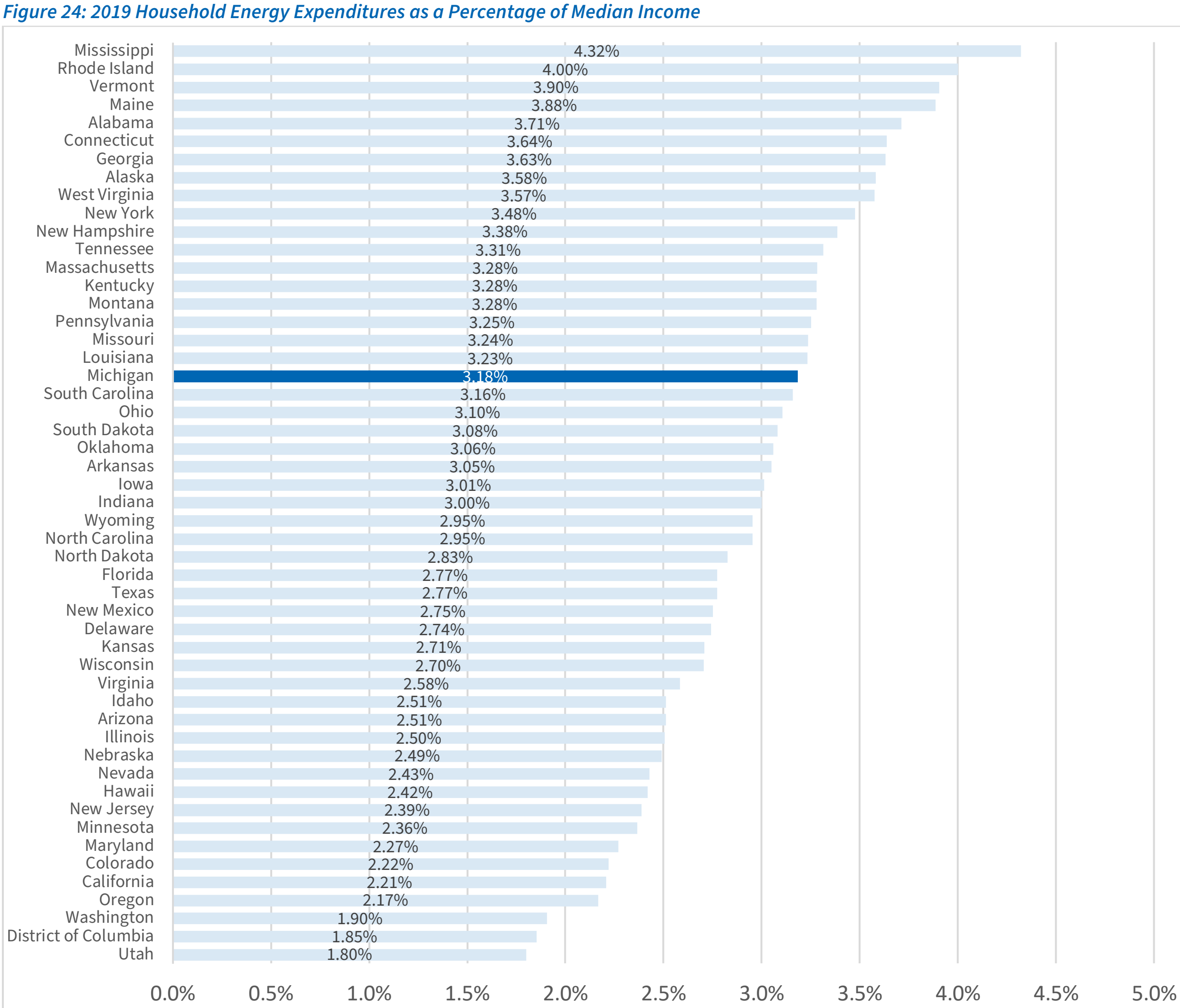


Figure 25: 2019 Household Energy Expenditures

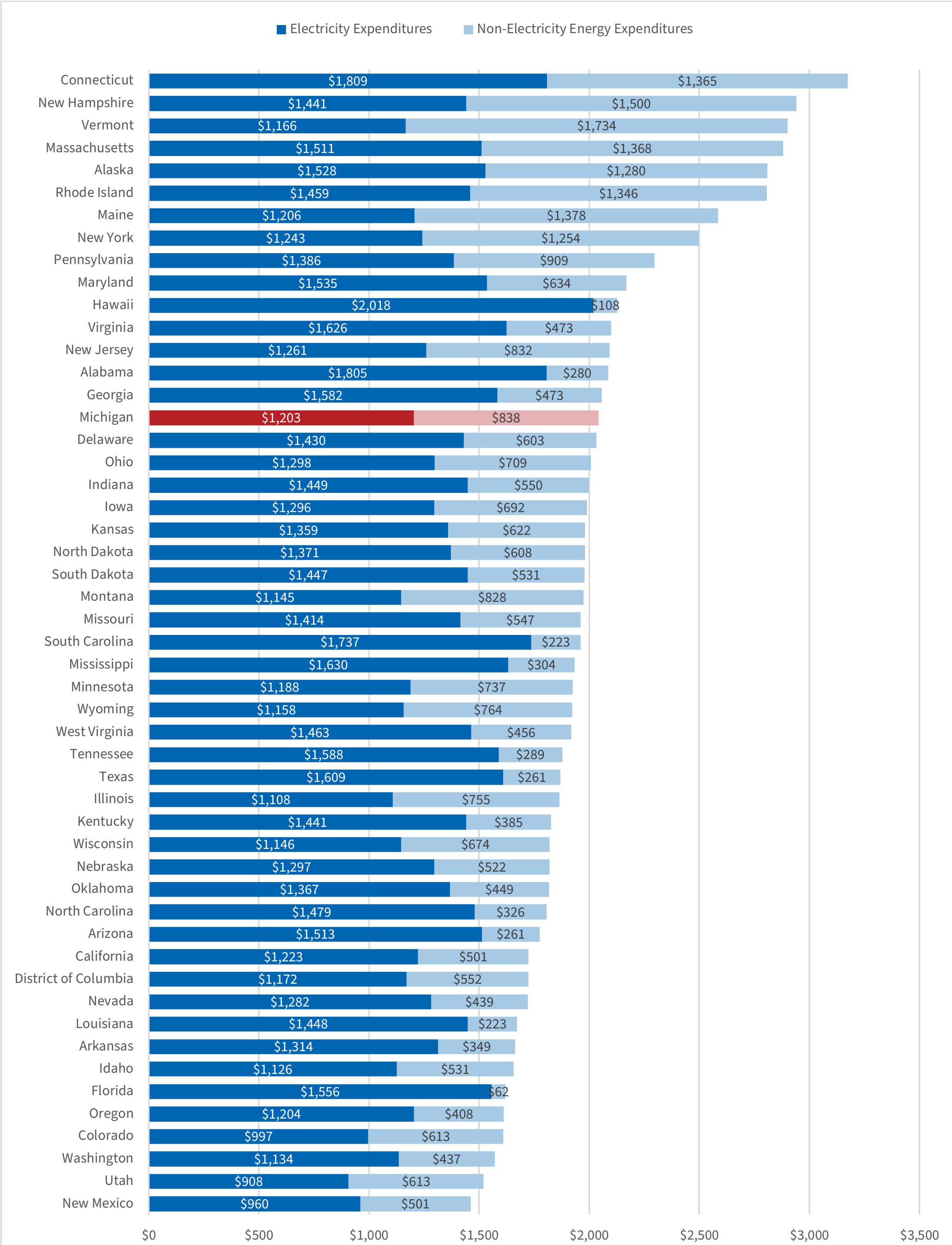


Figure 26: 2019 Household Energy Expenditures as a Percentage of Median Income

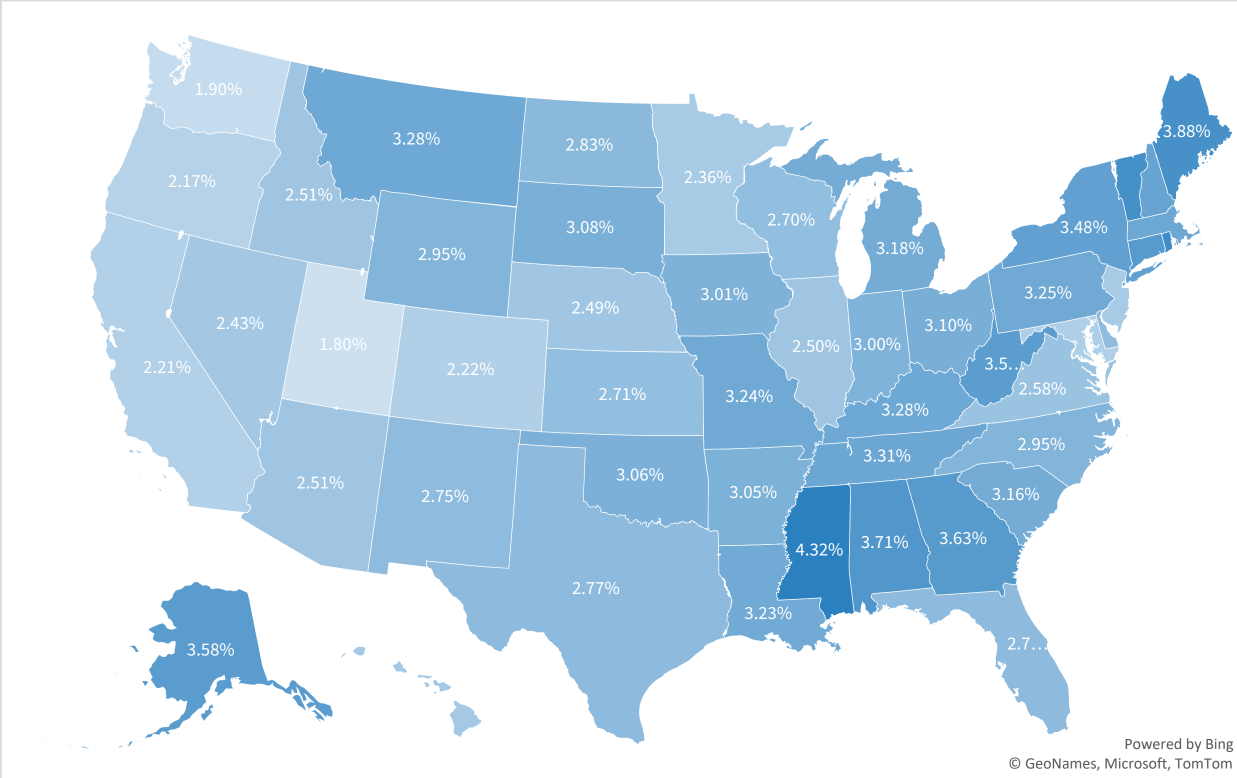


Figure 27: 2019 Household Energy Expenditures

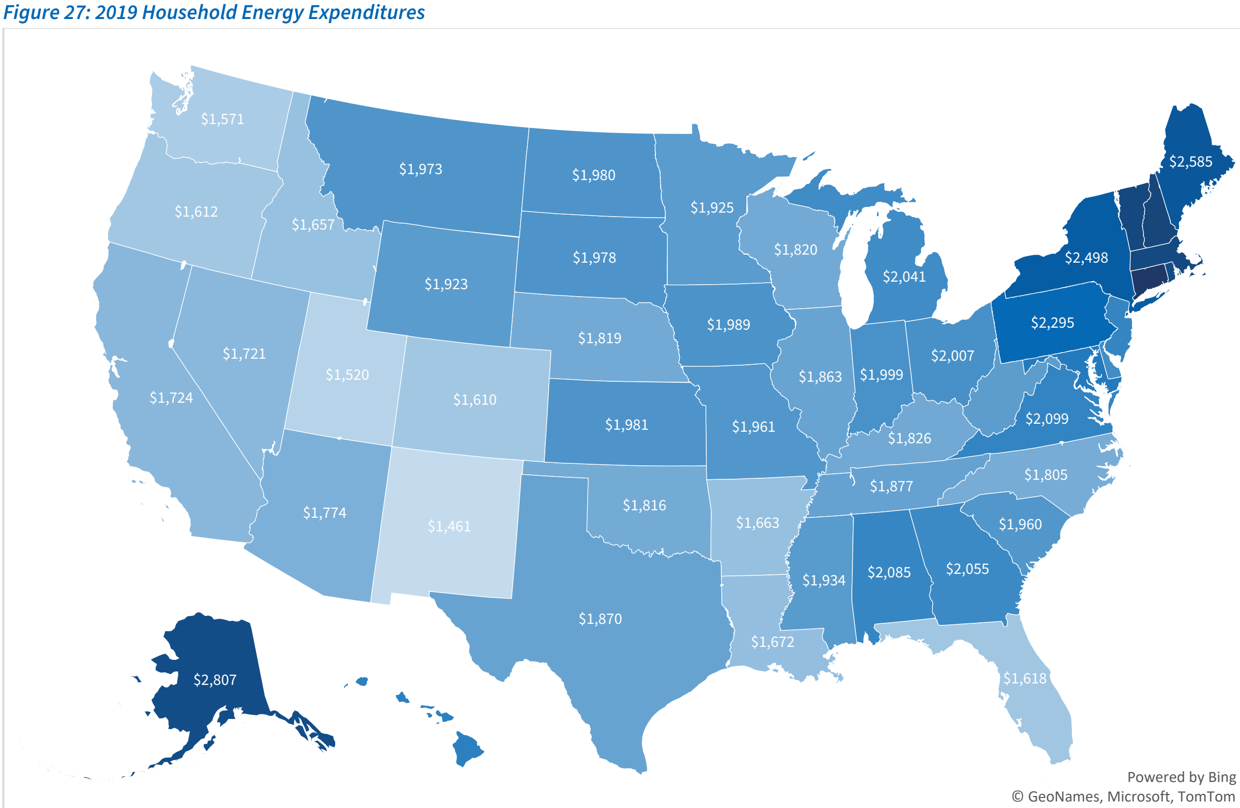


Figure 28: 2019 Energy Expenditures per Household vs. Median Income

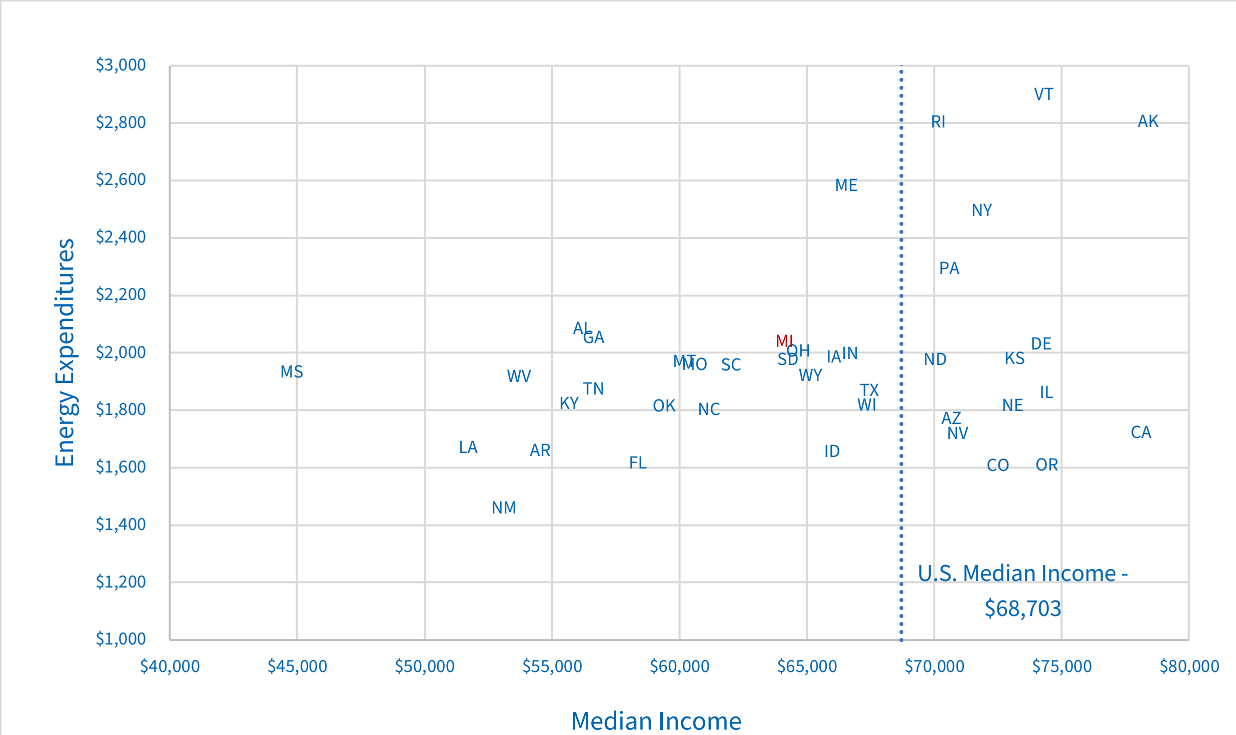
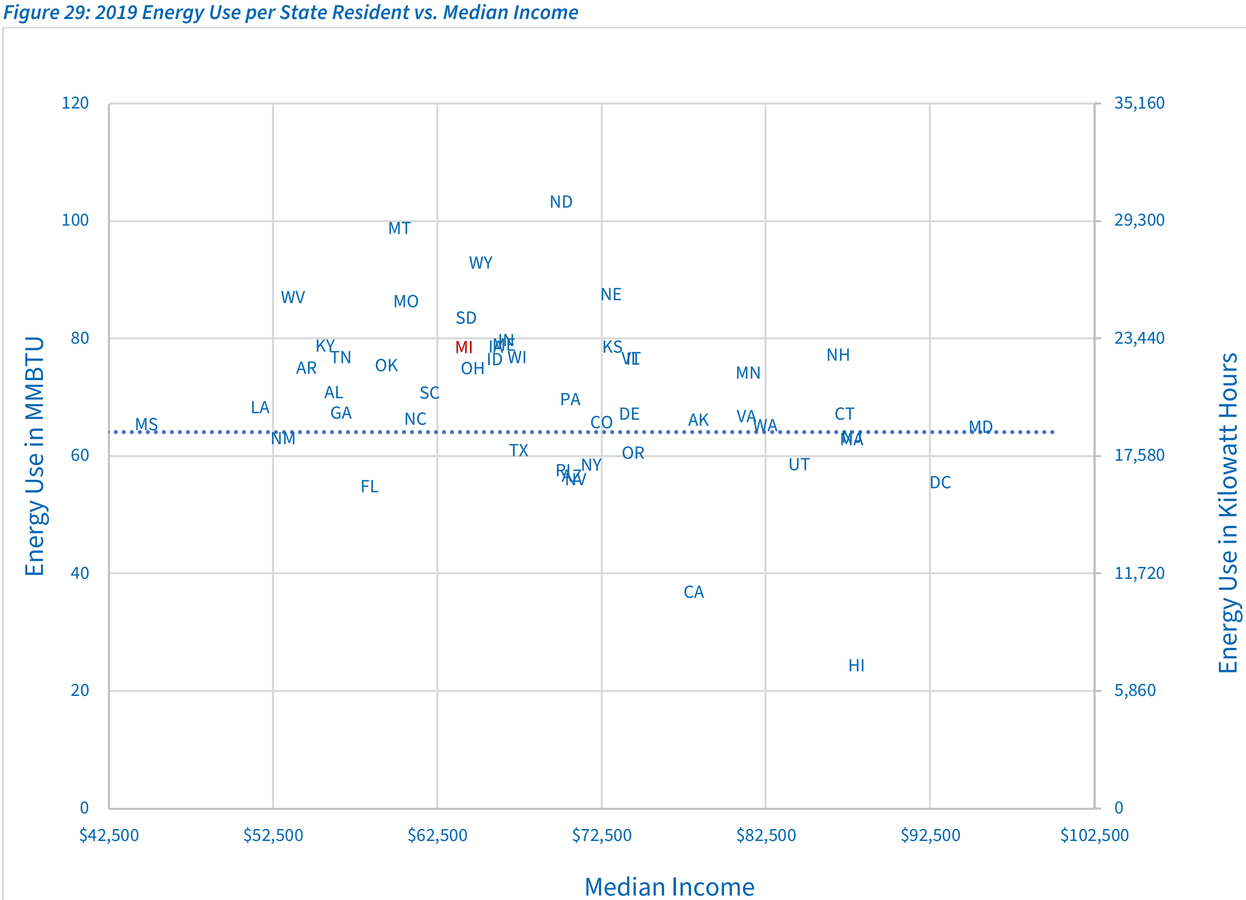


Figure 29: 2019 Energy Use per State Resident vs. Median Income



Heating Fuel Sources

The type of fuel American households use for heat, both for home heating and for other heat uses such as cooking, hot water heating, and clothes drying, is dependent on factors such as geography, average daily temperature, access to infrastructure, and relative fuel costs.

In general, natural gas, and in some places, other heating fuels, are on a cost per energy unit basis more affordable than electricity for producing heat. This trend is beginning to be upended by the increasing accessibility of high-quality, low-temperature, air-source heat pumps, but for the time being, economics support the use of direct heat sources for household heating. Thus, colder, northern states are unlikely to heat with electricity, whereas southern states are generally content to use resistance electric heat for the comparatively rare occasions where home heating is necessary, as there is a financial incentive to avoid the need for a furnace and gas or other heating fuel hookup.

Access to infrastructure, however, also drives the choice of heating fuel sources. For instance, access to natural gas distribution is a product of population density and the age of a state's infrastructure and housing stock. Given North Dakota's cold climate, one might reasonably expect that homes would heat with natural gas or other heating fuels, but a surprising 41% of North Dakotans heat with electricity (**Figure 32**), and fewer than half heat with natural gas, whereas nearby Minnesota has a 66% penetration of natural gas heating and a mere 17% of Minnesotans heat with electricity (**Figures 32 and 33**). This phenomenon appears to be the product of relatively low population density in North Dakota compared to Minnesota, which has some major urban centers, making the development of natural gas infrastructure in North Dakota uneconomical for natural gas distributors.

The Northeastern US shows very few homes heating with electricity but a high penetration of other heating fuels (**Figures 32 and 34**). This trend is less the product of low-population density, as these Northeastern states are some of the densest, and more the product of older housing stock and infrastructure.

Most of the data in this subsection come from the EIA, but data on which fuel sources are used for home heating come from the United States Census Bureau, specifically from American Community Survey (ACS) form S2504, which gathers information on physical housing characteristics of occupied housing.

In 2019 10% of Michigan's population heated their homes with electricity, making Michigan households the 48th most likely to be heating with electricity.

In 2019 76% of Michigan's population heated their homes with natural gas, making Michigan households the 3rd most likely to be heating with natural gas.

In 2019 13% of Michigan's population heated their homes with other heating fuels, making Michigan households the 22nd most likely to be heating with other heating fuels.

Figure 30: Number of Households Heating by Fuel

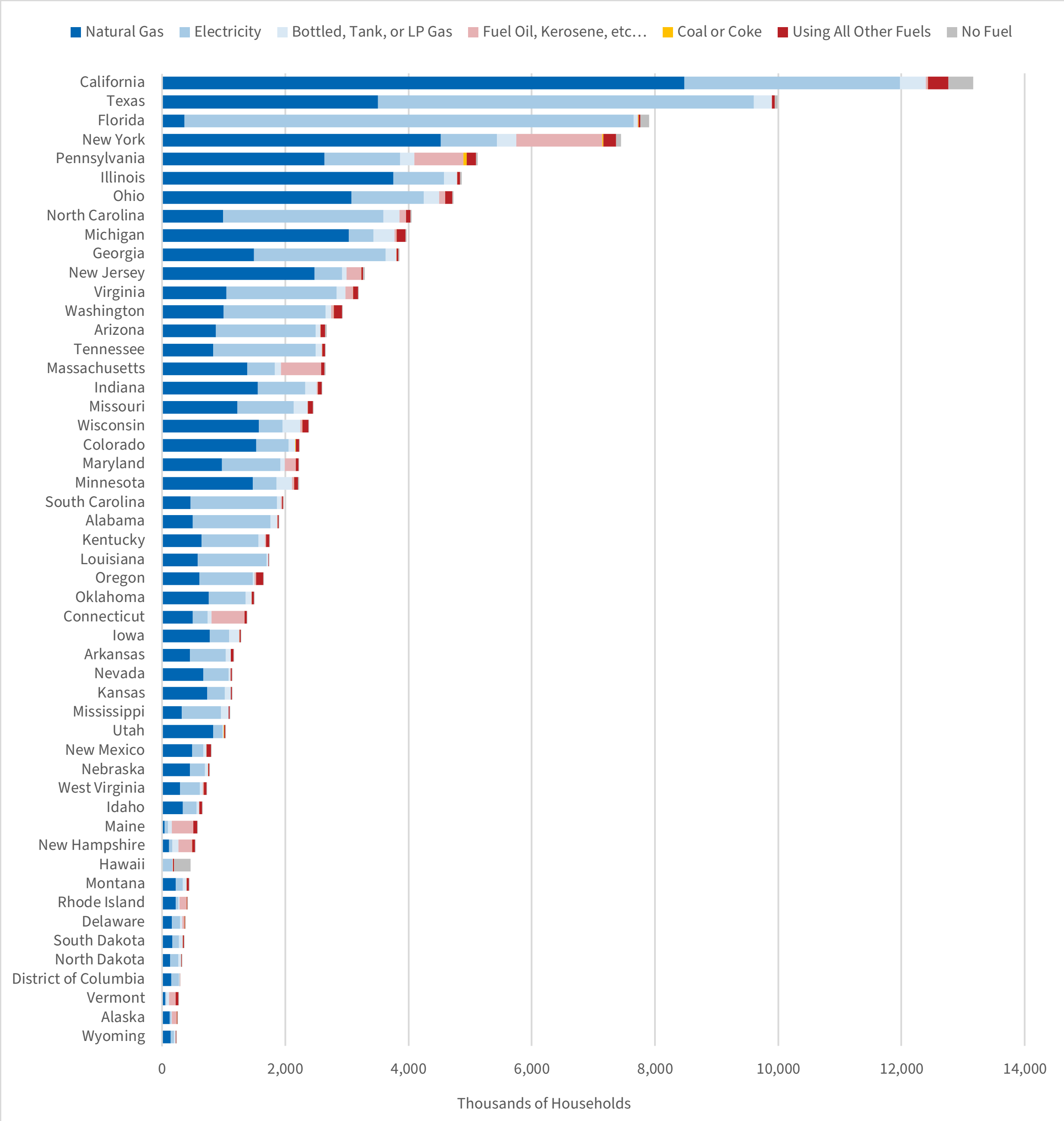


Figure 31: 2019 Percentage of Households Heating by Fuel

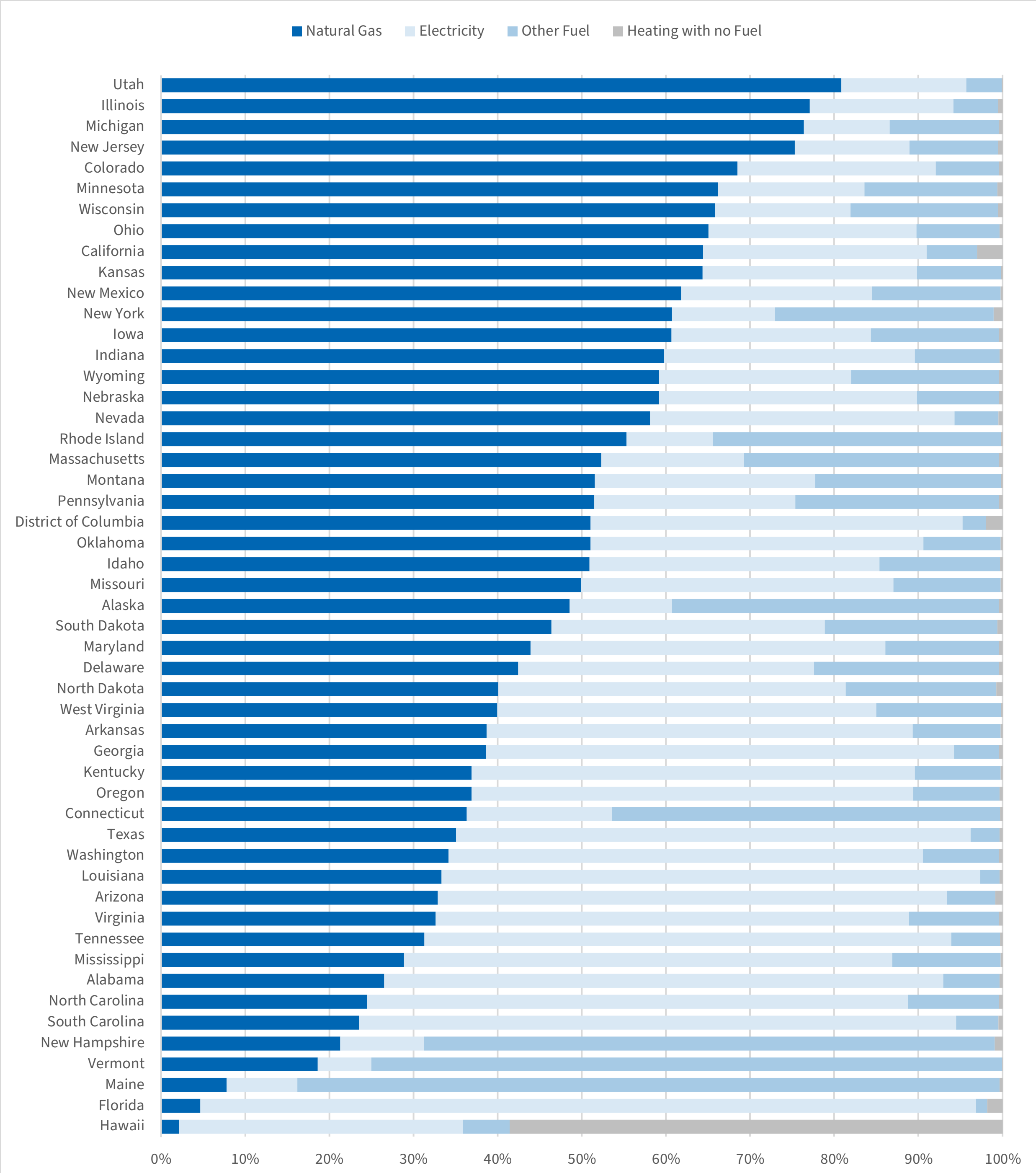


Figure 32: 2019 Percentage of Households Heating with Electricity

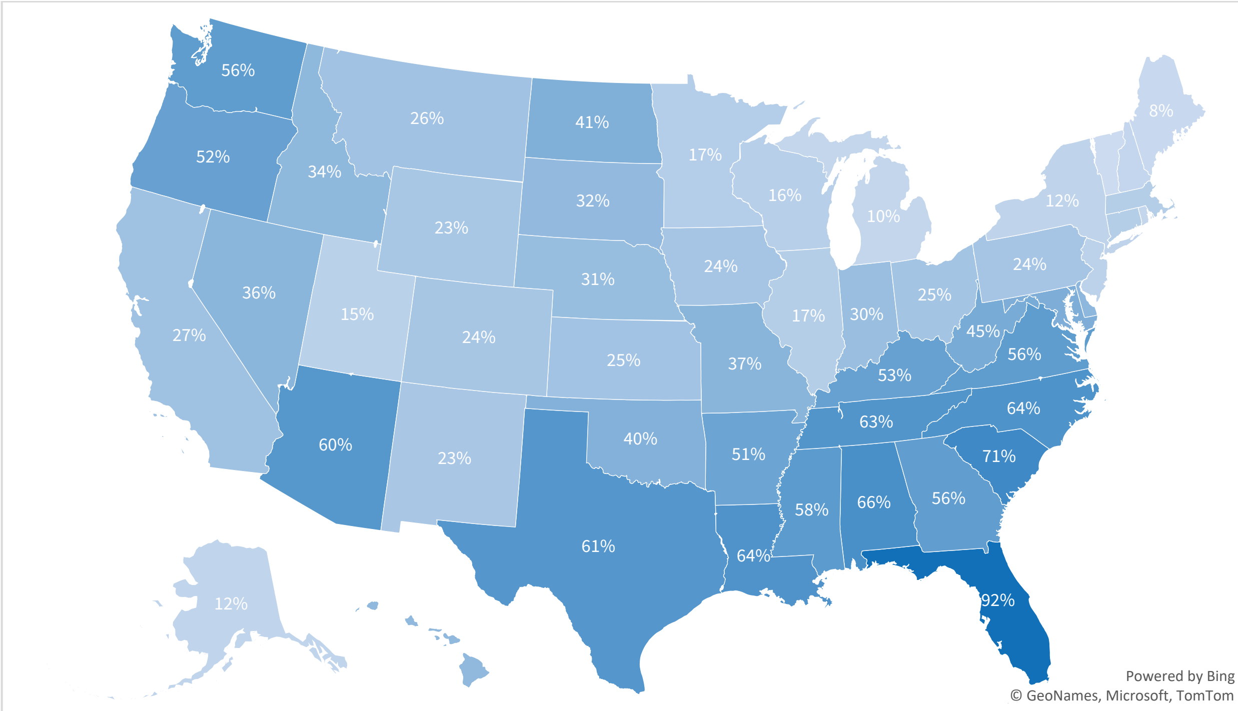


Figure 33: 2019 Percentage of Households Heating with Natural Gas

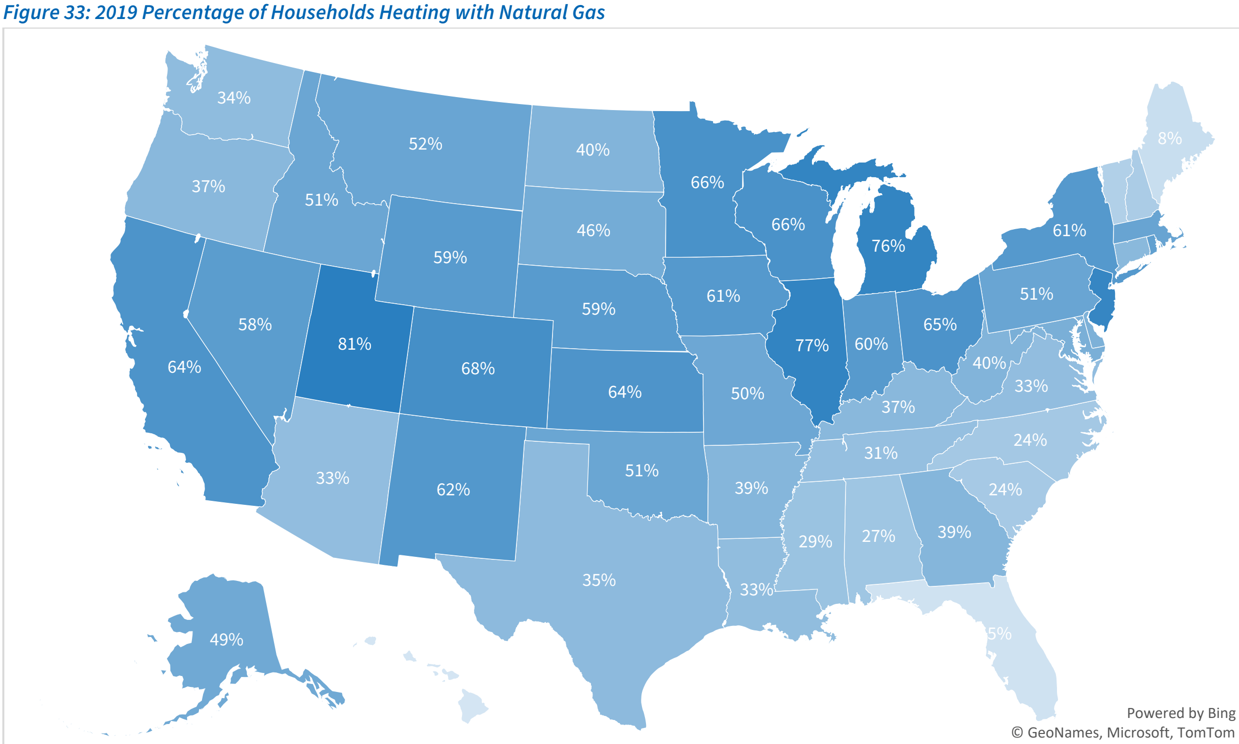
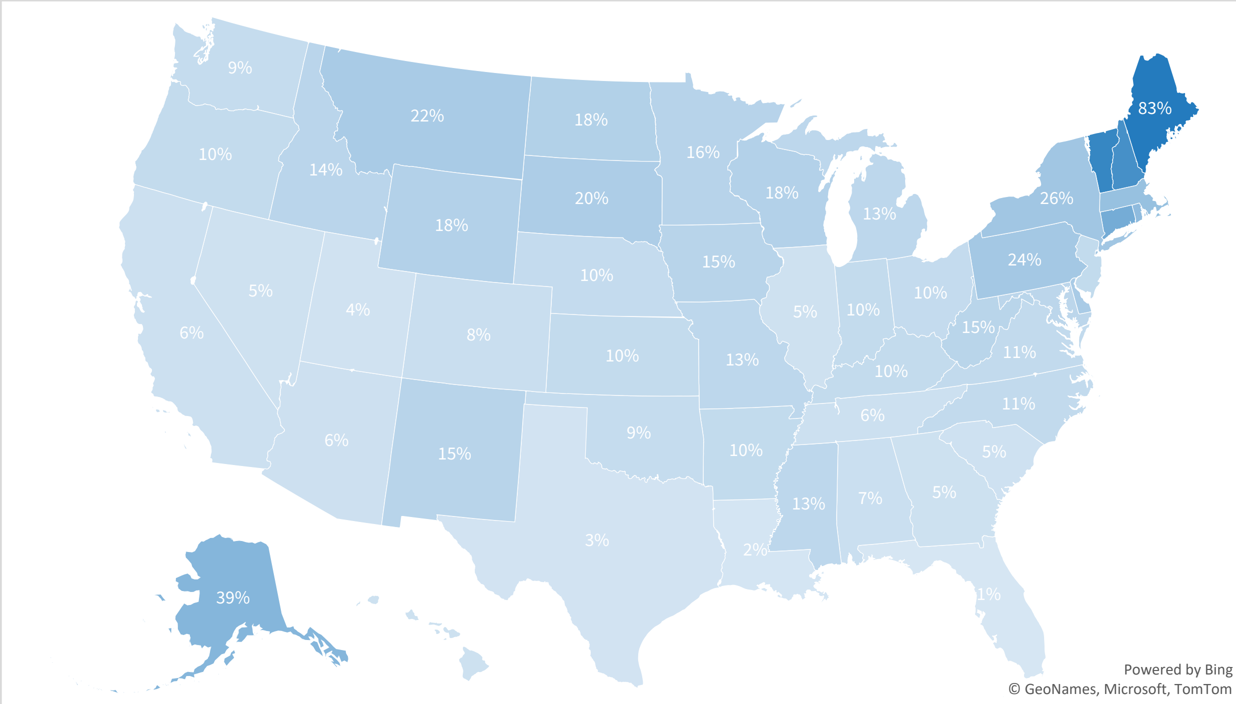


Figure 34: 2019 Percentage of Households Heating with Other Heating Fuels



Household Energy Use

This subsection shows the average residential household use of energy sources. Customers who do not use a particular source do not count toward that source's average use—if a residential property lacks a natural gas hookup, for example, that property does not affect the average natural gas use by customers in that state.

Figures for natural gas and other heating fuels are shown in both their native energy units—therms for natural gas, and MMBTU for other heating fuels—as well as in kWh. This conversion of energy units to a common unit allows for comparison of use between energy types.

The clearest trend in electricity use is that warmer southern states use more electricity than northern states (Figure 36). This use is mostly driven by air conditioning but may also be affected by using electricity as a sole energy source for cooking and home heating. A less intuitive trend is that high use is observed in the Dakotas. This observation tracks with the figures discussed in *Fuel Sources* above, which show that a high percentage of homes are heated with electricity in these relatively cold states (Figure 32). However, the degree of electricity necessary to heat individual homes in the Dakotas may not be reflected in the values shown, as nearly every home in the Dakotas has an electricity hookup, but only 41% heat with electricity, meaning that the trend of high electricity use in these states is being driven by less than half of the states' populations.

Unlike electricity, with its diverse uses, homes with natural gas or other heating fuel hook-ups are likely to be using those fuels, at least in colder states, primarily for household heat, with the use of these fuels for cooking and hot water heating being relatively small compared to home heating.

For electricity and natural gas, the EIA gathers data on both aggregate sales to the residential sector and number of utility customers as counted by the number of meters with active hookups. Thus, household-use metrics are calculated as *residential sales/residential consumers*. Because consumers are counted by number of meters, our denominator may include second homes as well as multiple families behind one meter. Unfortunately, we currently have no way of determining the effects these potential disparities have on our calculations.

Household other heating fuels is calculated differently. The other heating fuels category combines a variety of fuel types and data sources. Residential sector use of other heating fuels is calculated by totaling residential sector uses of coal, distillate fuel oil, kerosene, propane, and wood, which are reported in the EIA's State Energy Data System (SEDS) data sets. This total is then divided by the number of occupied housing units using other heating fuels as calculated by summing Census data (described in *Fuel Sources* above) for occupied housing units using "bottled tank of LP gas," "fuel oil, kerosene, etc…," "coal or coke," and "all other fuels." Because "occupied housing units" is calculated by the Census Bureau in a way that may not correlate to "residential consumers" as reported to the EIA, the way we have calculated household use for other heating fuels does not allow for precise apples-to-apples comparisons with the use of electricity and natural gas.

Table 3: 2019 Michigan Household Energy Use Metrics

Metric	2019 Value	2019 Rank
Electricity Use per Household (Kilowatt Hours)	7,640	42
Natural Gas Use per Household (Therms)	993	3
Other Heating Fuel Use per Household (MMBTU)	162	10

The table above shows Michigan households using the 3rd most natural gas out of the 50 states and DC, but the 42nd most electricity and the 10th most other heating fuels. These trends follow from Michigan's geography as a northern state that uses a lot of heating fuels in the winter, but less electricity in the summer for cooling. Over the next decades, as more Michigan homes begin to heat with efficient heat pumps these use numbers may change to reflect high electricity demands during the winter.

Figure 35: 2019 Electricity Use per Residential Customer in Kilowatt Hours

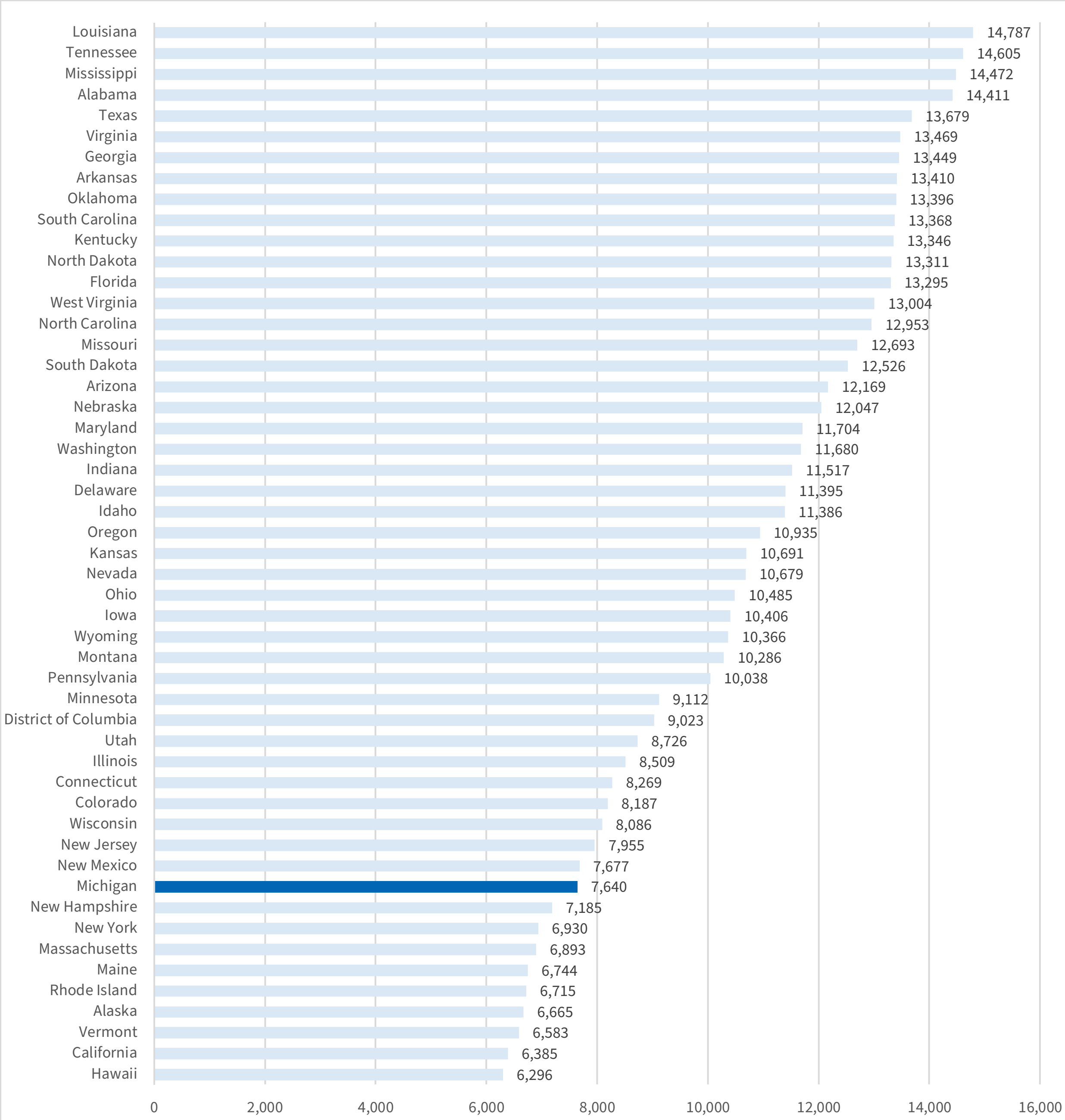


Figure 36: 2019 Electricity Use per Residential Customer in Kilowatt Hours

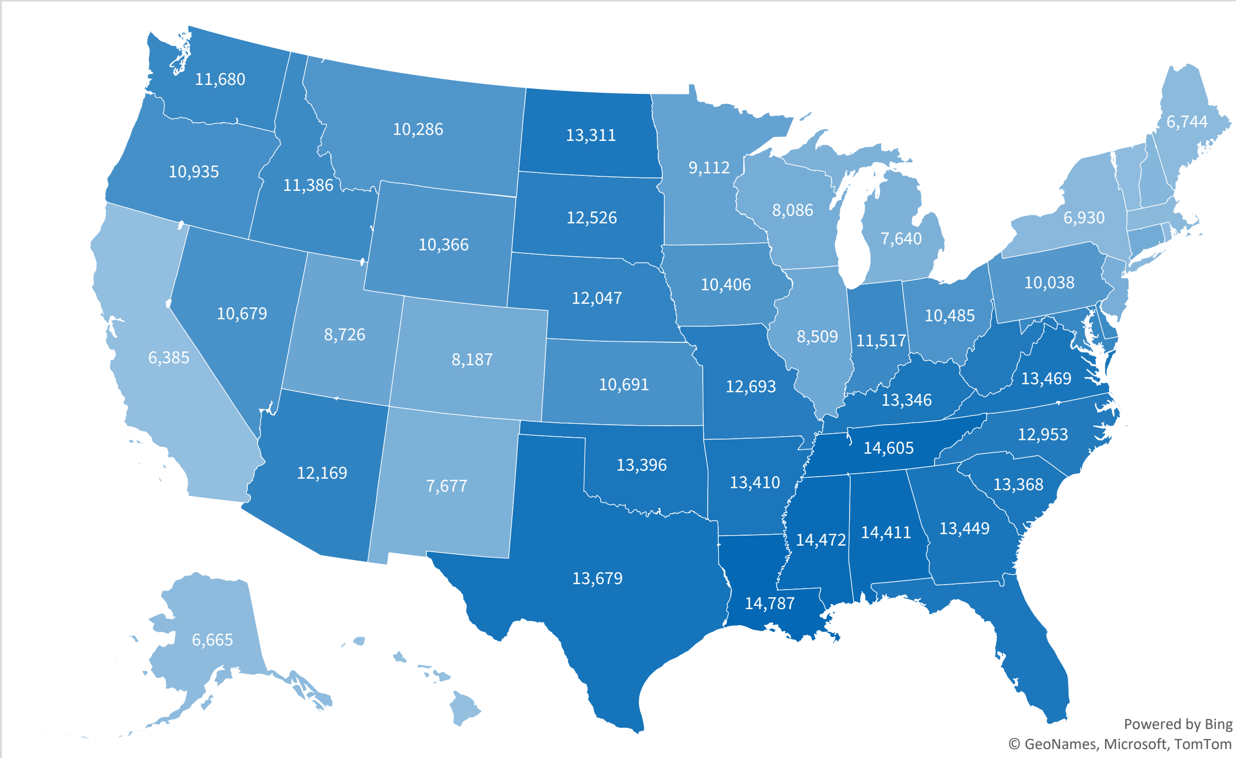


Figure 37: 2019 Natural Gas Use per Residential Customer

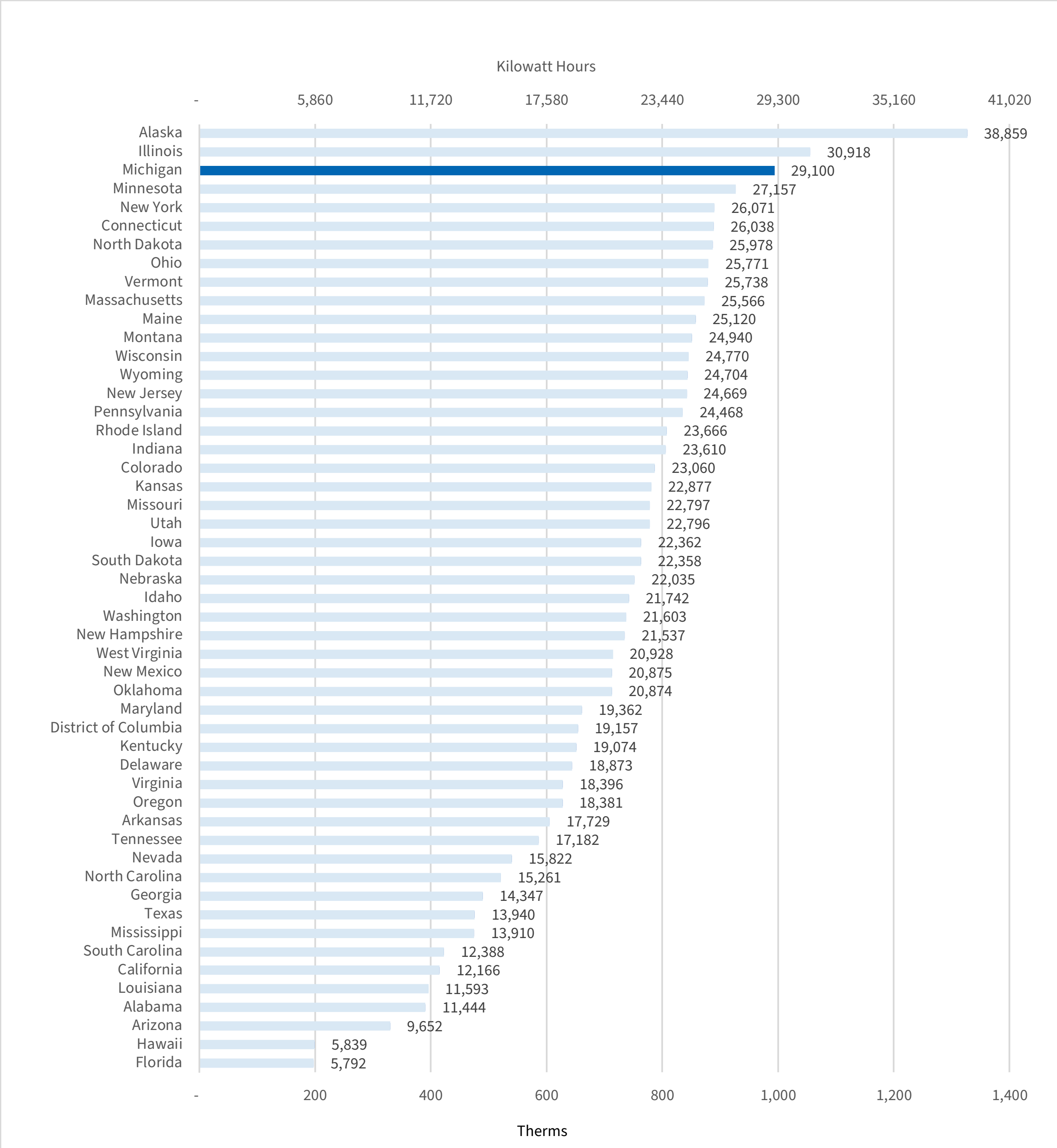


Figure 38: 2019 Natural Gas Use per Residential Customer in Therms

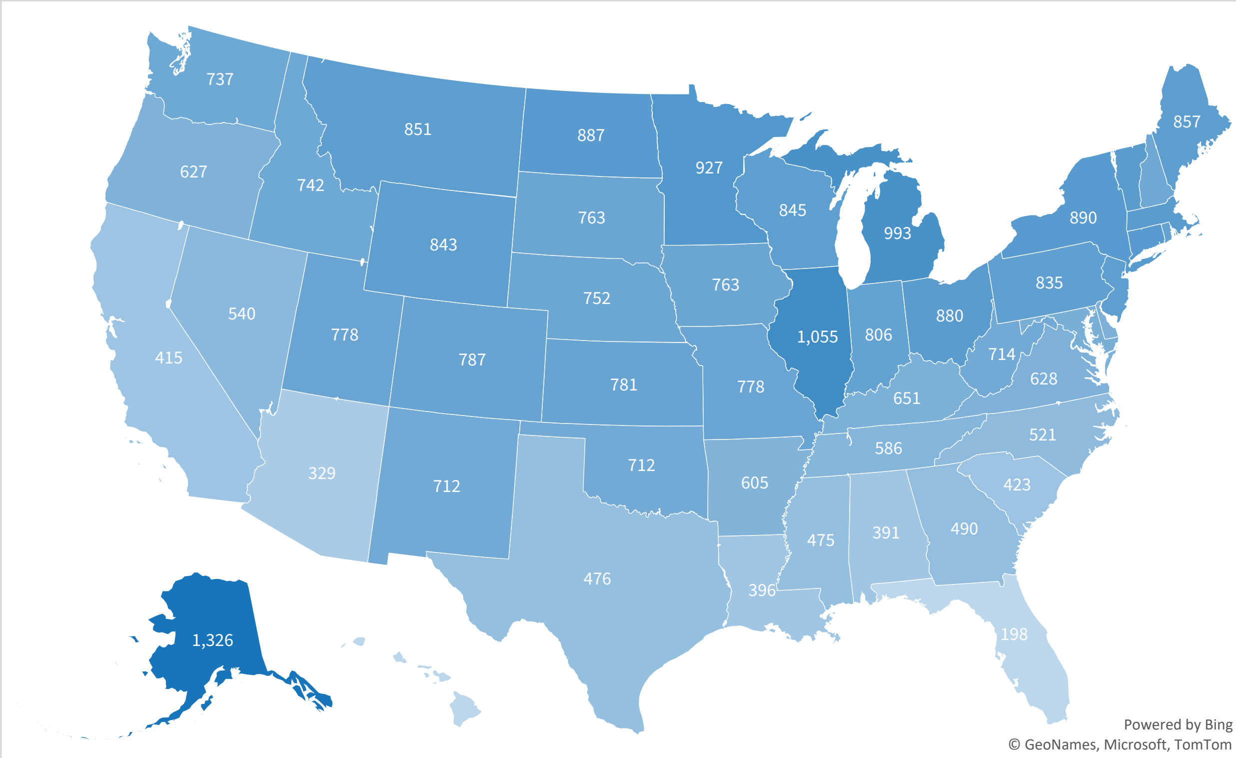


Figure 39: 2019 Natural Gas Use per Residential Customer in Kilowatt Hours

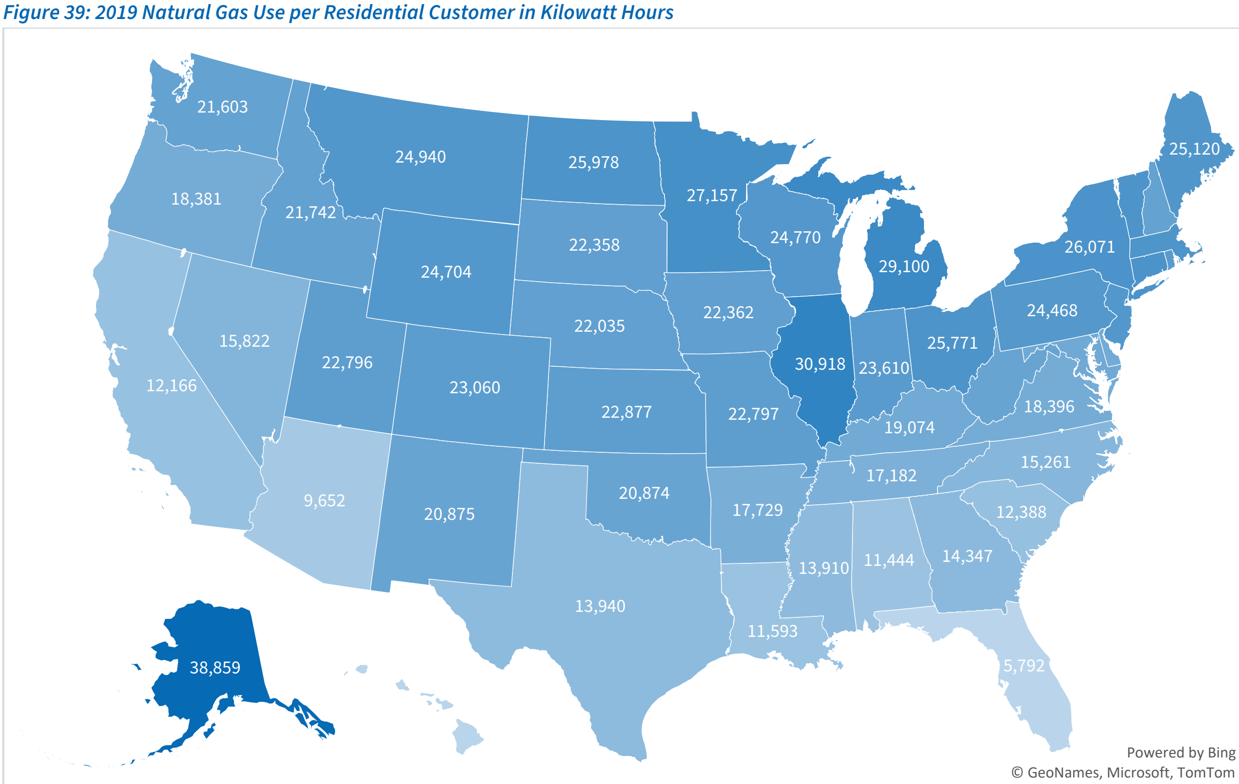


Figure 40: 2019 Other Heating Fuel Use per Occupied Housing Unit Heating with Other Heating Fuels

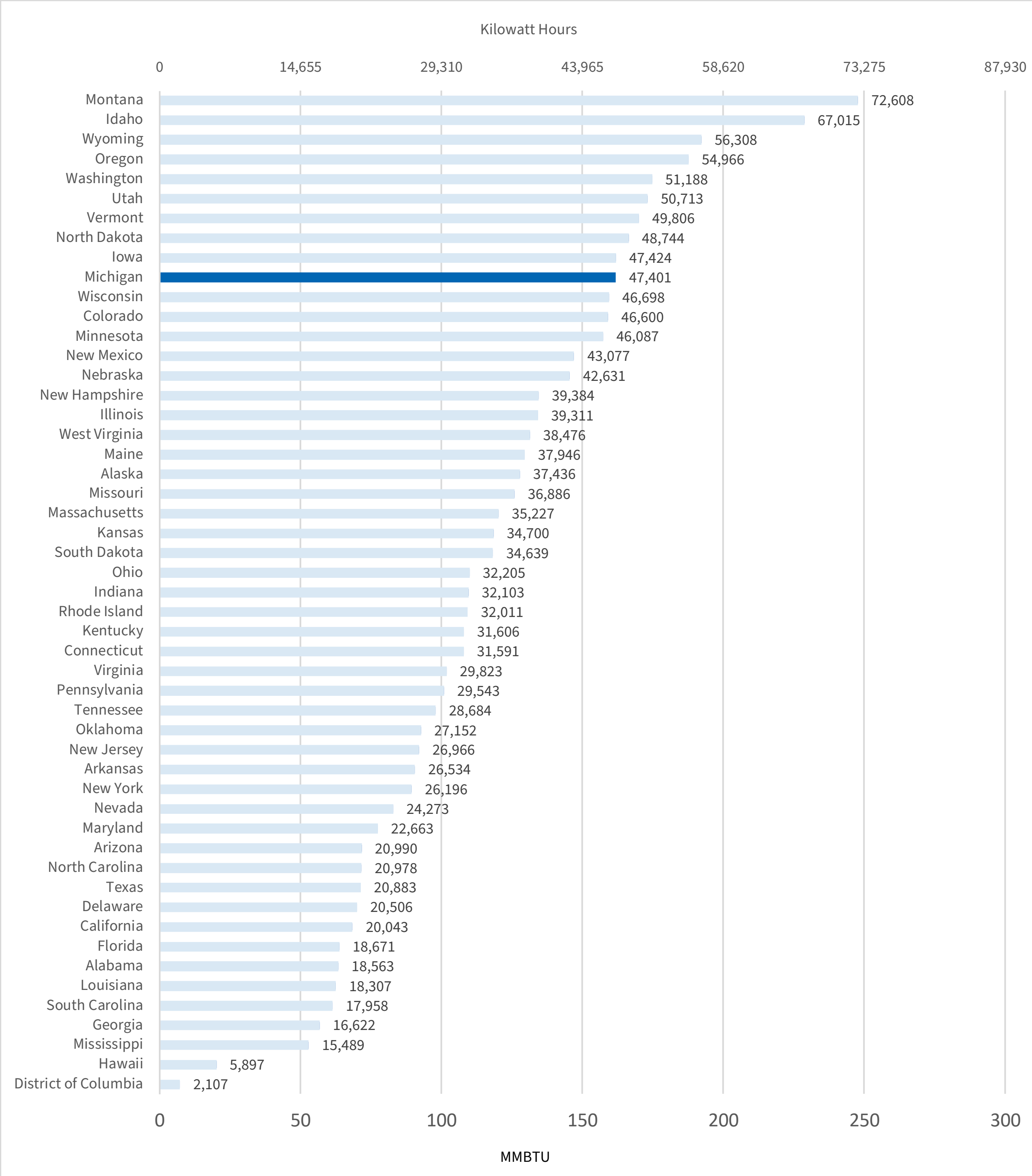


Figure 41: 2019 Other Heating Fuel Use per Occupied Housing Unit Heating with Other Heating Fuels in MMBTU

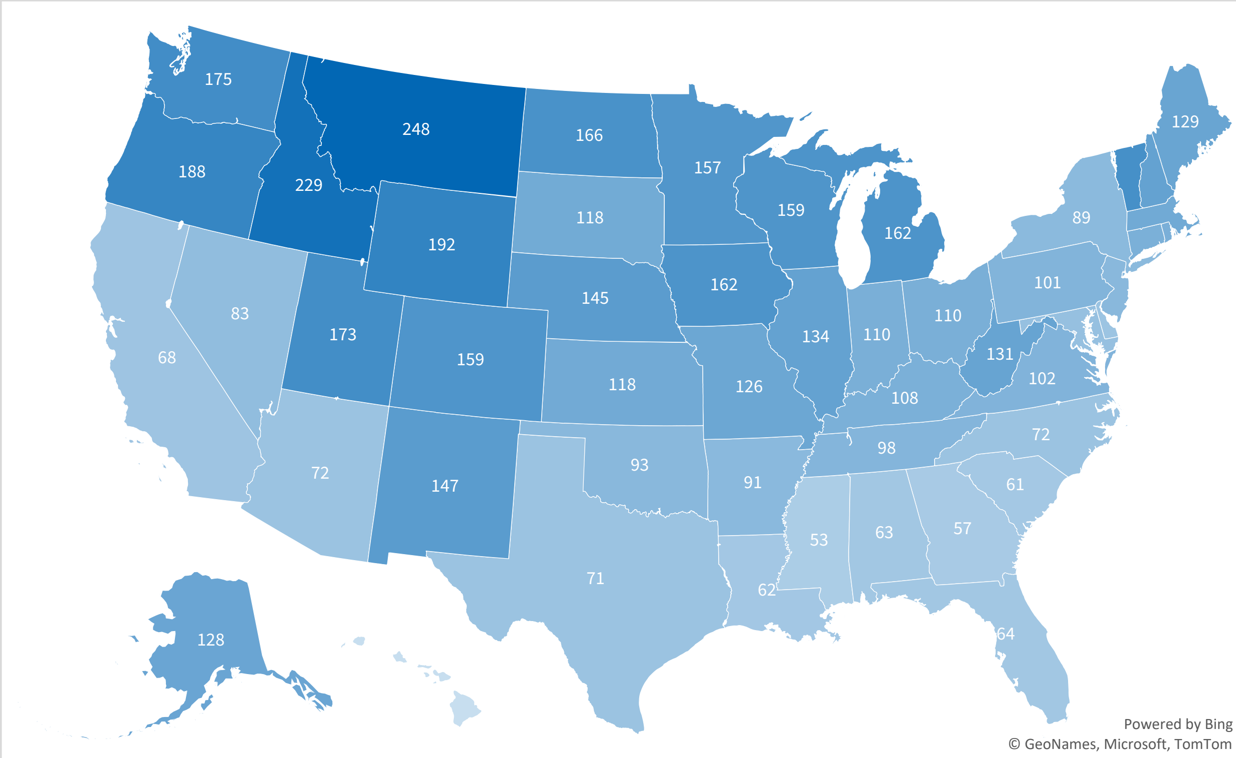
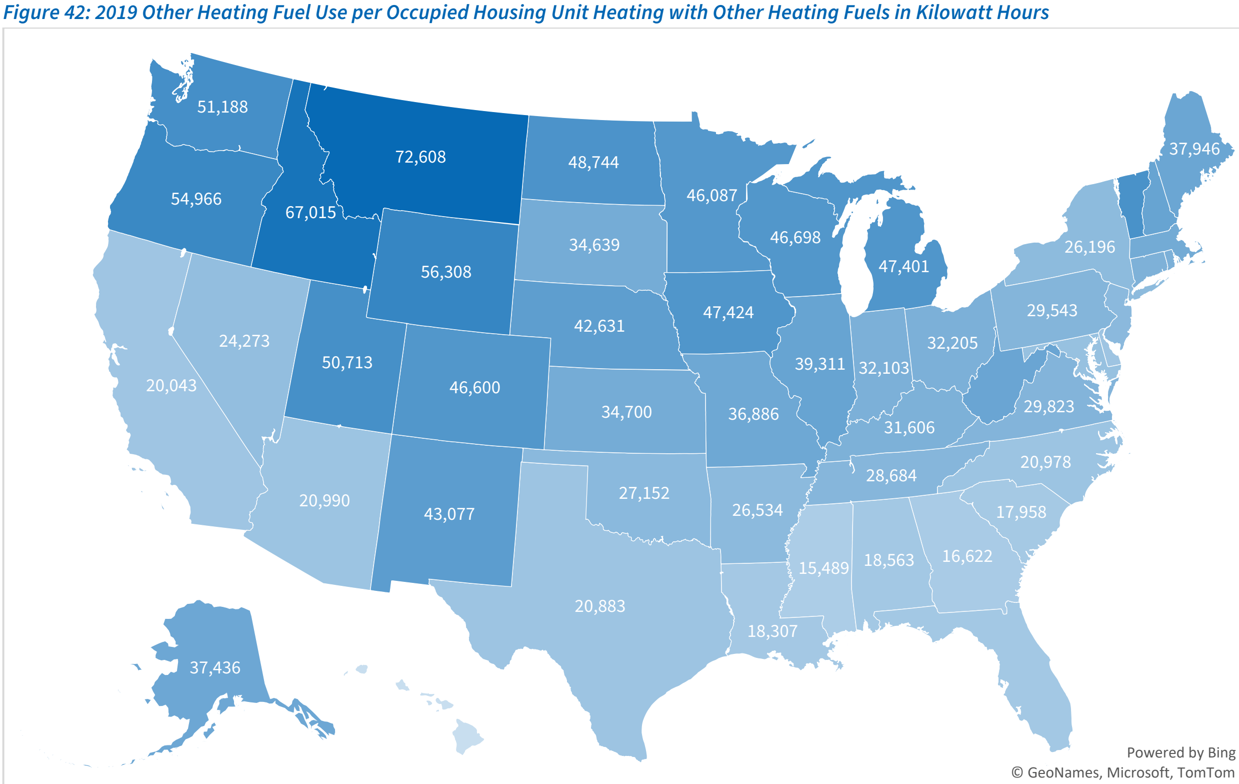


Figure 42: 2019 Other Heating Fuel Use per Occupied Housing Unit Heating with Other Heating Fuels in Kilowatt Hours



Household Electricity Costs and Expenditures

Electricity bills often have many components: fixed monthly charges, charges based on the customer's peak rate of power usage in the billing month or previous year, a charge per kWh of electricity and others. The way utilities assign costs to these components of the bill varies across states and between utilities and classes of customers. Because, for customer purposes, each kWh is identical, dividing the total bill by the kWh used is generally the best way to compare utility costs.

The EIA collects monthly data from each utility in each state on the amount of electricity sold and the revenue from electricity by customer class. Customer classes include residential, commercial, industrial, transportation, and "other," with almost all electricity delivered in most states going to the first three classes. The EIA makes these data available through its Electric Data Browser.

Table 4: 2019 Michigan Household Electricity Costs and Expenditures

Metric	2019 Value	2019 Rank
Residential Electricity Cost (Dollars per Kilowatt Hour)	$0.16	11
Average Yearly Household Electricity Expenditures	$1,203	39

The figures in this section, as summarized in the chart above show that Michigan has the 11th highest electricity cost in the country, higher than any of its peers in the Midwest, as is easily visible in Figure 44. Despite these high electricity costs, Michiganders' yearly electricity expenditures are only the 39th highest in the country. This is due to relatively low electricity use statistics in Michigan, described above in *Household Energy Use*.

Figure 47 shows that that per kWh residential electricity costs vary from about nine cents per kWh in the City of Zeeland municipal utility to thirty-one cents per kWh from the Bayfield Electric Cooperative, Inc. The most obvious trend in Michigan's residential electricity costs is that the highest cost utilities are in the Upper Peninsula. The Upper Peninsula's high electricity costs result from the high expense of distribution infrastructure in rural areas plus the relatively low amount of local generation resources.

Figure 43: 2019 Electricity Expenditures per Residential Customer

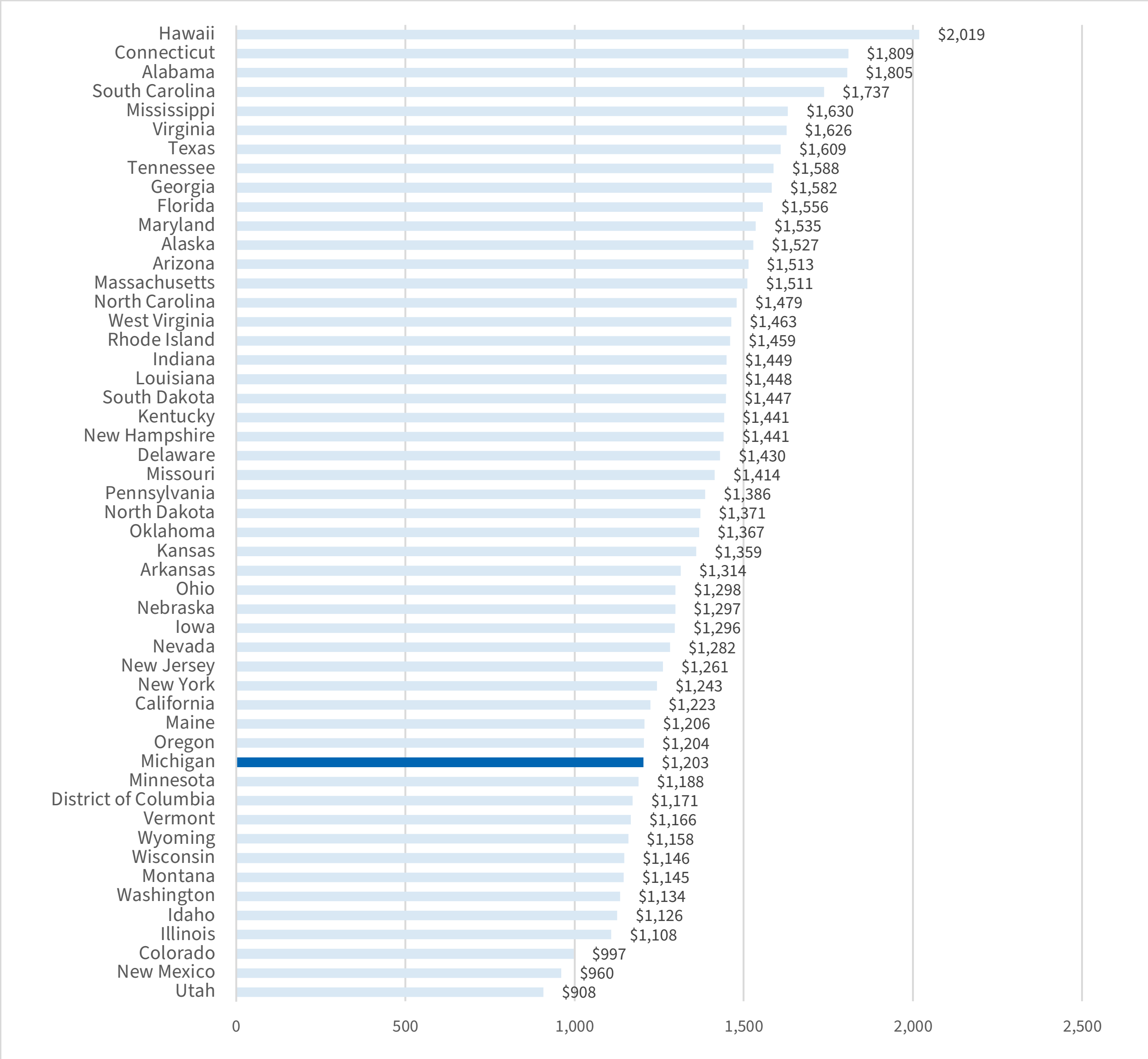


Figure 44: 2019 Electricity Expenditures per Residential Customer in Dollars

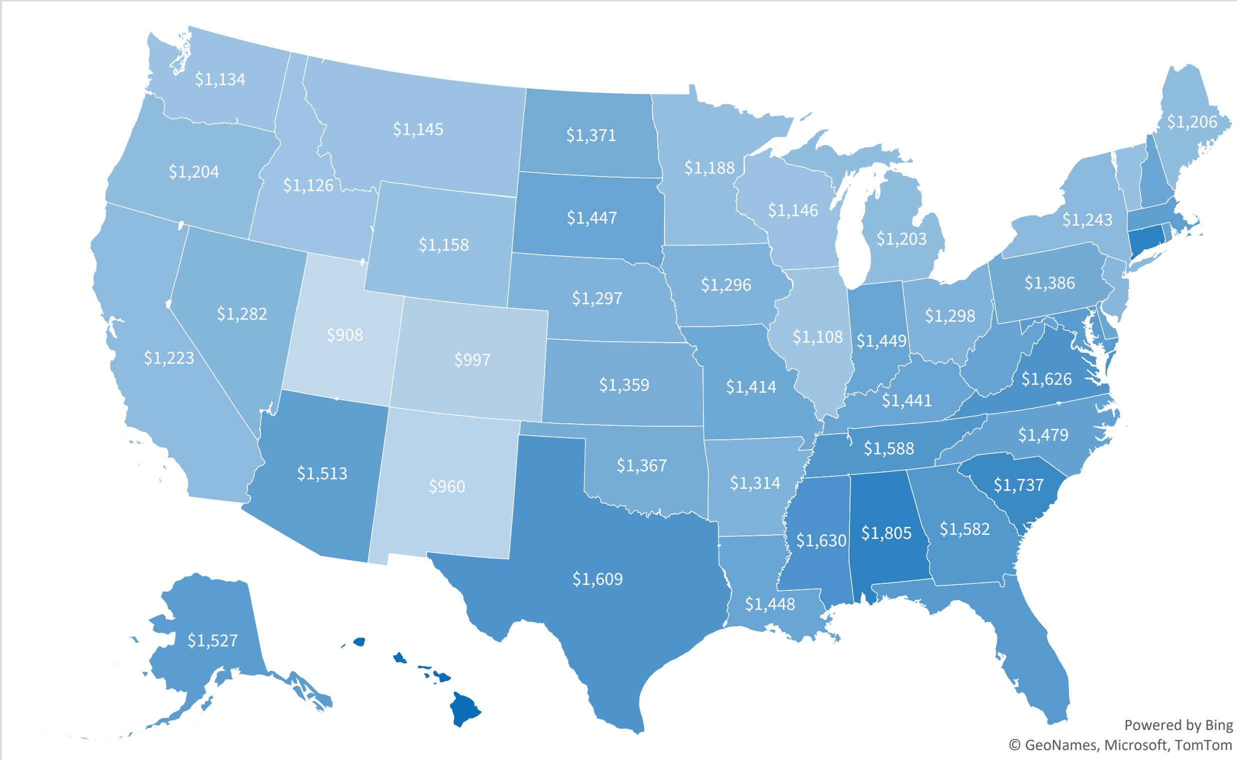


Figure 45: 2020 Cost per Kilowatt Hour of Electricity in the Residential Sector

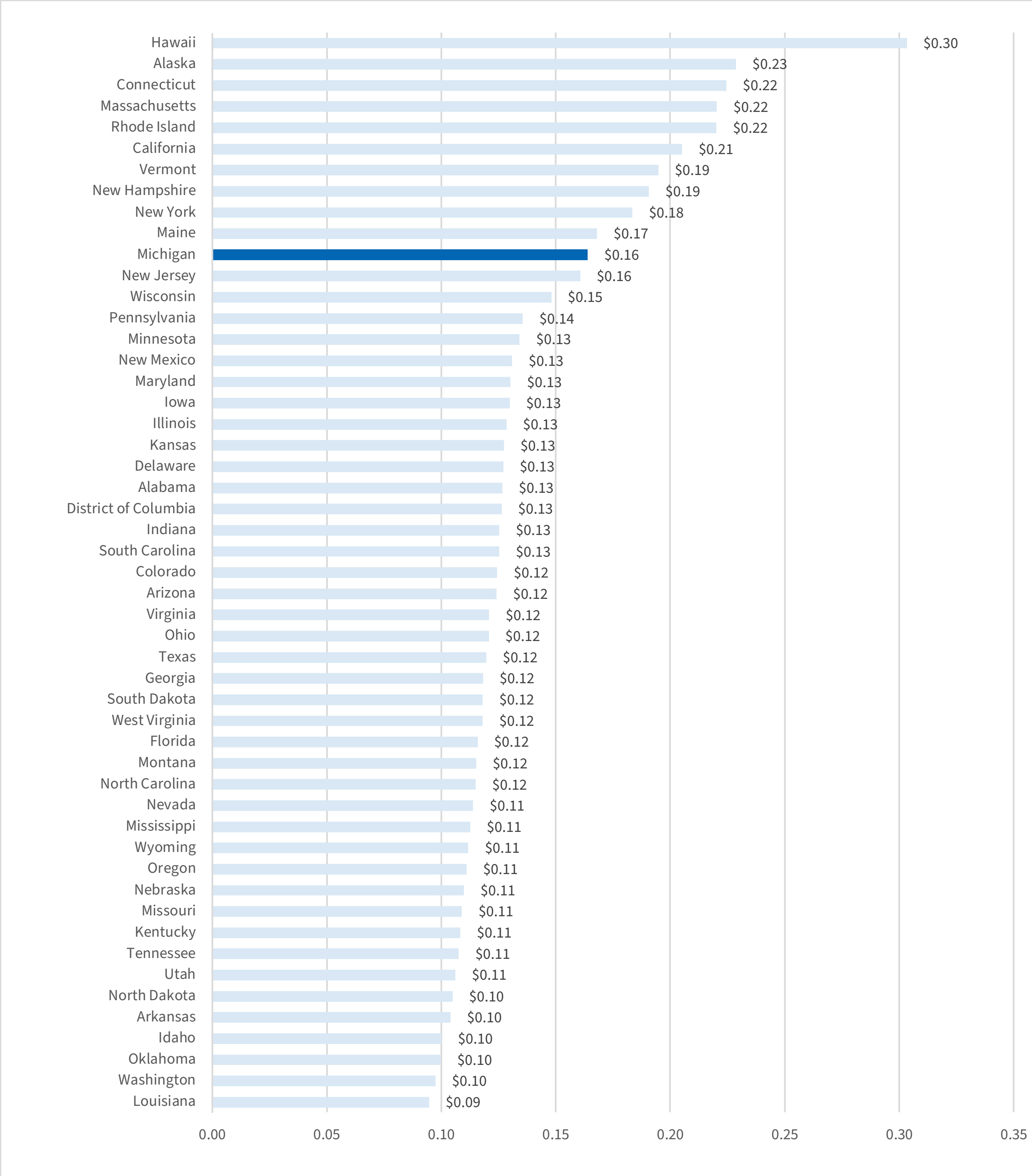


Figure 46: 2020 Cost per Kilowatt Hour of Electricity in the Residential Sector in Dollars

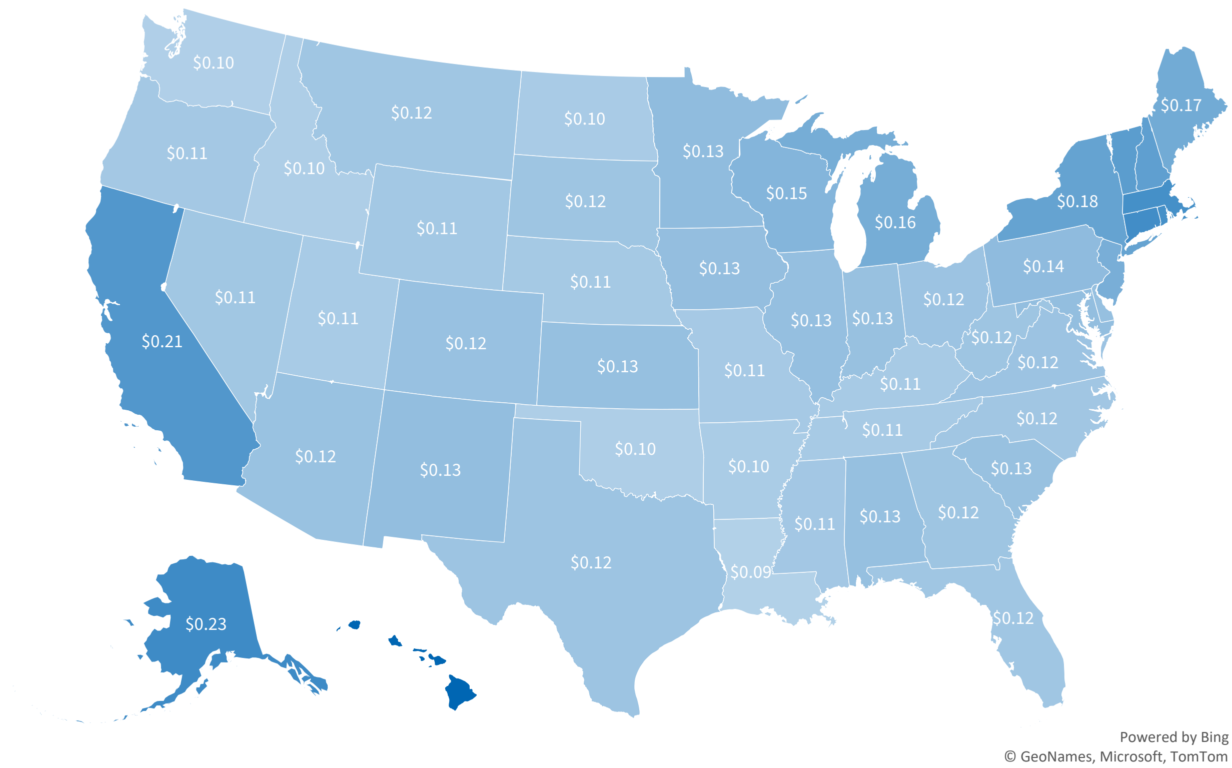
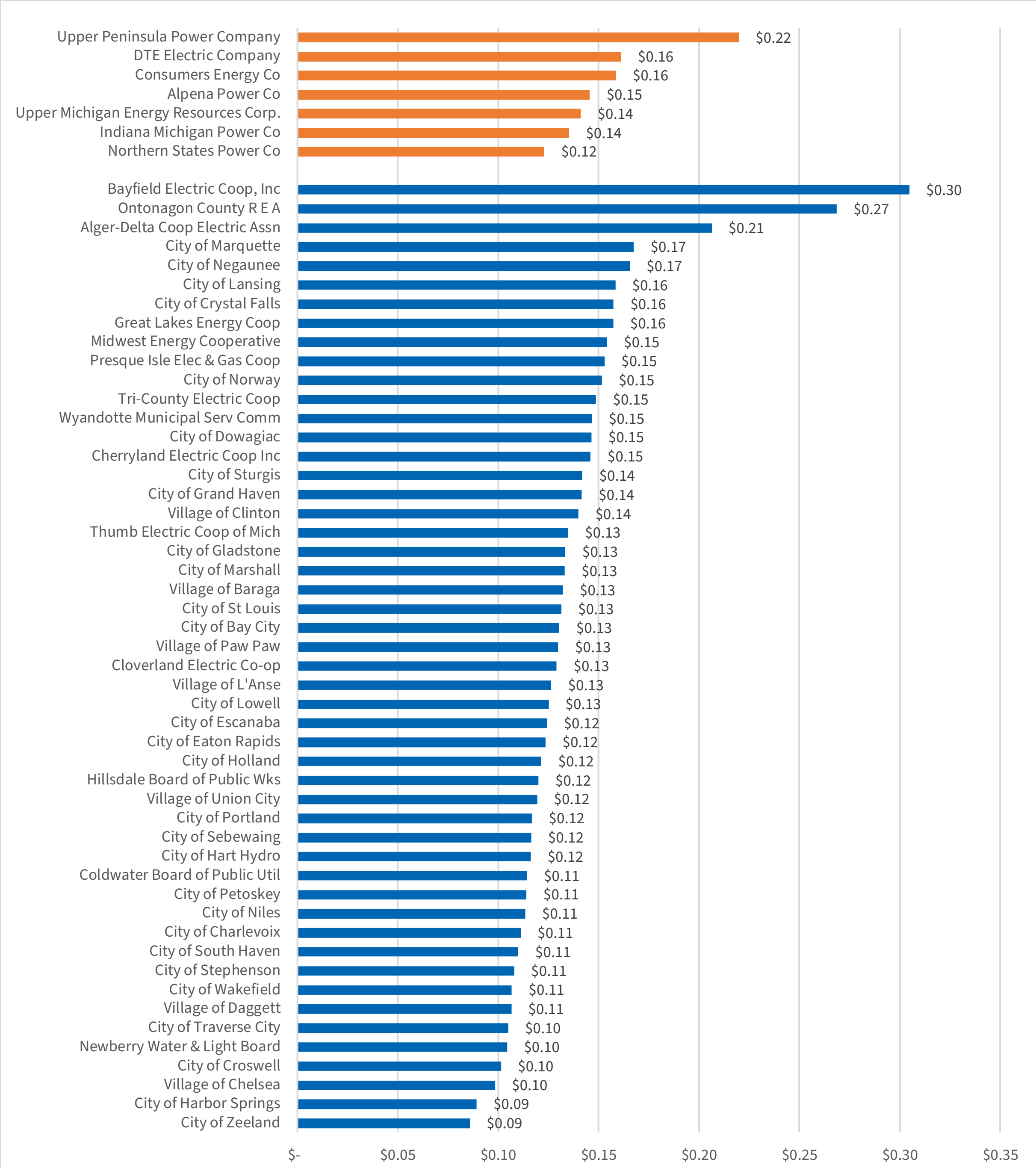


Figure 47: Cost per Kilowatt Hour of Electricity in the Residential Sector for Michigan Utilities



Household Natural Gas Costs and Expenditures

Although responsible for significant greenhouse gas emissions and other pollutants, natural gas remains an affordable and accessible fuel for water and space heating in cold climates. However, consumers are not insulated from price spikes or distribution disruptions, especially during harsh winters.

Residential consumers purchase natural gas in units called therms, which are equivalent to 100 cubic feet of natural gas. To facilitate energy cost comparisons with electricity, this section contains figures that show both therms, the unit customers see on their gas bill, and kWh, a unit generally used to measure electricity. The conversion factor from therms to kWh is 29.3 kWh to 1 therm. This allows readers to compare the absolute energy costs of these disparate energy forms. Comparing natural gas and electricity costs shows that natural gas is usually a cheaper form of energy than electricity, which helps explain why it is a more common heating fuel in climates with high heating requirements.

Although the geographies of high and low costs and expenditures are different for natural gas than for electricity, the trends that relate costs to expenditures and use follow a similar logic to electricity's. There are higher expenditures but lower costs in areas with higher use, such as colder, more northern climates where natural gas is a common heating fuel, as described in *Household Energy Use*.

Table 5: 2019 Michigan Household Natural Gas Costs and Expenditures

Metric	2019 Value	2019 Rank
Residential Natural Gas Cost (Dollars per Therm)	$0.81	39
Average Yearly Household Natural Gas Expenditures	$802	17

Unsurprisingly, given the trends described above, household expenditures on natural gas are relatively high, the 17th highest in the nation, but cost per therm is only the 39th highest in the nation. Figures 49 and 51 show that Michigan's costs and expenditures are about average when compared to its neighboring states, with lower costs and expenditures than both Illinois and Ohio, but higher costs than Wisconsin and higher expenditures than Wisconsin and Indiana.

Figure 48: 2019 Natural Gas Expenditures per Residential Customer

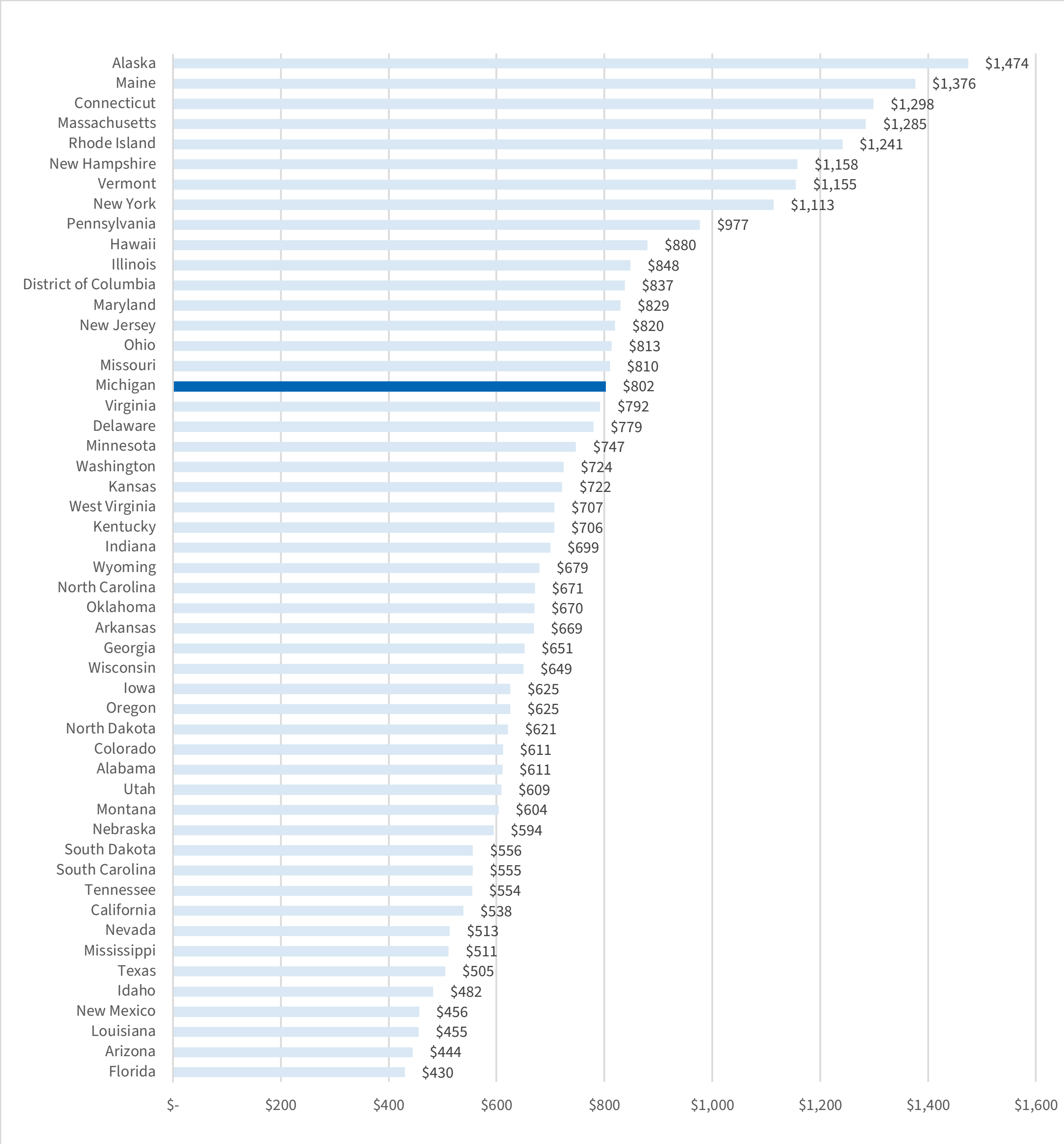


Figure 49: 2019 Natural Gas Expenditures per Residential Customer in Dollars

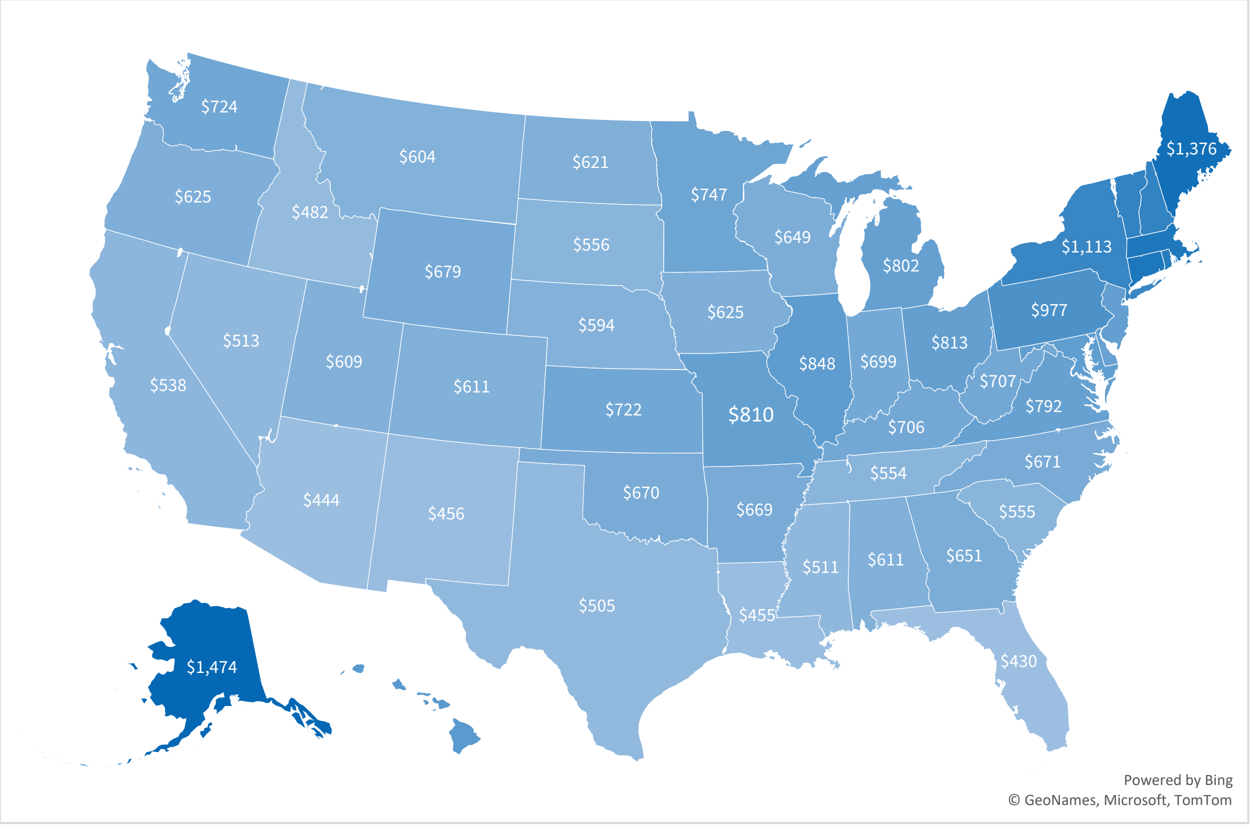


Figure 50: 2019 Cost per Therm and kWh of Natural Gas for Residential Customers

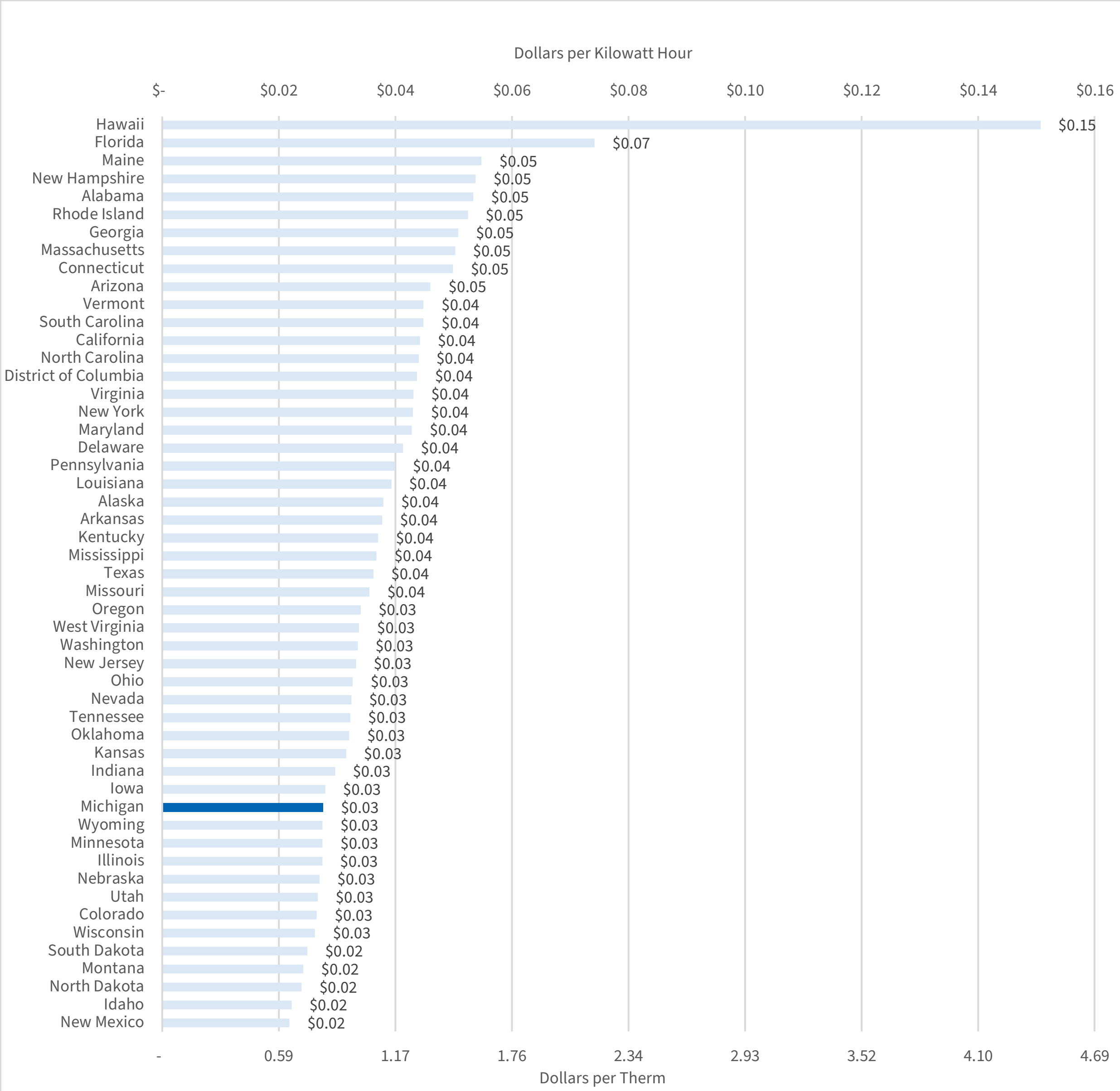


Figure 51: Cost per Therm of Natural Gas for Residential Customers in Dollars

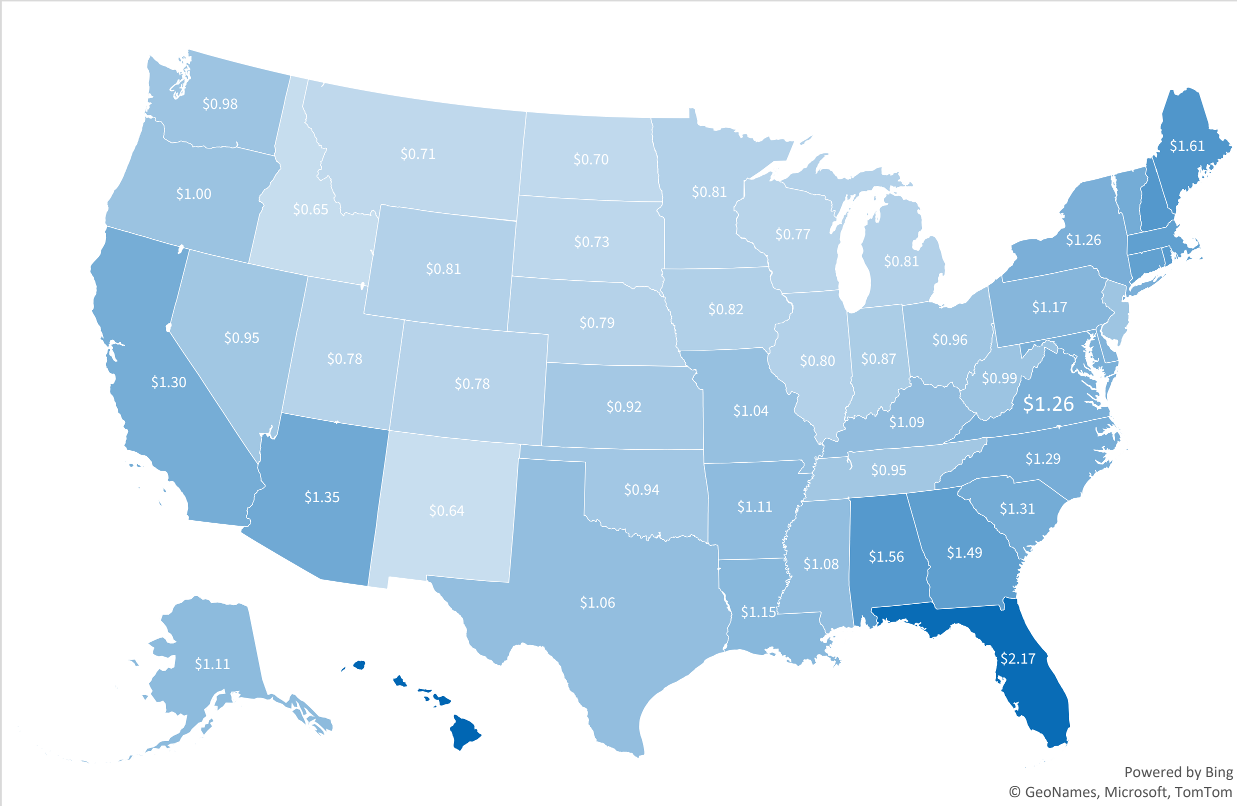


Figure 52: 2019 Cost per Kilowatt Hour of Natural Gas for Residential Customers in Dollars

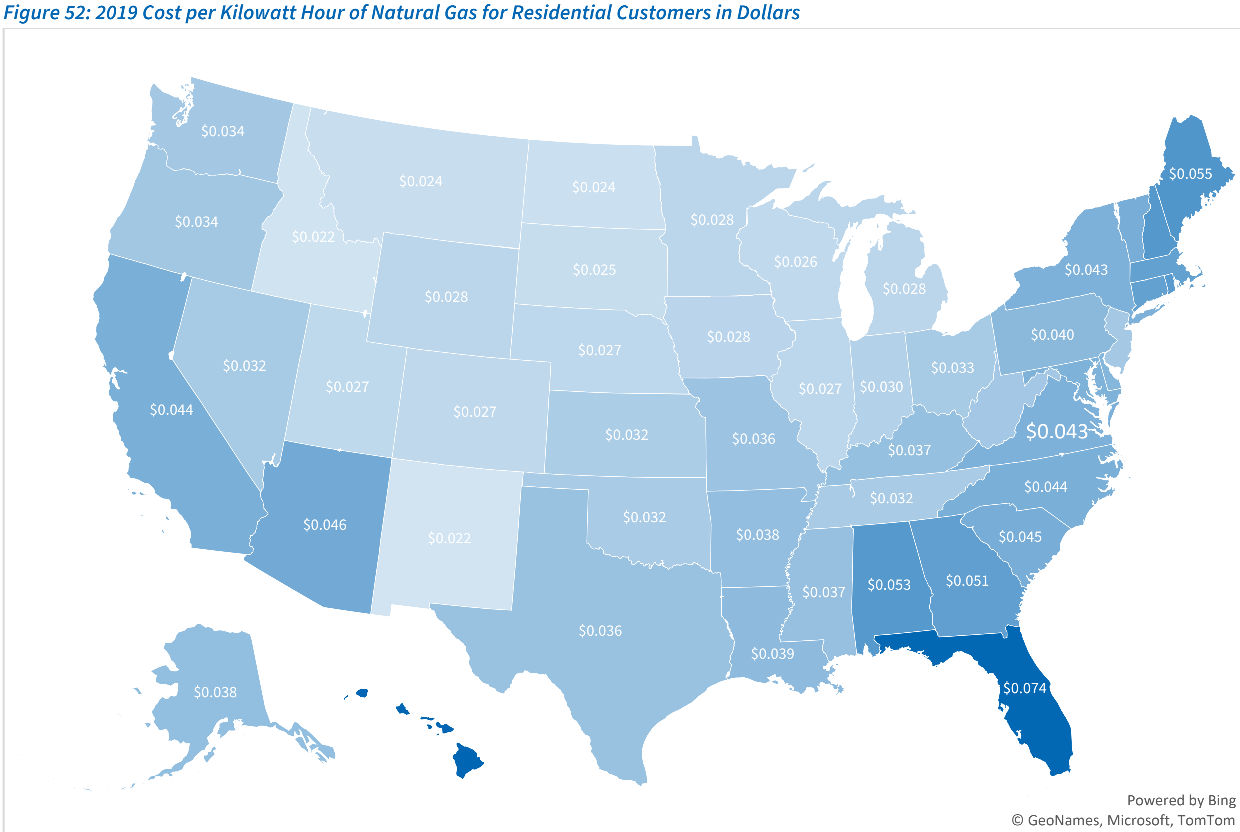


Figure 53: 2019 Natural Gas Price per Therm for Michigan Utilities

Household Other Heating Fuels Costs and Expenditures

As described in *Household Energy Use,* "other heating fuels" references a variety of heating fuels including propane, kerosene, fuel oils, wood, and more. Residential consumers purchase each of these fuels in different forms and units, but when reporting consumption of these fuels, the EIA converts the energy embodied in those materials to a basic unit of energy measurement—MMBTU. To facilitate energy cost comparisons with electricity, this section contains figures that show both MMBTU, the unit the data were reported in, and kWh, a unit generally used to measure electricity. The conversion factor from MMBTU to kWh is 293 kWh to 1 MMBTU.

Table 6: 2019 Michigan Household Other Heating Fuels Costs and Expenditures

Metric	2019 Value	2019 Rank
Household Other Heating Fuel Cost (Dollars per MMBTU)	$11.83	40
Average Yearly Household Other Heating Fuels Expenditures	$1,914	16

The trend in Michigan's other heating fuels costs and expenditures nearly mirror that of natural gas. Michigan ranks 16th for yearly expenditures and 40th for per MMBTU costs. However, compared to adjacent states (Figures 55 and 57), Michigan has the highest expenditures, but lower per MMBTU costs than all adjacent states but Wisconsin.

Figure 54: 2019 Other Heating Fuel Expenditures per Occupied Housing Unit Heating with Other Heating Fuels

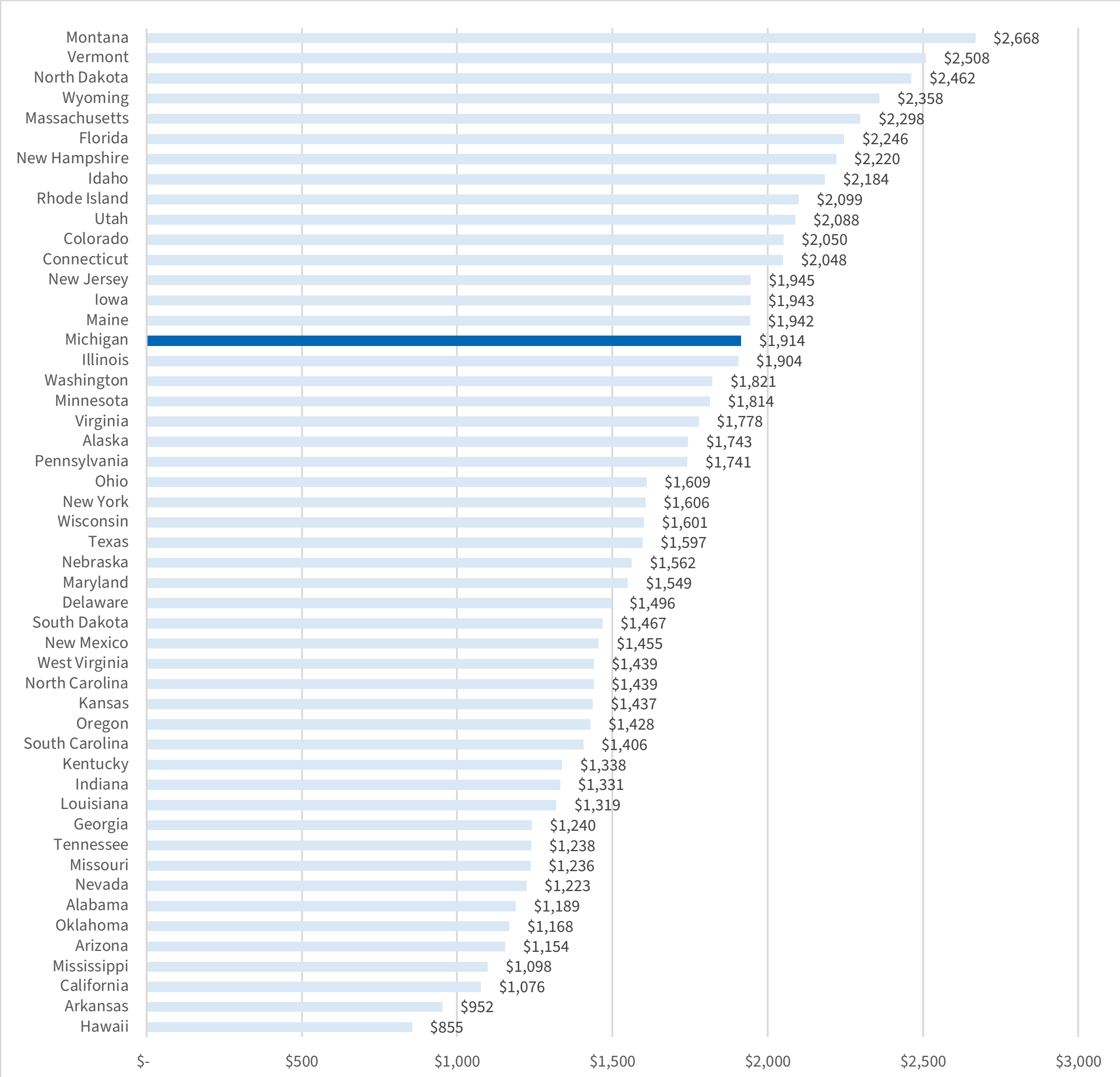


Figure 55: 2019 Other Heating Fuel Expenditures per Occupied Housing Unit Heating with Other Heating Fuels in Dollars

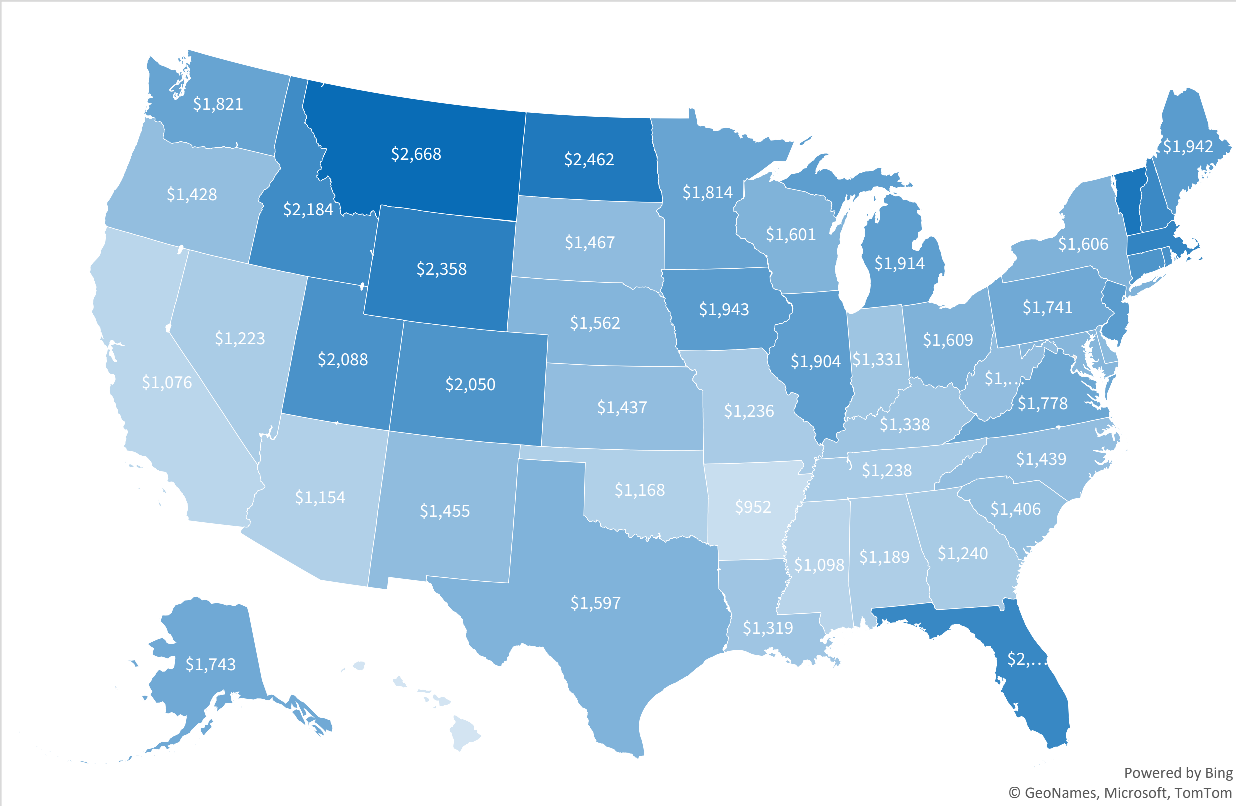


Figure 56: 2019 Other Heating Fuel Cost for Occupied Housing Units Heating with Other Heating Fuels

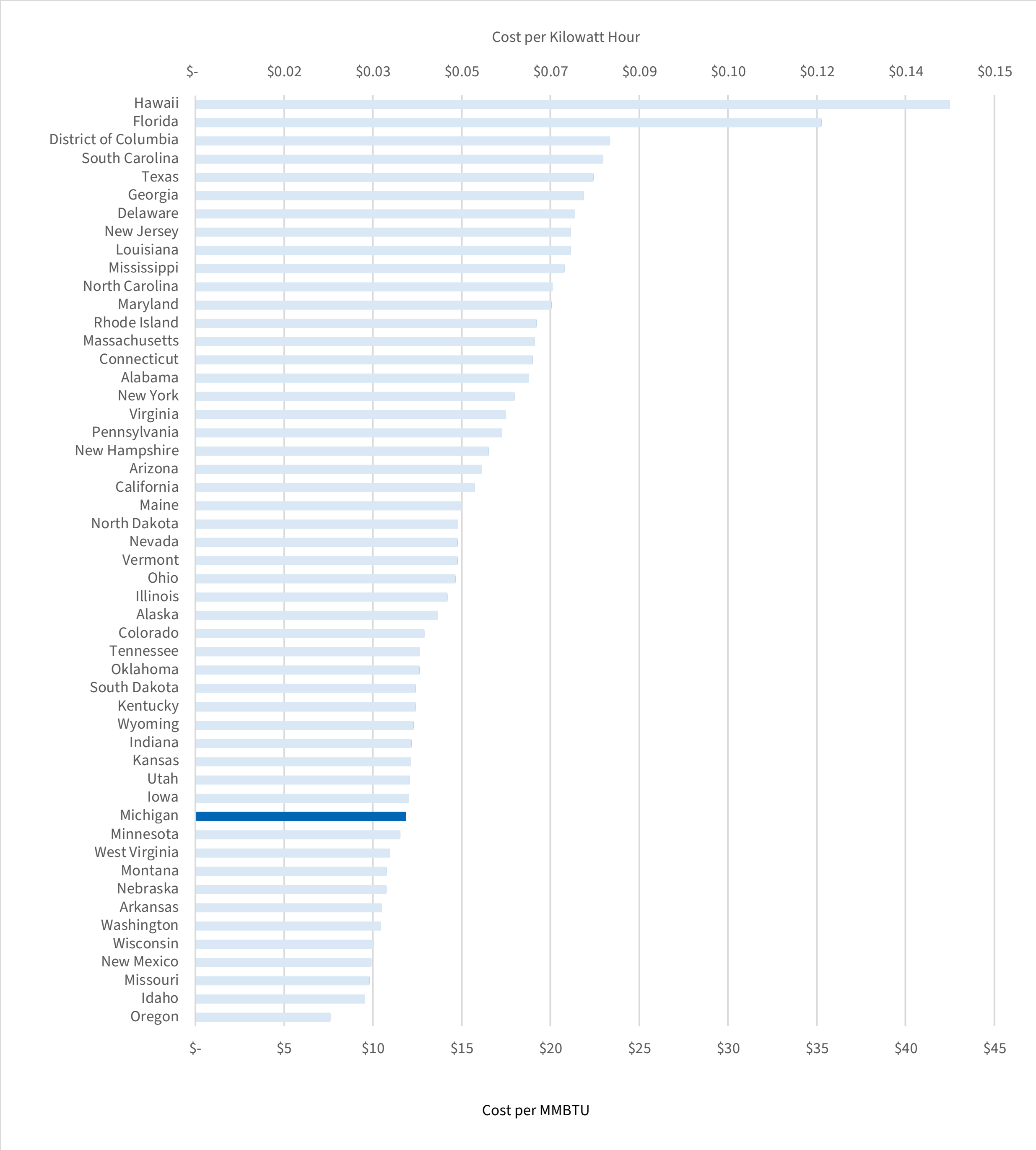


Figure 57: Other Heating Fuel Cost per MMBTU for Occupied Housing Units Heating with Other Heating Fuels in Dollars

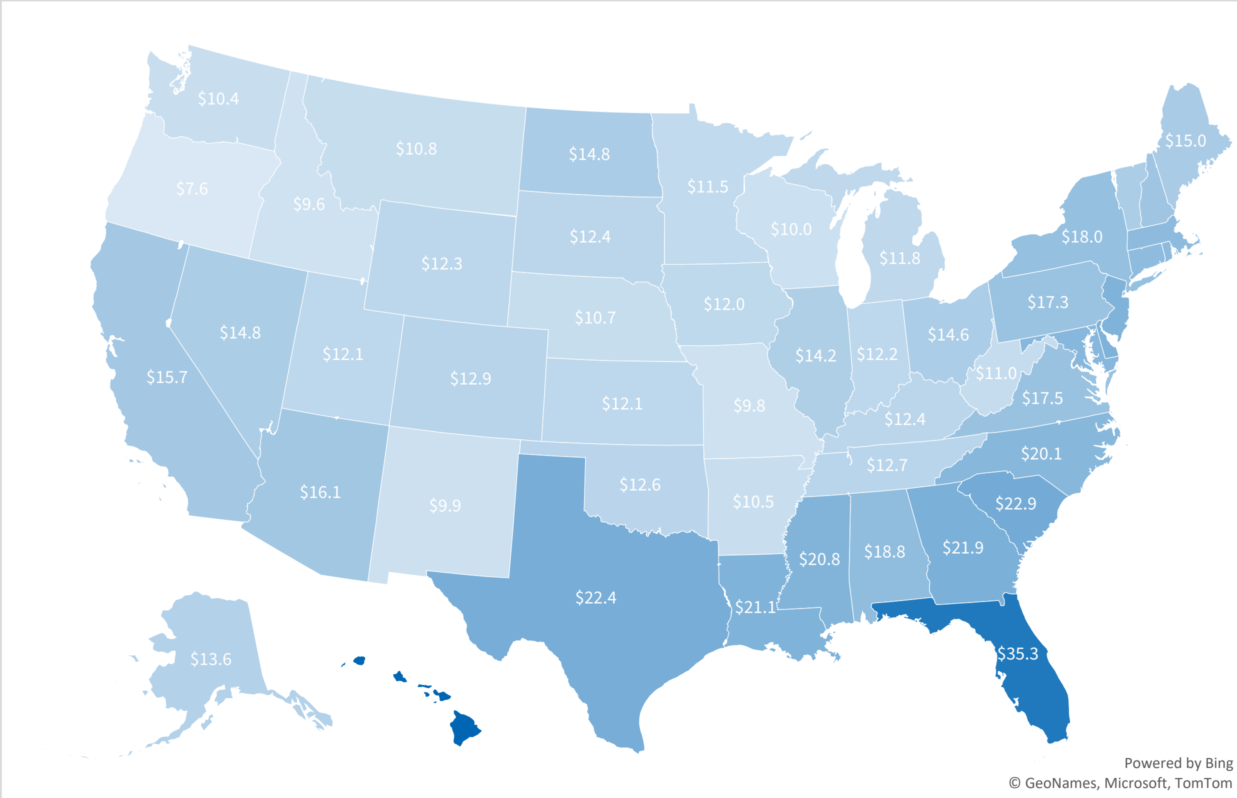
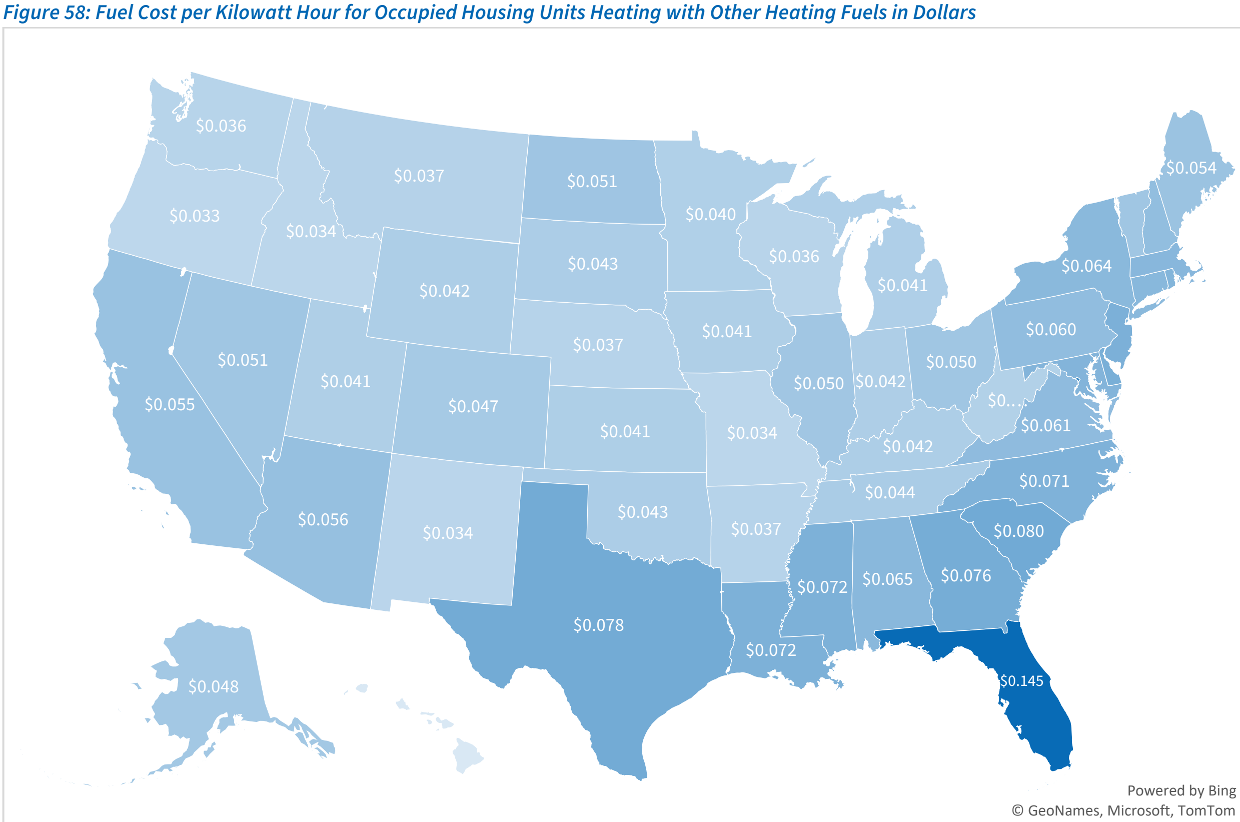


Figure 58: Fuel Cost per Kilowatt Hour for Occupied Housing Units Heating with Other Heating Fuels in Dollars



Non-Residential Costs

Residential, commercial, and industrial customers all pay different costs for electricity and natural gas. Industrial customers generally receive the lowest rates of the customer classes because they are large users that require singular hookups. The energy costs for industrial customers can be understood in the electricity sector as primarily transmission and generations costs, and in the natural gas sector as transmission and production costs. Residential and commercial customers, on the other hand, pay for transmission, generation/production, and the construction and maintenance of distribution infrastructure. How much of these costs falls on commercial customers and how much falls on residential customers is largely a matter of policy. Looking at Figures 59 and 68, there is a clear lack of uniformity in how distribution costs are shared between residential and commercial customers.

In Rhode Island, the commercial cost of electricity is negligibly higher than the industrial, and the residential sector is forced to pay for distribution infrastructure. Conversely, in many southern states, including Kentucky, Tennessee, Alabama, and Mississippi, there is a large spread between commercial and industrial prices, but a very small spread between commercial and residential.

Similar trends exist in natural gas costs, although which states they exist in appear uncorrelated to where they exist for electricity. It is also worth noting that there are two instances—New York and Ohio—where industrial customers pay more than commercial customers.

Non-Residential Electricity Costs

Table 7: 2020 Michigan Electricity Costs by Sector

Metric	2020 Value	2020 Rank
Residential Electricity Cost per kWh	$0.160	11
Commercial Electricity Cost per kWh	$0.118	13
Industrial Electricity Cost per kWh	$0.075	17

As shown in Figure 61, Michigan's 11.8 cents per kilowatt-hour price of electricity for the commercial sector is relatively high compared to other states, ranking 13th highest. Figure 63 shows that Michigan's electricity price for industrial customers was 7.5 cents per kilowatt hour and Michigan ranked 17th in overall industrial-sector electricity price. Figures 62 and 64 show that Michigan's commercial-sector electricity price is the highest among its peer states, whereas Michigan's industrial-sector electricity price is lower than in Wisconsin and Minnesota, but higher than in other midwestern states.

Figure 60 shows the comparative pricing by sector of different utilities across Michigan. It is interesting to note that, for some smaller municipal and cooperative utilities, the normal logic of price increasing from industrial to commercial to residential is not always the case.

Figure 59: 2020 Cost per Kilowatt Hour by Sector

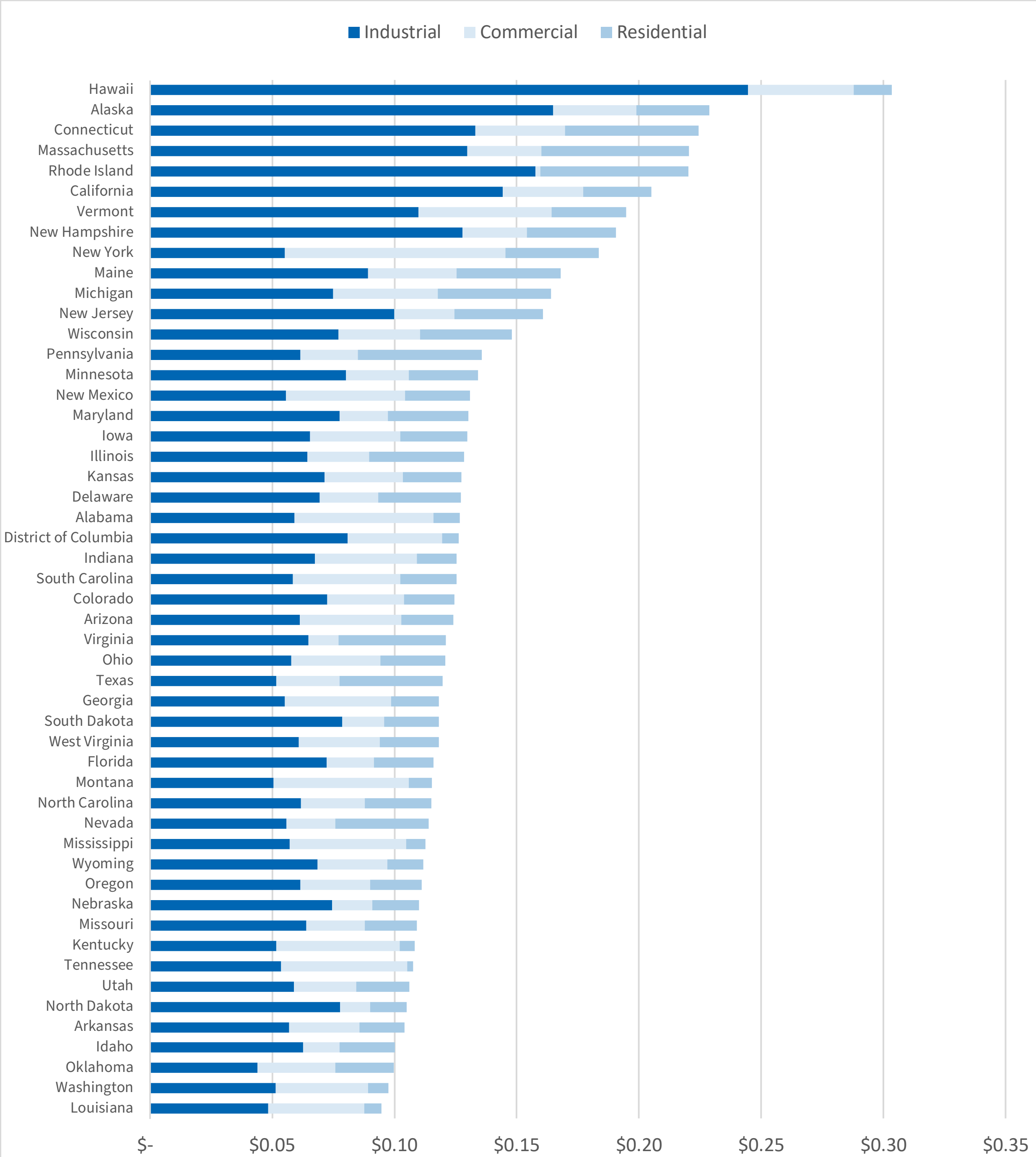


Figure 60: 2019 Electricity Price by Sector for Michigan Electric Utilities

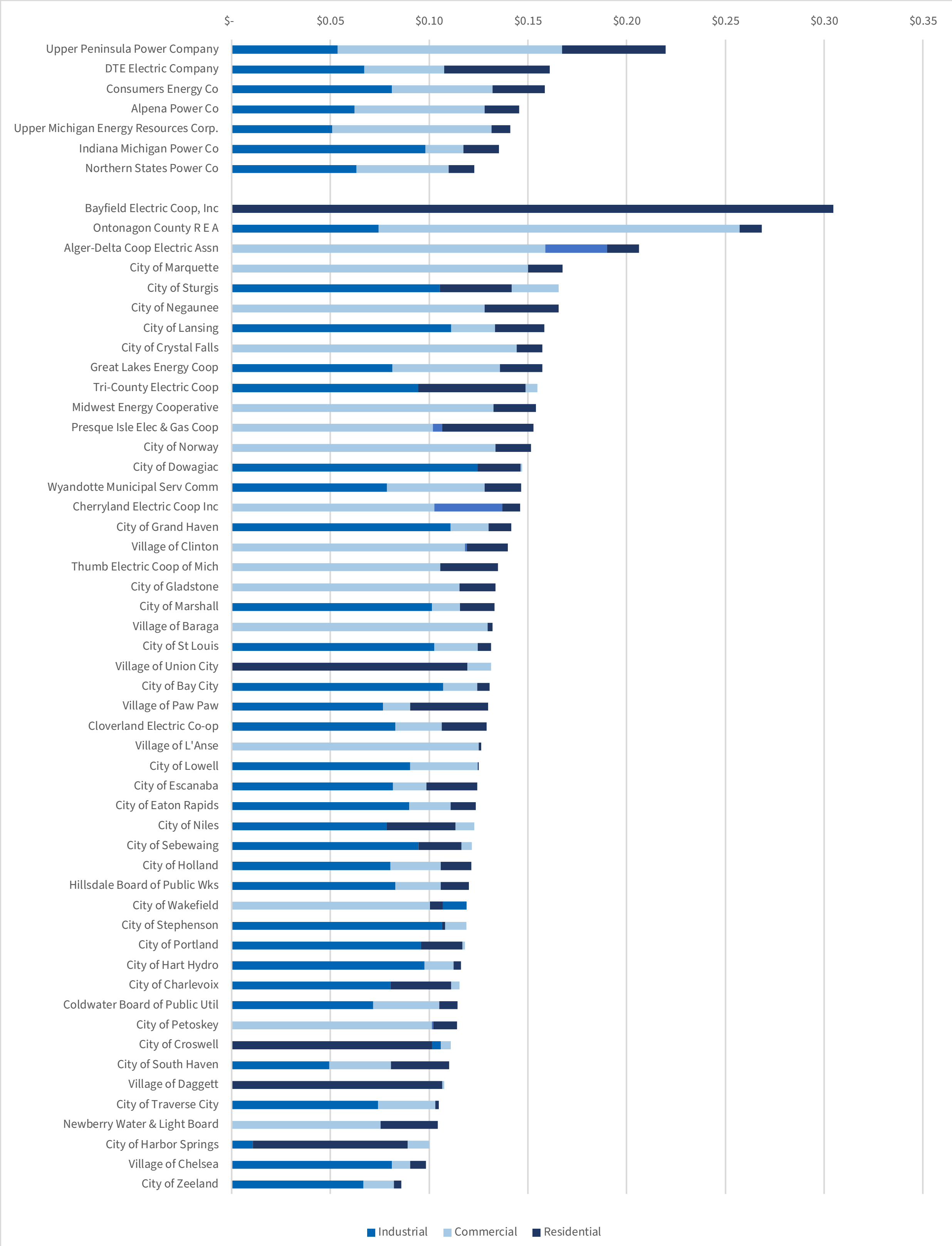


Figure 61: 2020 Cost per Kilowatt Hour of Electricity in the Commercial Sector

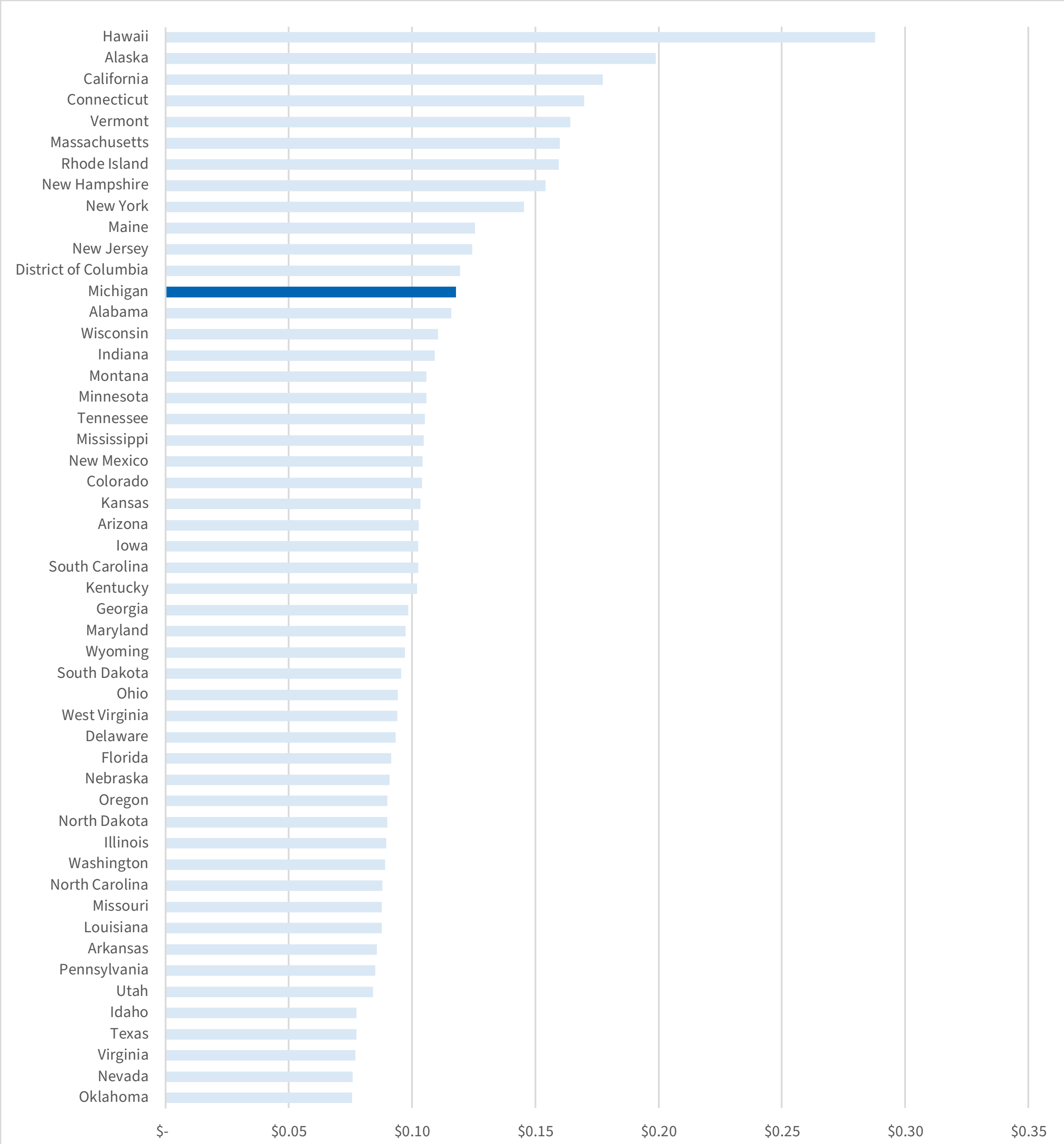


Figure 62: 2020 Cost per Kilowatt Hour of Electricity in the Commercial Sector in Dollars

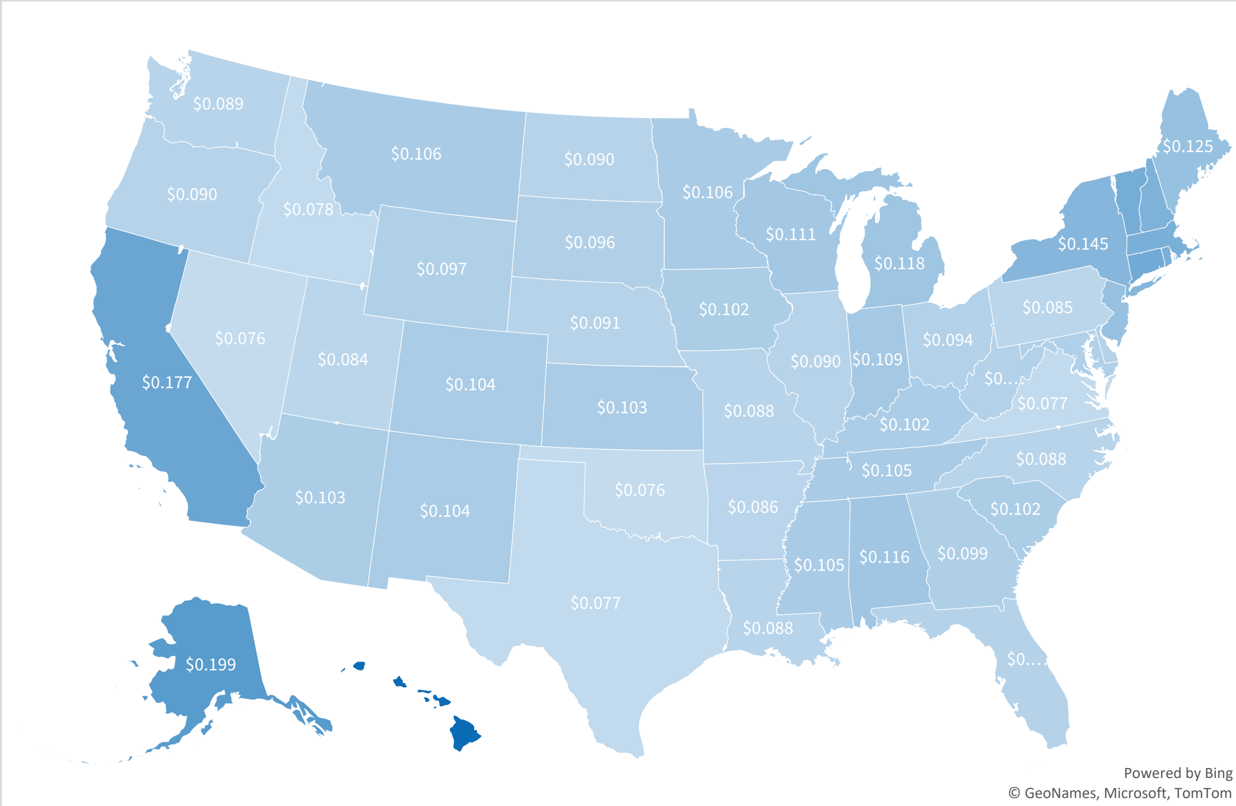


Figure 63: 2020 Cost per Kilowatt Hour of Electricity in the Industrial Sector

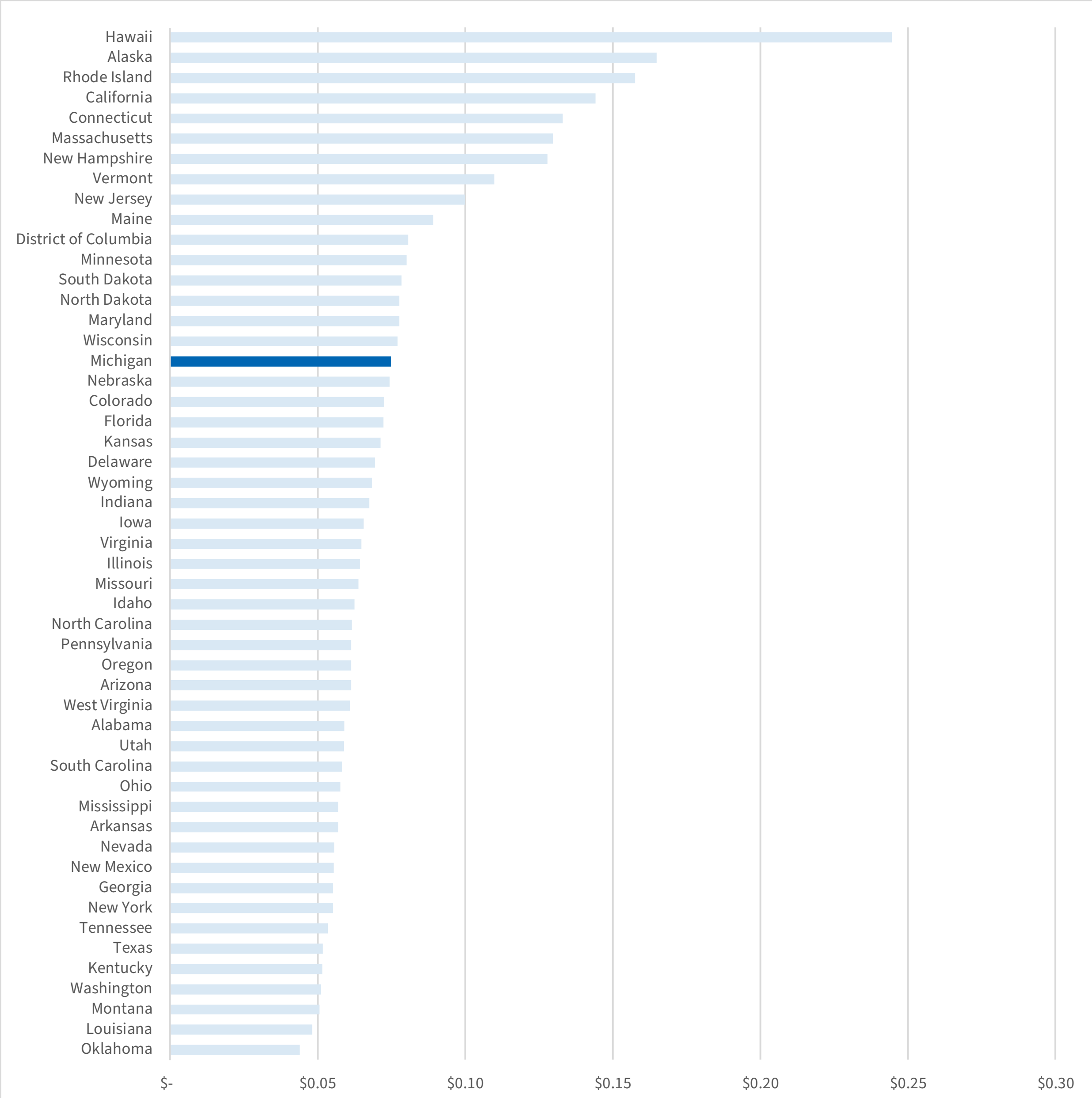


Figure 64: 2020 Cost per Kilowatt Hour of Electricity in the Industrial Sector in Dollars

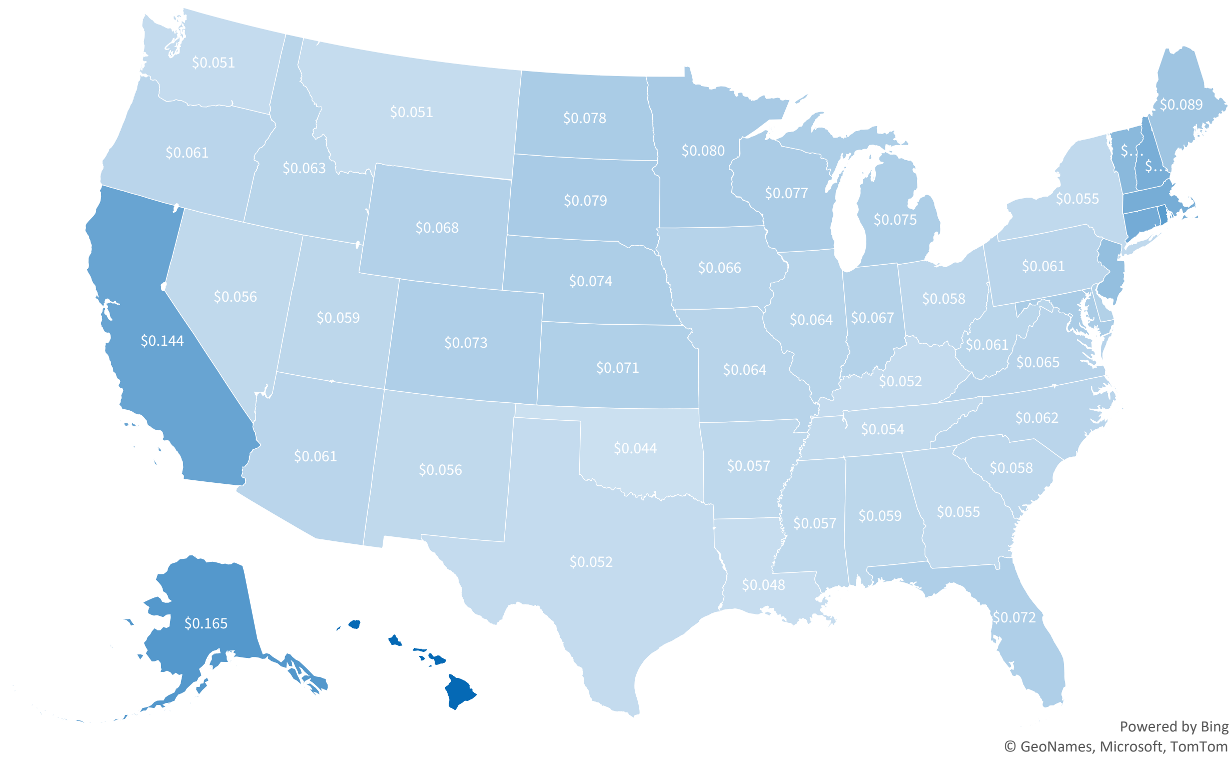


Figure 65: 2019 Cost per Kilowatt Hour of Electricity in the Commercial Sector for Michigan Utilities

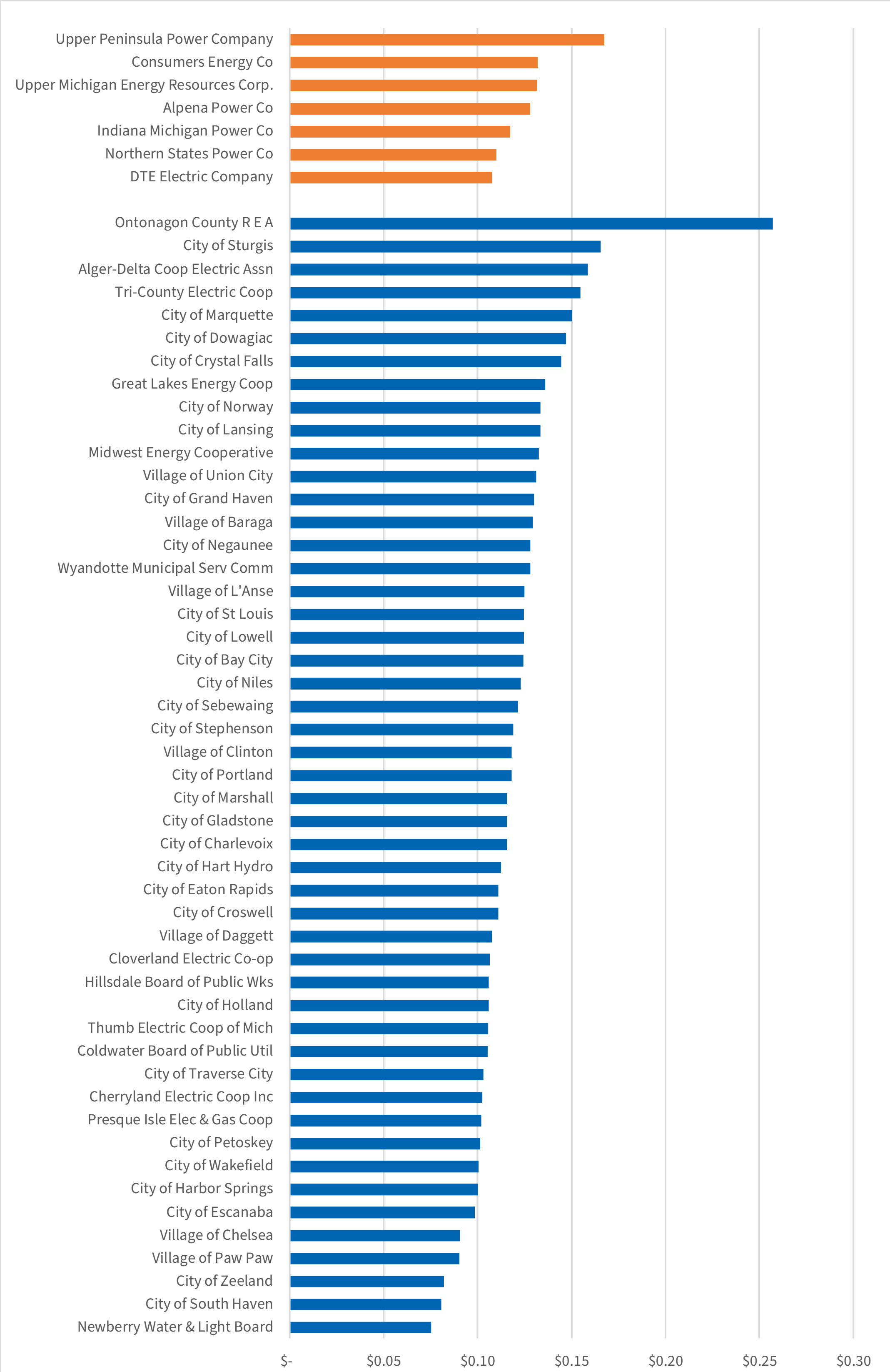


Figure 66: 2019 Cost per Kilowatt Hour of Electricity in the Industrial Sector for Michigan Utilities

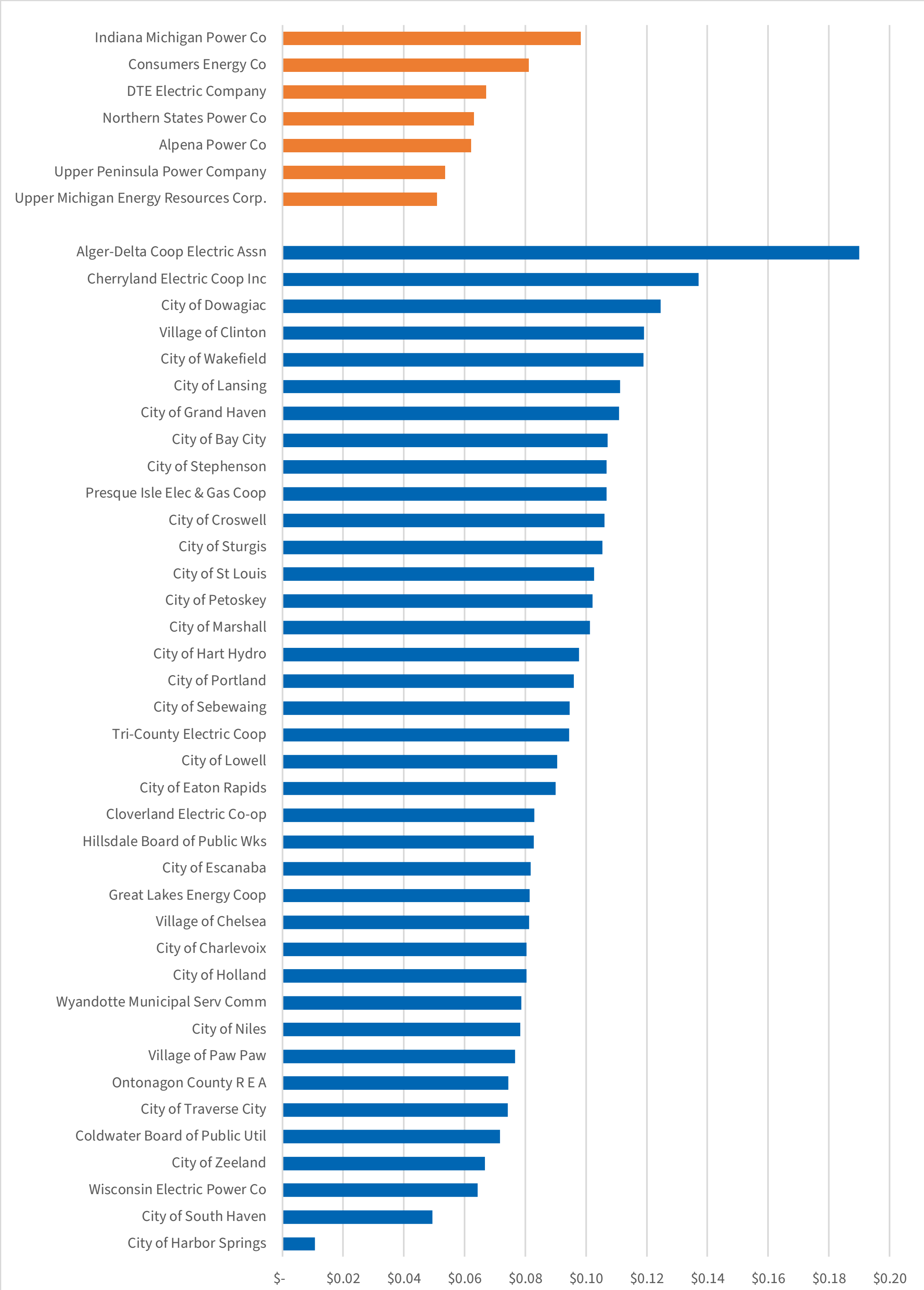
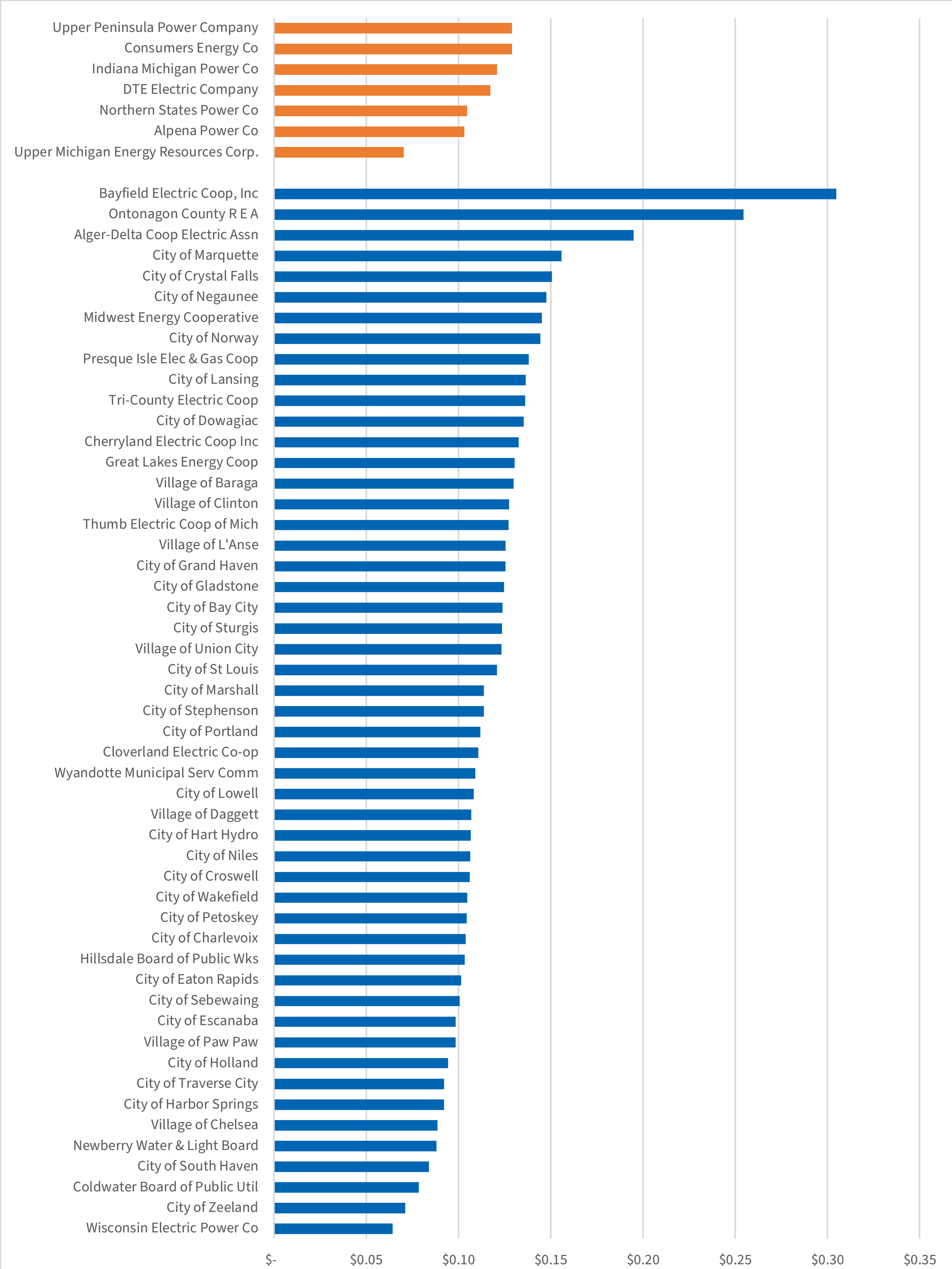


Figure 67: 2019 Cost per Kilowatt Hour of Electricity Across All Sectors for Michigan Utilities



Non-Residential Natural Gas Costs

Table 8: 2019 Natural Gas Costs by Sector

Metric	2019 Value	2019 Rank
Residential Natural Gas Cost per Therm	$0.810	39
Commercial Natural Gas Cost per Therm	$0.681	37
Industrial Natural Gas Cost per Therm	$0.601	18

As shown in **Figure 69**, Michigan's 86.1 cents per therm price of natural gas for the commercial sector is relatively low compared to other states, ranking 37th highest. **Figure 71** shows that Michigan's natural gas price for industrial customers was 60.1 cents per therm and Michigan ranked 18th in overall industrial-sector electricity price, which is notably much worse than the state's rankings for commercial and residential natural gas price. **Figures 70 and 72** show that Michigan's commercial-sector electricity price is comparable to that of its peer states, whereas Michigan's industrial-sector electricity price is higher than all of its peers, except Ohio.

Figure 68: 2019 Cost Per Therm and Kilowatt Hour of Natural Gas by Sector

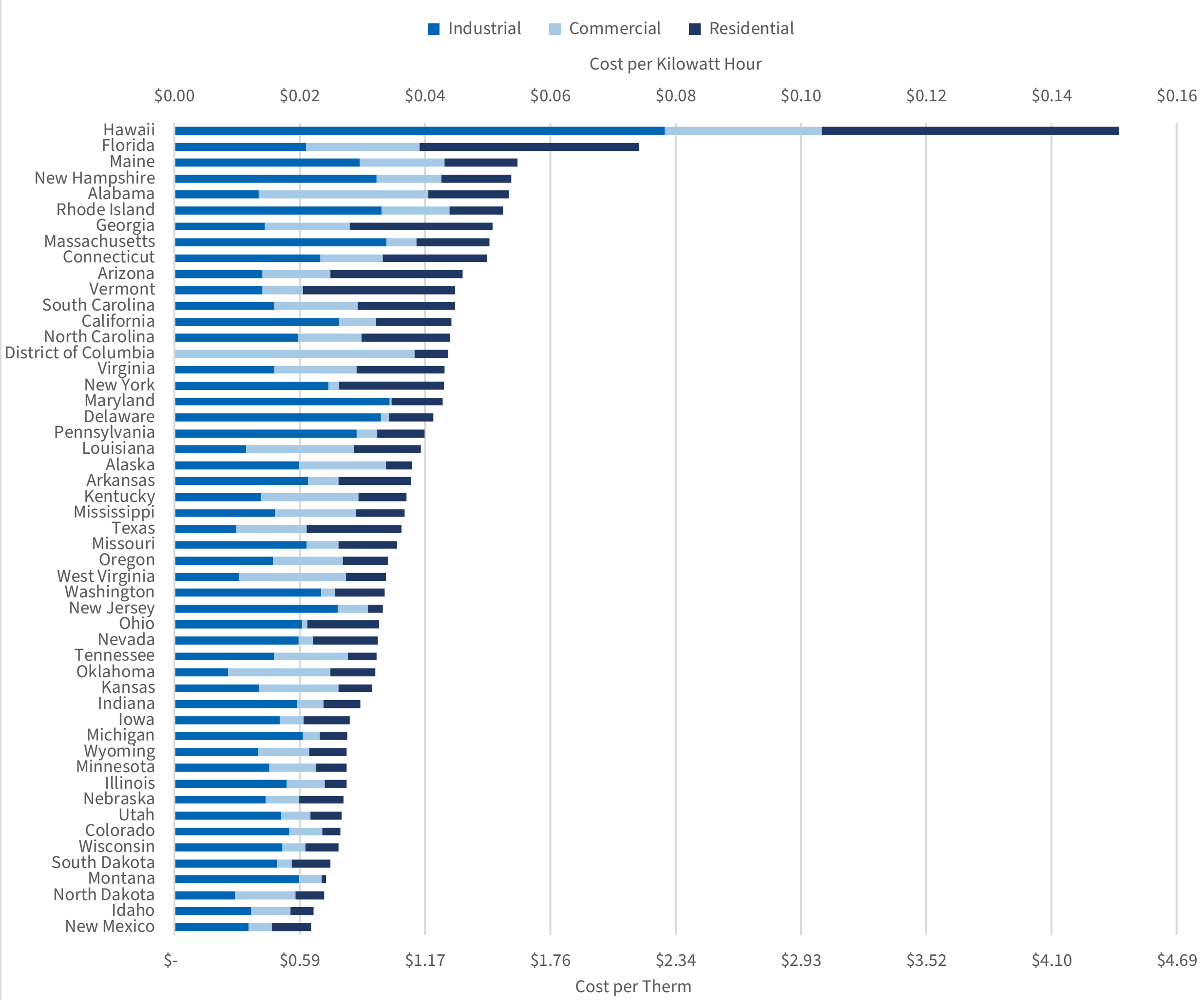


Figure 69: 2019 Cost per Therm and Kilowatt Hour of Natural Gas in the Commercial Sector

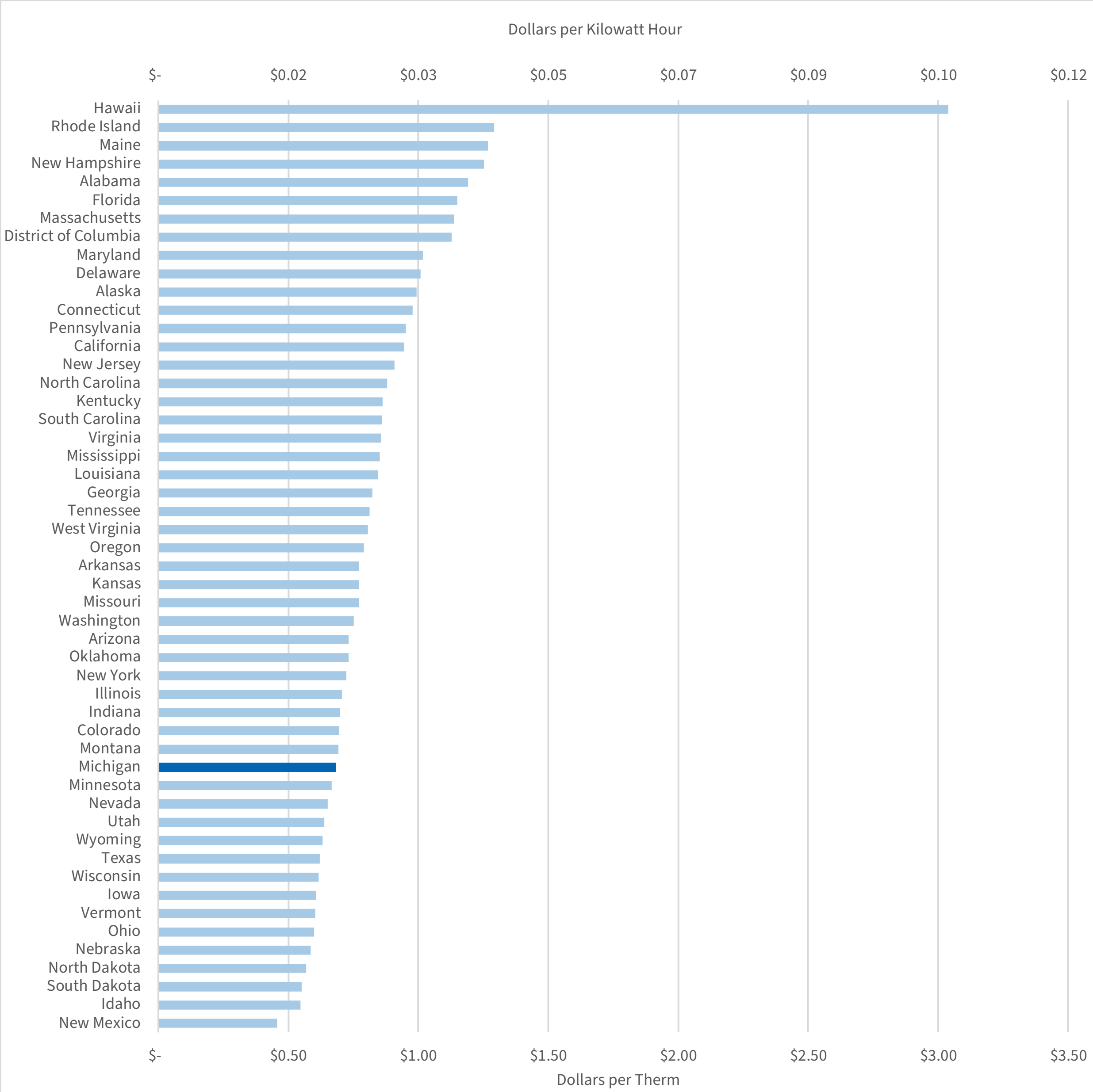


Figure 70: 2019 Rate per Therm of Natural Gas in the Commercial Sector

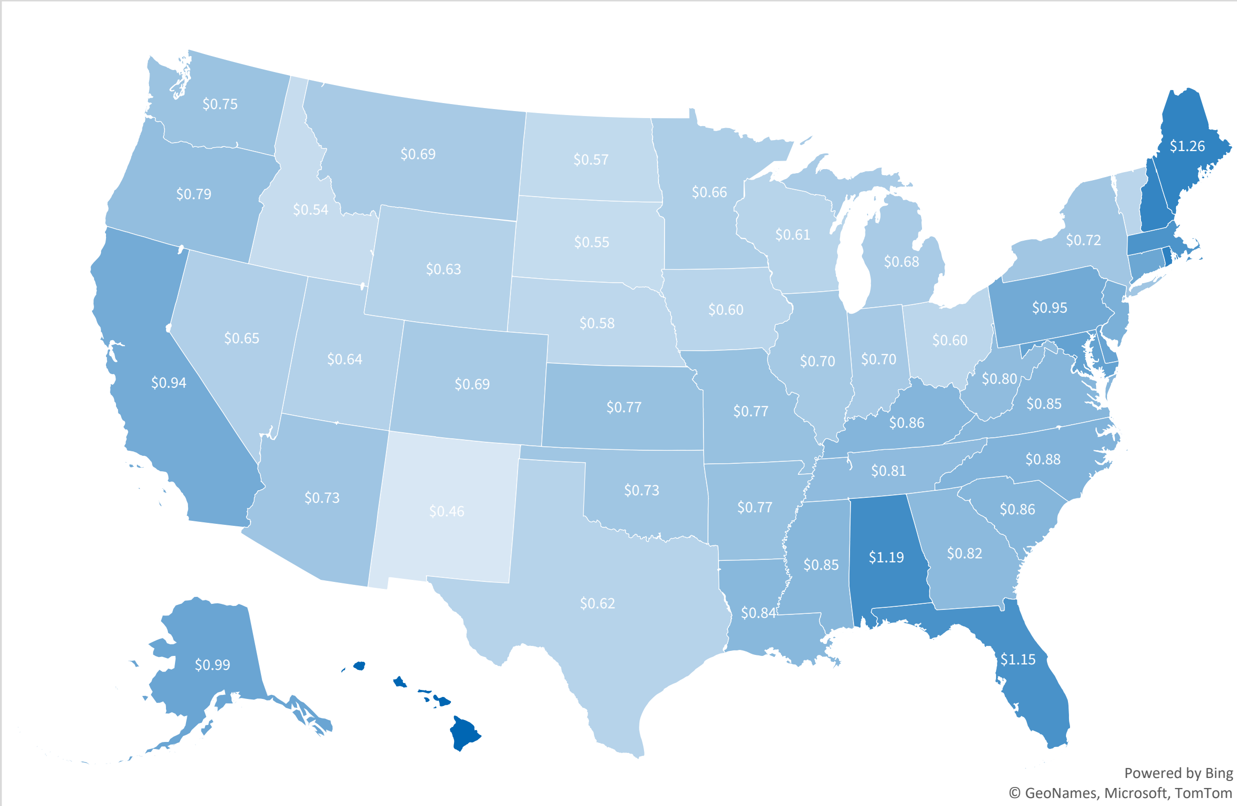


Figure 71: 2019 Cost per Therm and Kilowatt Hour of Natural Gas in the Industrial Sector

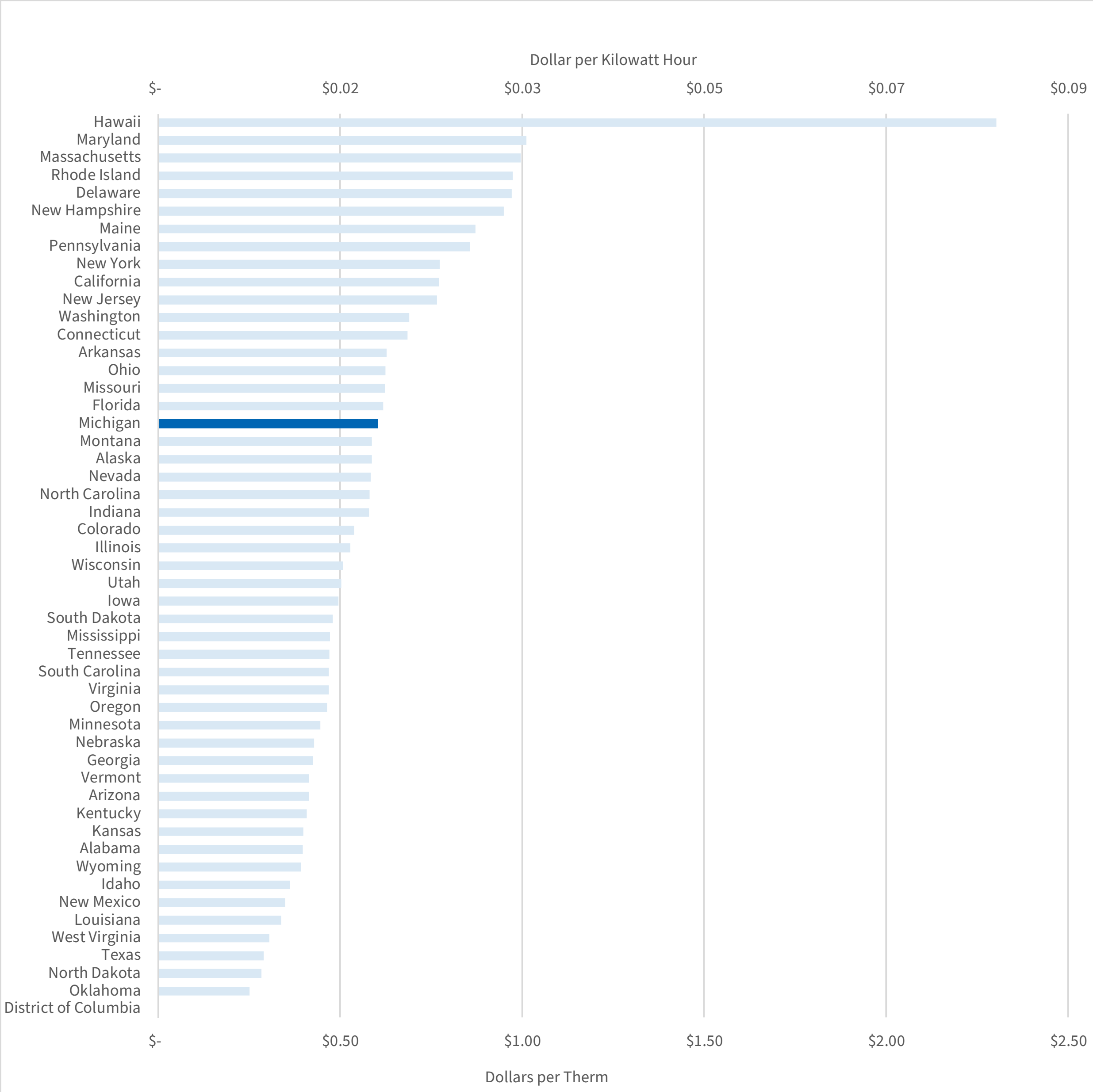
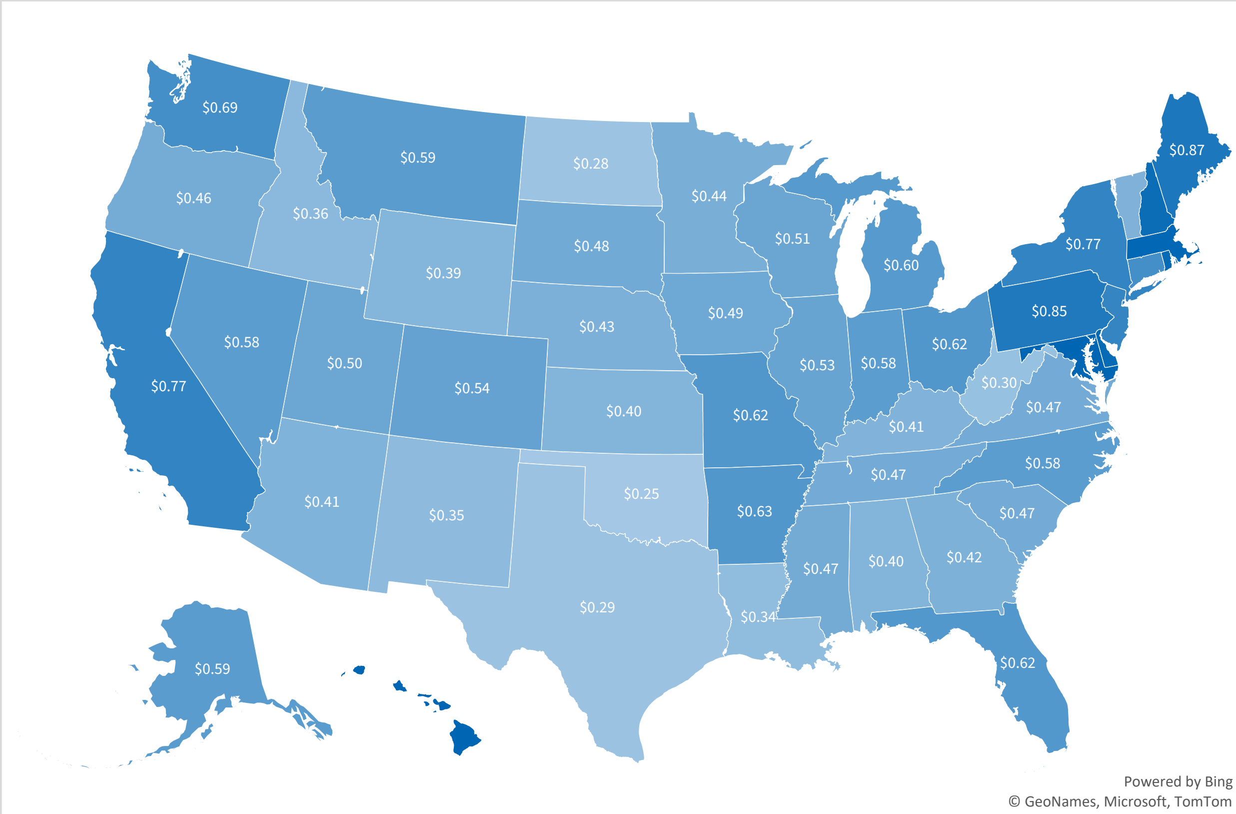


Figure 72: 2019 Cost per Therm of Natural Gas in the Industrial Sector in Dollars



ELECTRICITY GENERATION

Electricity is the most important form of energy in the contemporary era because of its diverse uses—it powers our electronics and lighting, cools our homes, and, most recently, fuels many of our vehicles. Unfortunately, there are externalities from electricity generation that affect both our immediate health and our environment. The mitigation of these externalities is crucial to the prevention of the worst effects of climate change. This section explores trends in the sources of and externalities from electricity generation, and comprises the following subsections:

- Overview
- Electricity Sources
- Emissions from Electricity Generation
- Water Use by Electricity Generators

Overview

Most states generate and use different amounts of electricity. This subsection looks at which fuels power electricity generation in states and the following subsection—*Electricity Sources*—looks at the sources that generate the electricity sold in states. Figure 73 shows eleven different forms of electricity generation for which the EIA reports data, but does not include any behind-the-meter or small-scale solar generation, which currently only account for small percentages of states' energy mixes. The sources displayed are:

- Hydroelectric
- Utility-Scale Solar
- Wind
- Geothermal
- Nuclear
- Biomass
- Petroleum Coke
- Other Gases
- Coal
- Natural Gas
- Petroleum Liquids

Figures 75 and 76 are maps of states' generation mixes by renewable and clean resources. Renewable resources are defined as: hydroelectric, utility-scale solar, wind, geothermal, and biomass. The definition of clean resources adds nuclear to that list while excluding biomass. Biomass is included as a renewable resource because it comprises a variety of organic sources that can be regrown. However, biomass is not considered a clean resource because, while it is technically net zero emissions, it produces substantial emissions when burned, which may contaminate the atmosphere locally.

The data in this section comes from the EIA's SEDS databases.

Table 9: 2020 Electricity Generation Overview

Metric	2020 Value	2020 Rank
Percentage of Electricity Generated by Renewable Resources	10.4%	19
Percentage of Electricity Generated by Clean Resources	37.2%	26
Fuel Source with the Largest Share of Generation Mix	Natural Gas	

At 10.4%, Michigan is in the bottom half of states for electricity generated by renewables. However, because of Michigan's substantial nuclear power industry, it ranks exactly in the middle of states in terms of clean energy production at 37.2%. The largest source of generation in Michigan is natural gas at 32.6%, followed by coal at 26.5%.

Figure 73: 2019 Electricity Generation by Type as a Percentage of Energy Mix

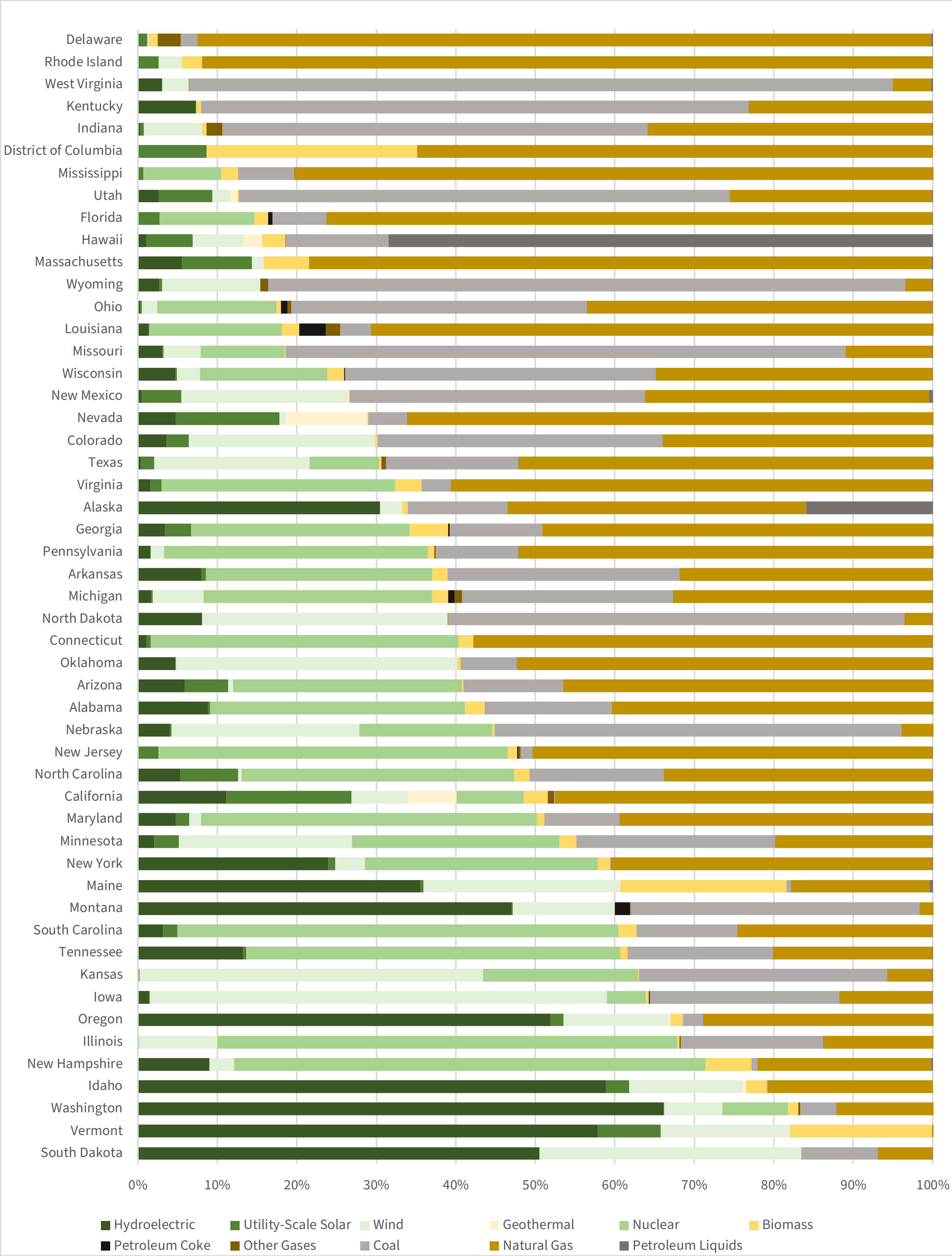


Figure 74: 2020 Fuel Source with Largest Share of Current Generation Mix

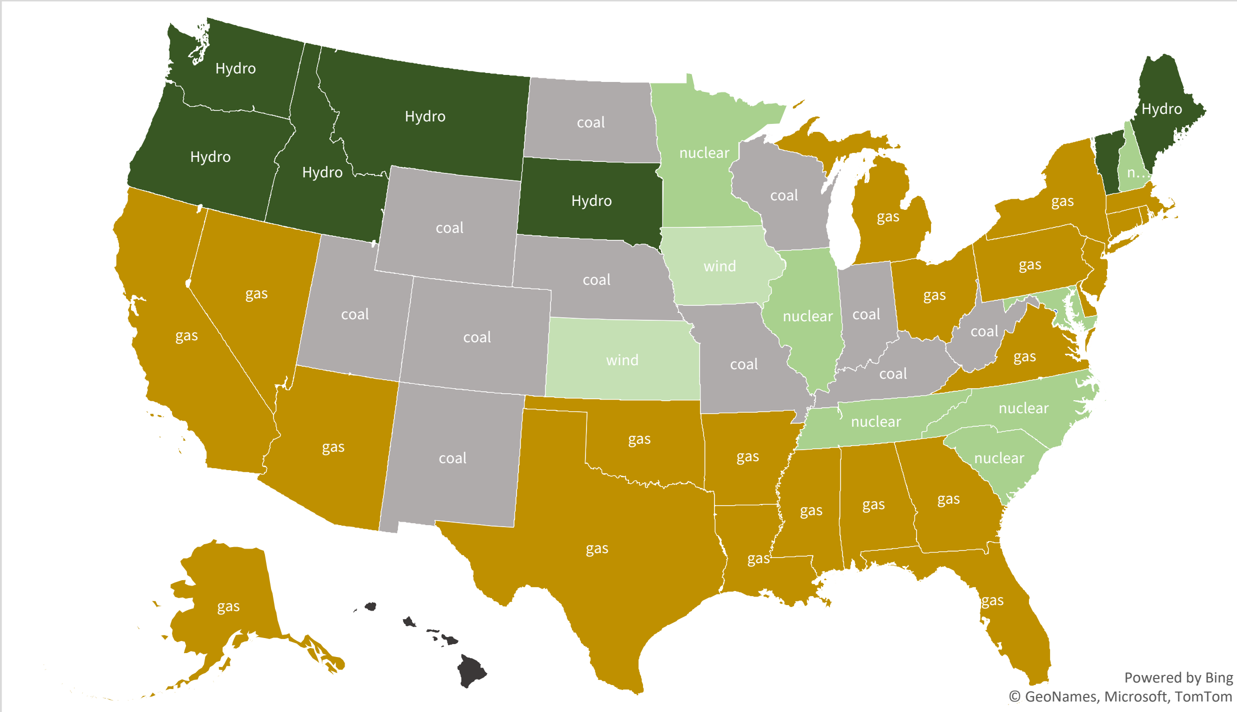


Figure 75: 2020 Percentage of Generation Produced by Renewable Resources

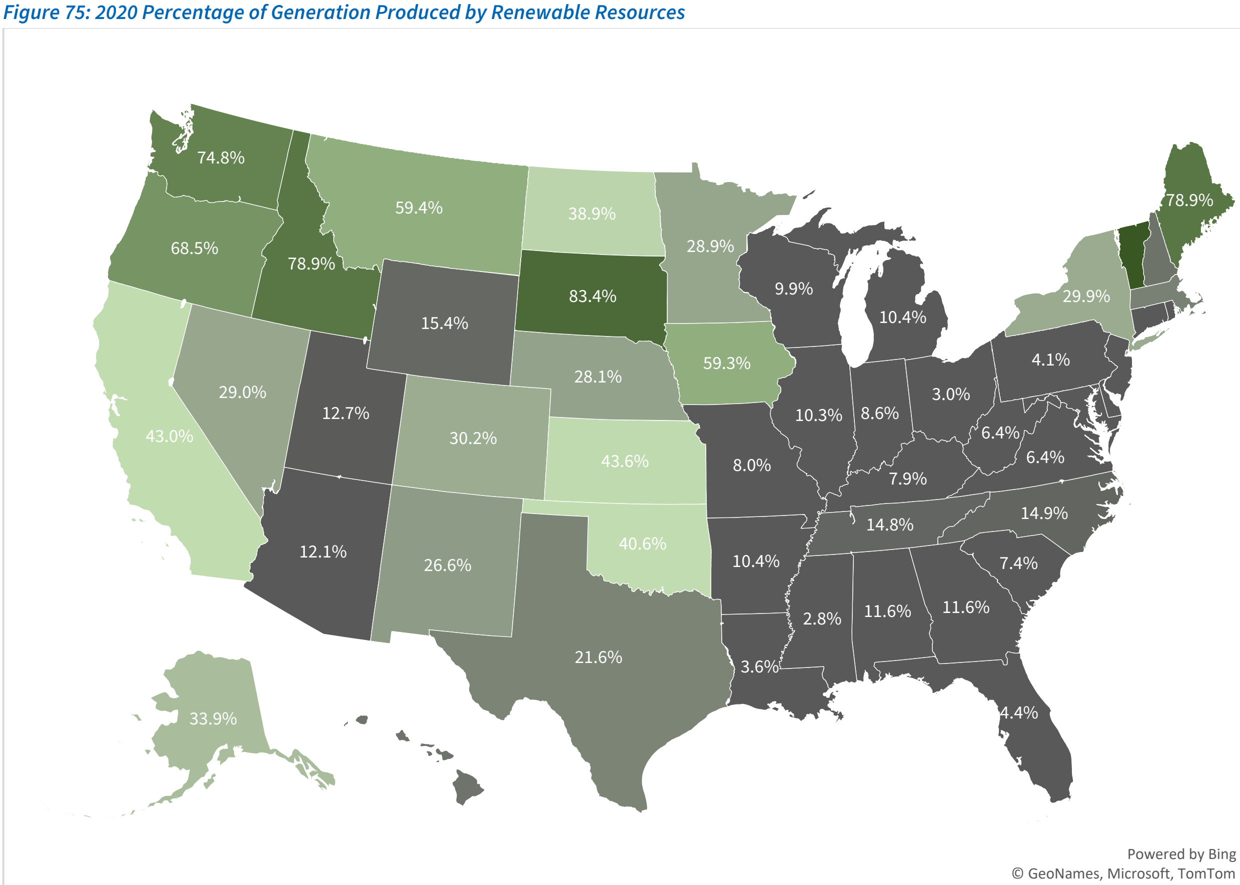
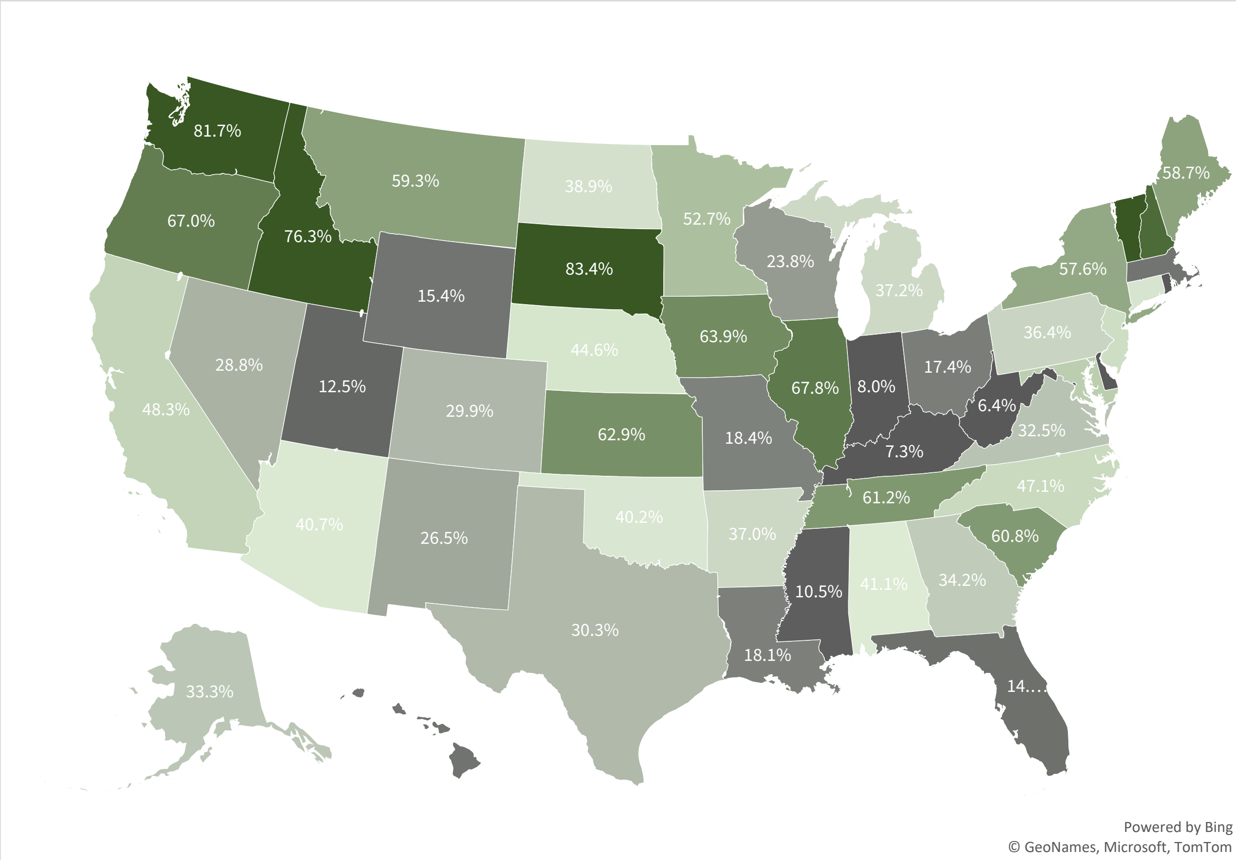


Figure 76: 2020 Percentage of Generation Produced by Clean Resources



Electricity Sources

The electricity grid interconnects states and generation resources such that at any given time a home, business, or manufacturer cannot know precisely where their electricity is coming from. This section looks at the sources of electricity that power states—which states are large exporters, and which are importers.

Some states with largely clean and renewable generation mixes import electricity generated with fossil fuels from out of state to meet their energy demands. This is the case for Idaho, which has a 79% renewable generation mix, but renewable generation is only 54% (Figures 75 and 83) of the state's electricity sales.

States on the US border with Canada may import hydropower across the international border, which contributes to the percentage of renewables in their electricity sales. Vermont, a small state, brings almost three times its domestic electricity needs into the state from Canada and resells that hydropower to adjacent states, making it, by percentage of in-state electricity sales, the largest electricity exporter in the country (Figure 80). However, in terms of net exports, Vermont's are trivial. The largest exporter by kWh is Pennsylvania, which exports 70 terawatt hours of electricity generated by fossil fuels, around nine times Vermont's exports (Figure 78).

Some states have legislated goals for how much electricity sold in a state must or should come from renewable or clean resources. The most rigorous of these standards are renewable portfolio standards (RPS), which mandate that a portion of a states' electricity sales *must* come from renewable resources, while less stringent are "clean energy standards," "renewable portfolio goals," and "clean energy goals." "Goals" are non-binding standards, and "clean energy" may refer to a variety of energy resources, but the largest non-renewable clean energy source is nuclear. The scale and speed of these standards and goals varies dramatically between states. The current scope of clean and renewable energy requirements is well represented in a map published in 2020 by the Database of State Incentives for Renewables and Efficiency (Figure 82).

The data in this section come from two EIA sources: the SEDS database and state electricity profiles, the latter of which provides information on state electricity disposition necessary to produce Figures 77 and 83-86.

Table 10: 2019 Electricity Generation Overview

Metric	2019 Value	2019 Rank
Interstate Imports and Exports in TWh (Higher Rank Implies More Exports)	10.1	38
Interstate Imports and Exports as a Percentage of Sales (Higher Rank Implies More Exports)	10.0%	30
Renewable Generation as a Percentage of Sales	11.5%	26
Clean Generation as a Percentage of Sales	39.6%	24

Michigan is the 13th largest exporter of electricity in the country by volume, and the 21st largest by percentage of sales. Because renewable and nuclear generation are used as base load, this implies that under most market conditions Michigan's electricity exports are from fossil generation, which in turn means that the percentage of in-state sales provided by renewable and clean generation are noticeably higher than the percentage of generation produced by these resources at 11.5% and 39.6% respectively (*see section overview for comparison*).

Michigan's current renewable portfolio standard is 15% by 2021. And while Michigan utilities are producing substantially more renewable energy in 2021 than they were in 2019 (the year reported for above), they still may not be quite producing 15% of their sales from renewable sources. The technical legal requirement of the RPS standard is for electric utilities to "retire" a number of Renewable Energy Credits (RECs) each year equal to 15% of their sales.

RECs can be produced by renewable generation in the out-of-state service territories of Michigan utilities, which happens with Indiana Michigan Power and some of the Upper Peninsula utilities that get power from Wisconsin. RECs can also be banked for up to 5 years, so if they earned more than they needed in the past they can use them now. Finally, certain "bonus" RECs can be earned by utilities for using Michigan parts and labor from Michigan. These RECs are not actually attributable to renewable electricity as the EIA would report it.

Figure 77: 2019 Electricity Sales by Generation Type and Source in Millions of Kilowatt Hours

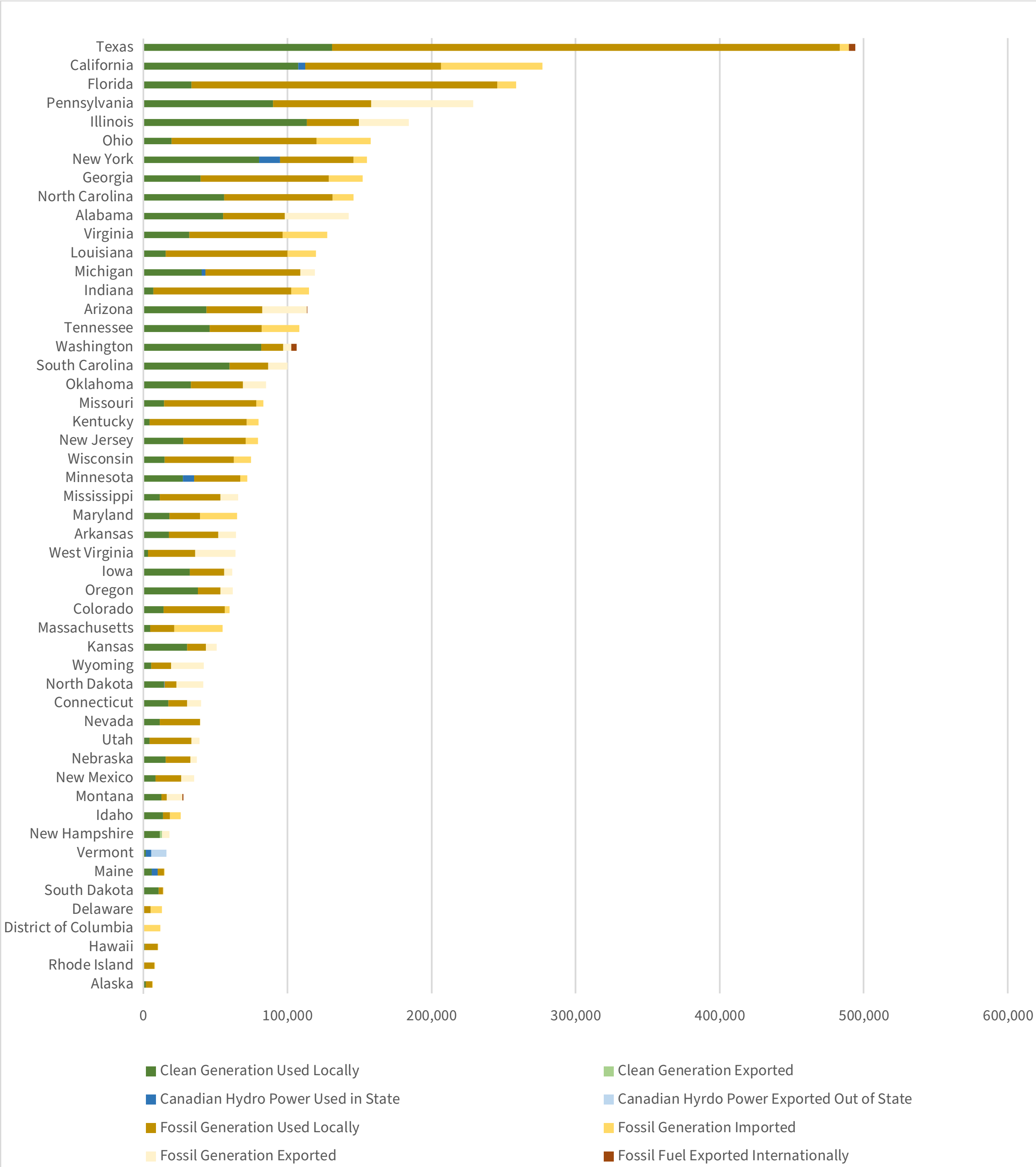


Figure 78: 2019 Interstate Imports and Exports of Electricity in Millions of Kilowatt Hours

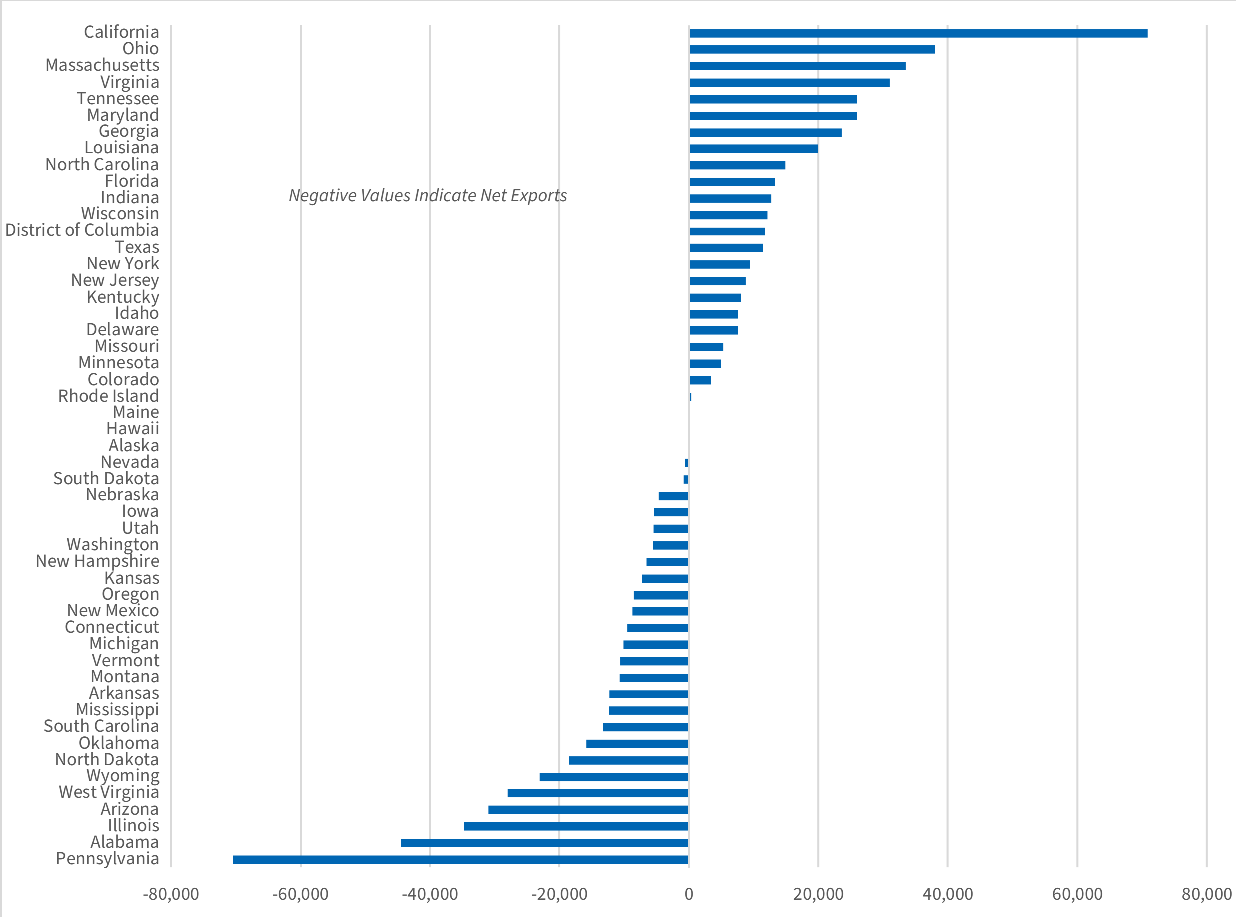


Figure 79: 2019 Interstate Imports and Exports of Electricity in Millions of Kilowatt Hours

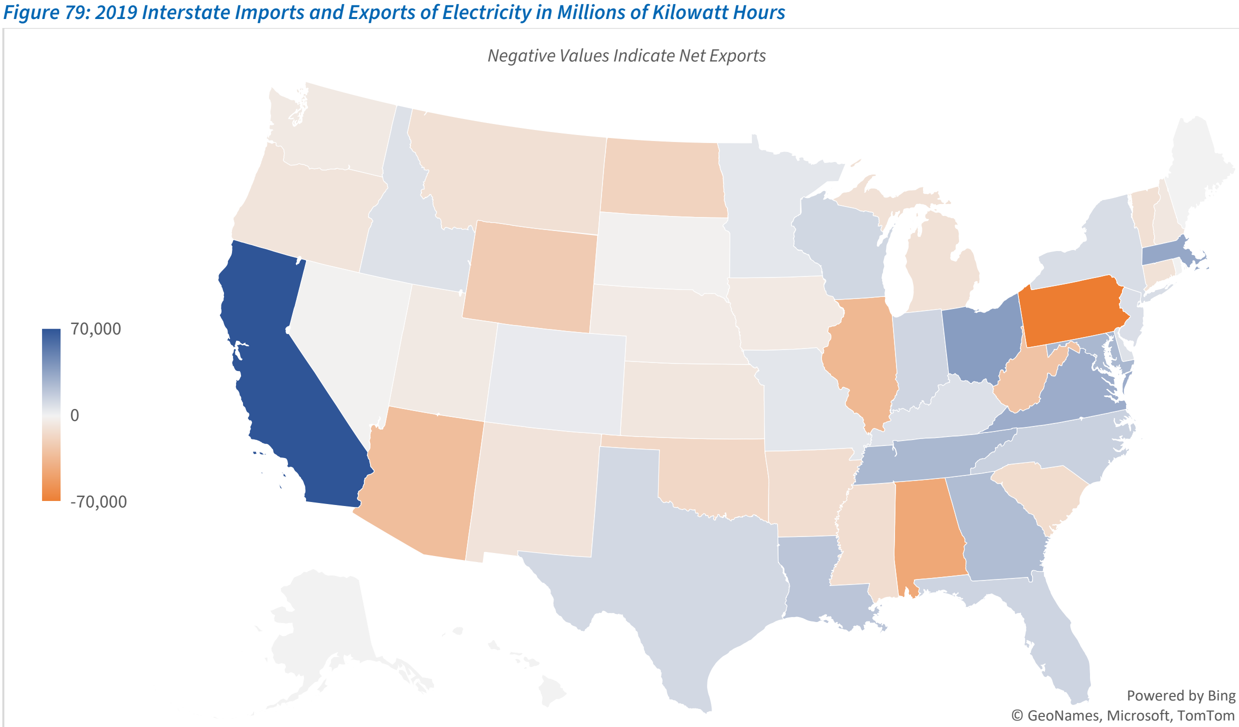


Figure 80: 2019 Interstate Imports and Exports of Electricity as a Percentage of State Sales

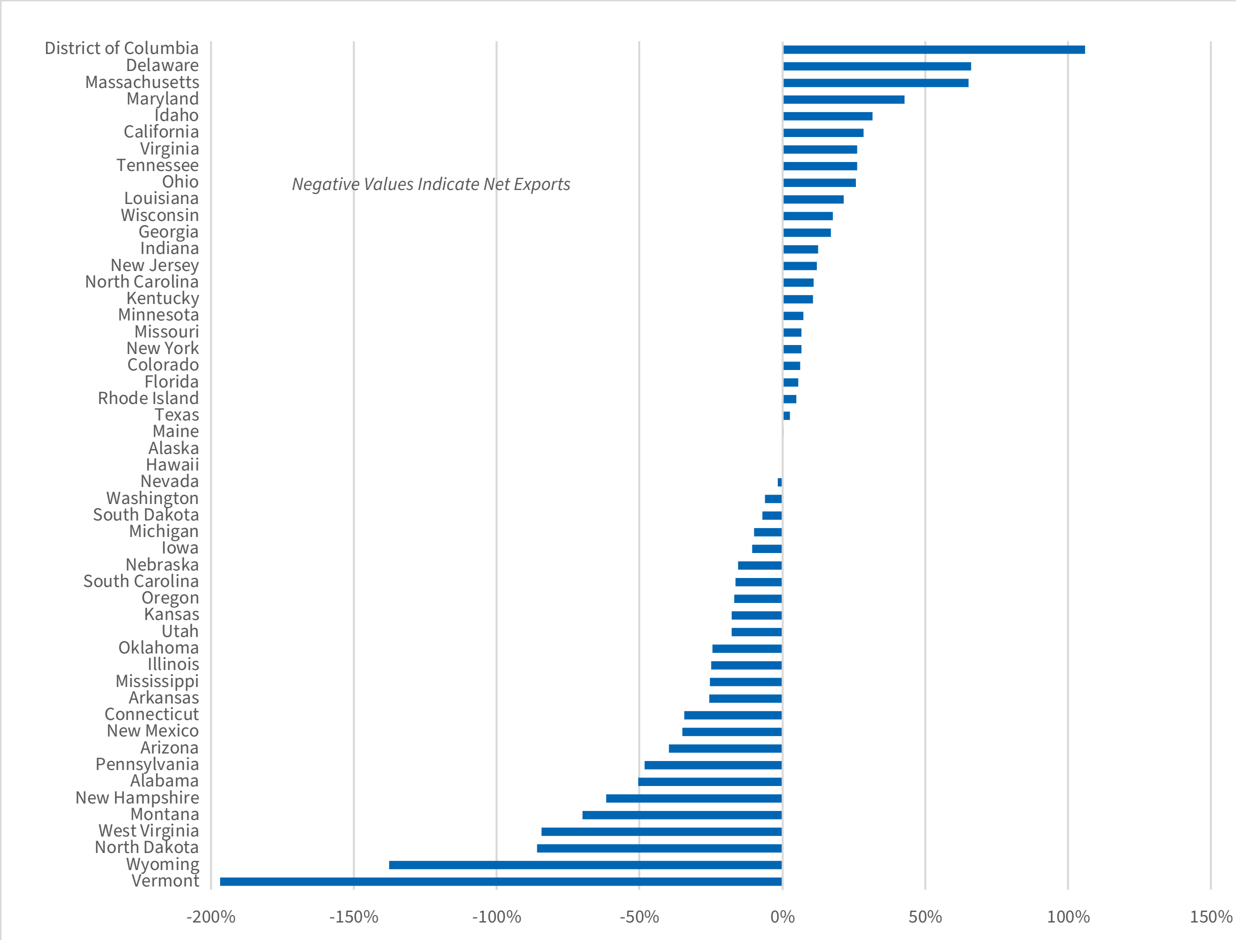


Figure 81: 2019 Interstate Imports and Exports of Electricity as a Percentage of State Sales

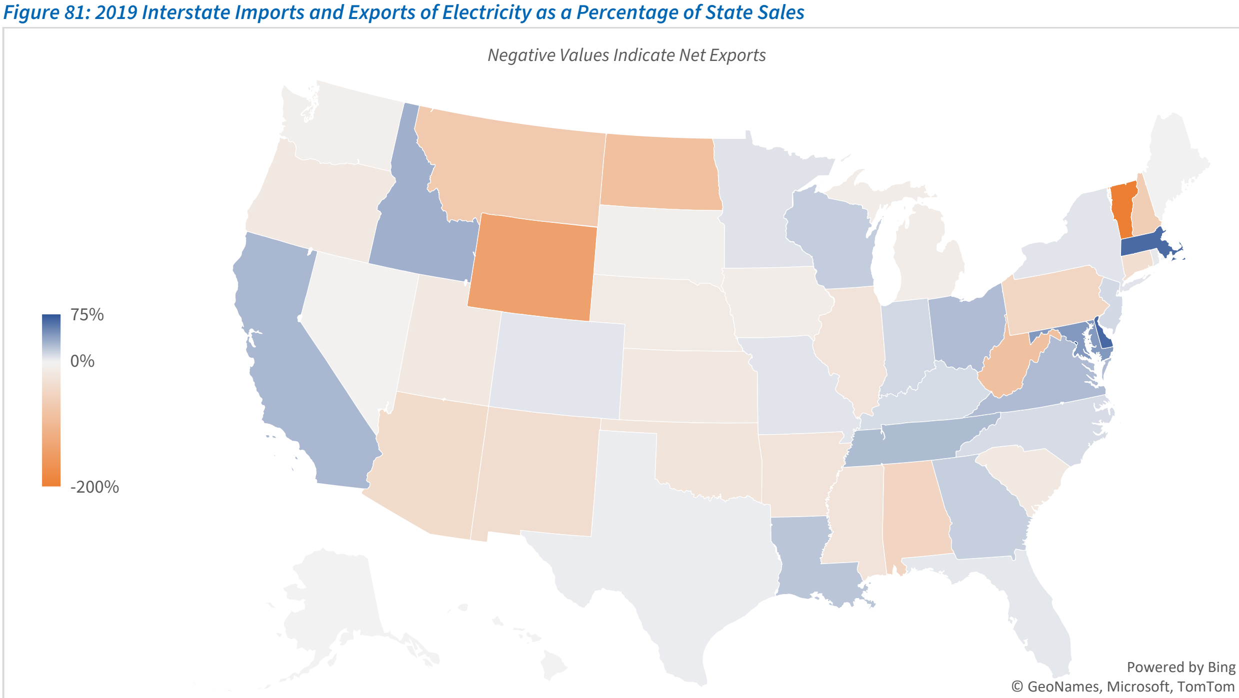
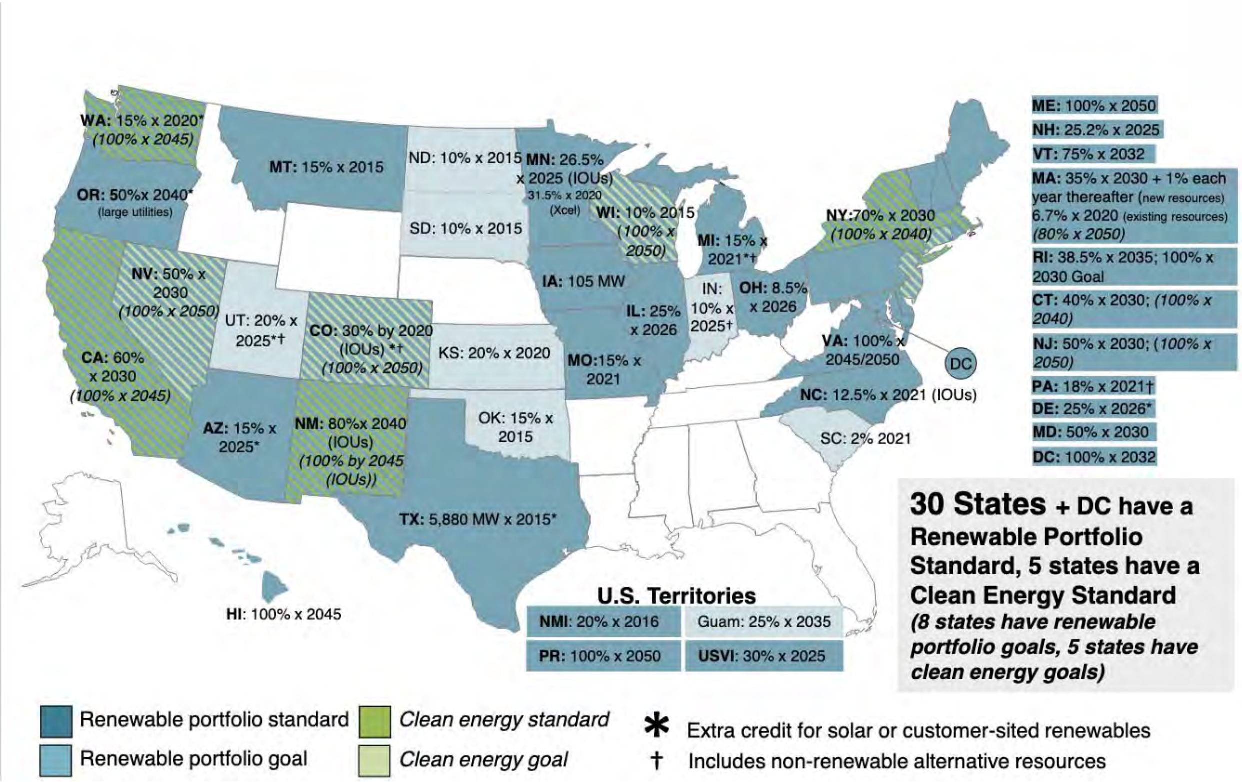


Figure 82: Renewable and Clean Energy Standards



Source Credit: DSIRE – NC Clean Energy Technology Center

Figure 83: 2019 Renewable Generation and Renewable Imports as a Percentage of State Sales

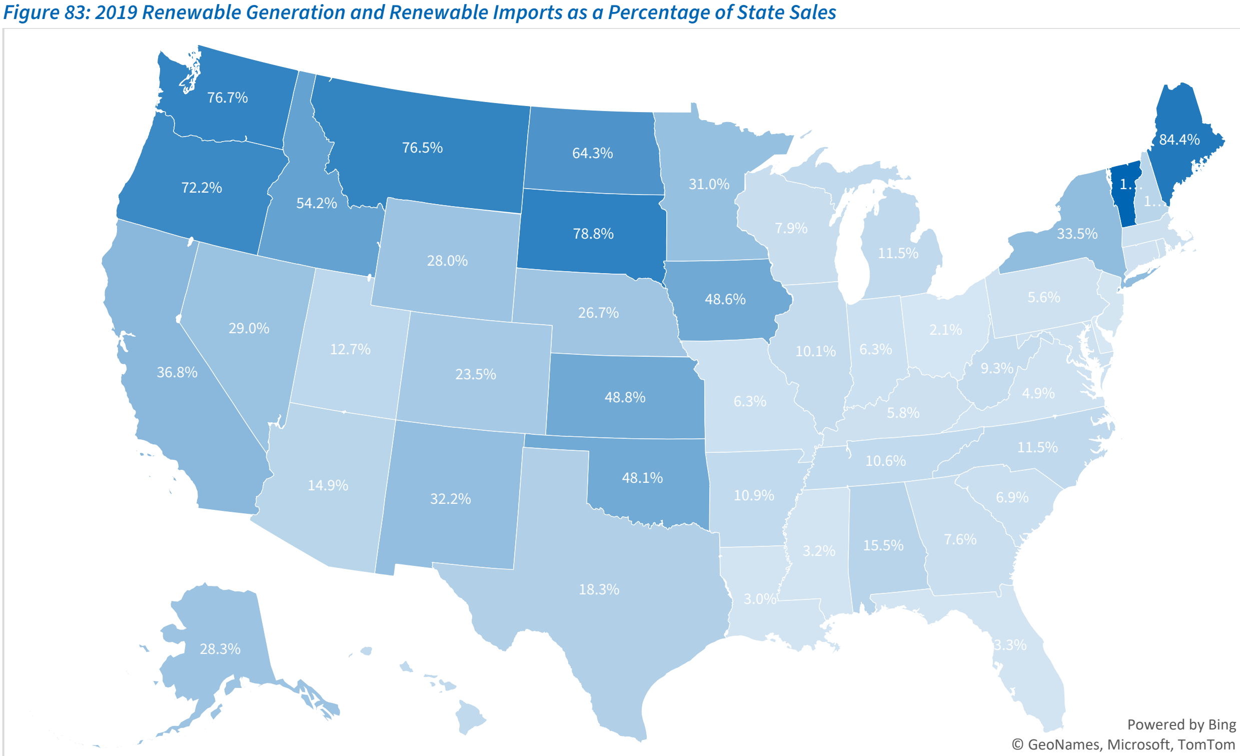


Figure 84: 2019 Clean Generation and Clean Imports as a Percentage of State Sales

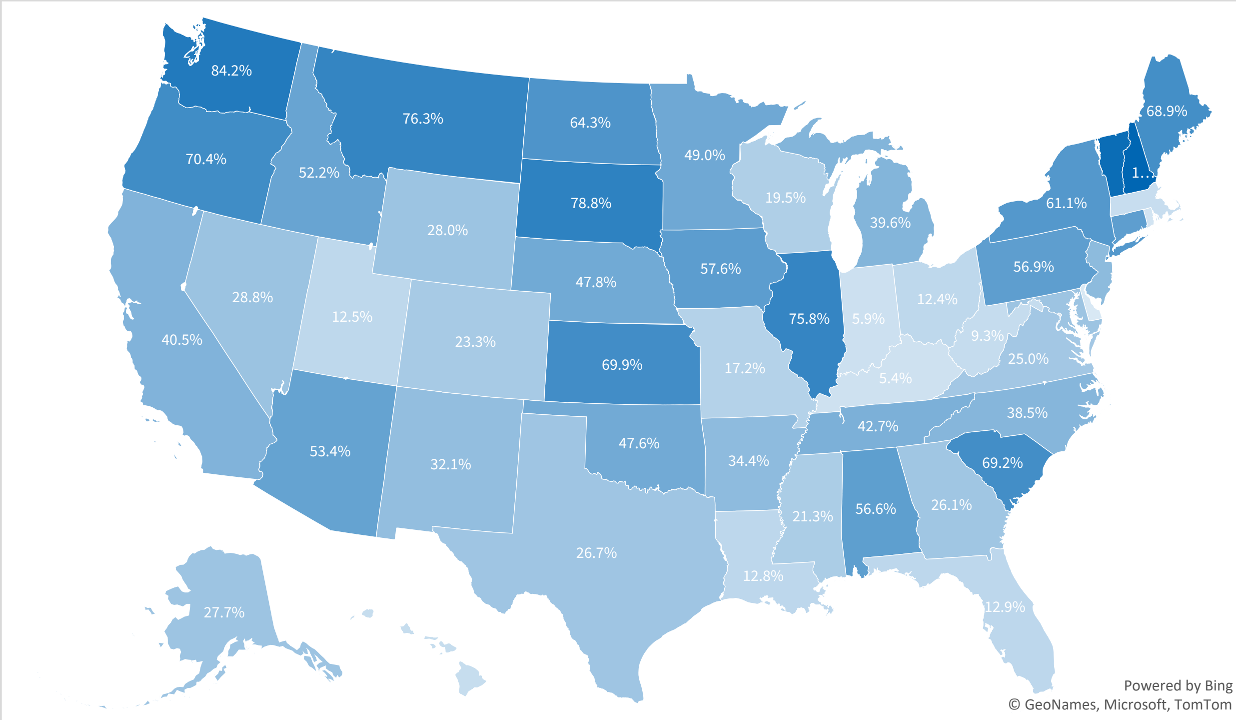


Figure 85: 2019 Fossil Generation and Fossil Imports as a Percentage of State Sales

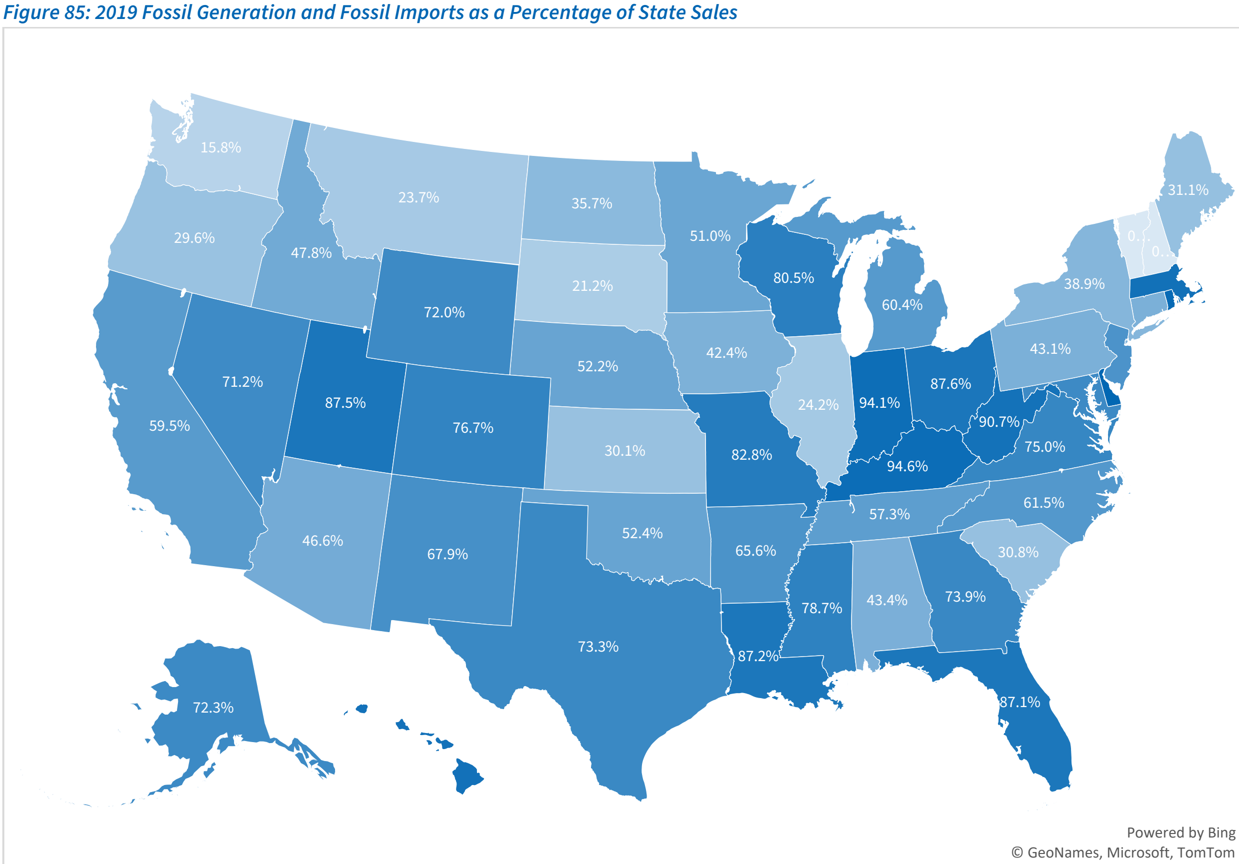
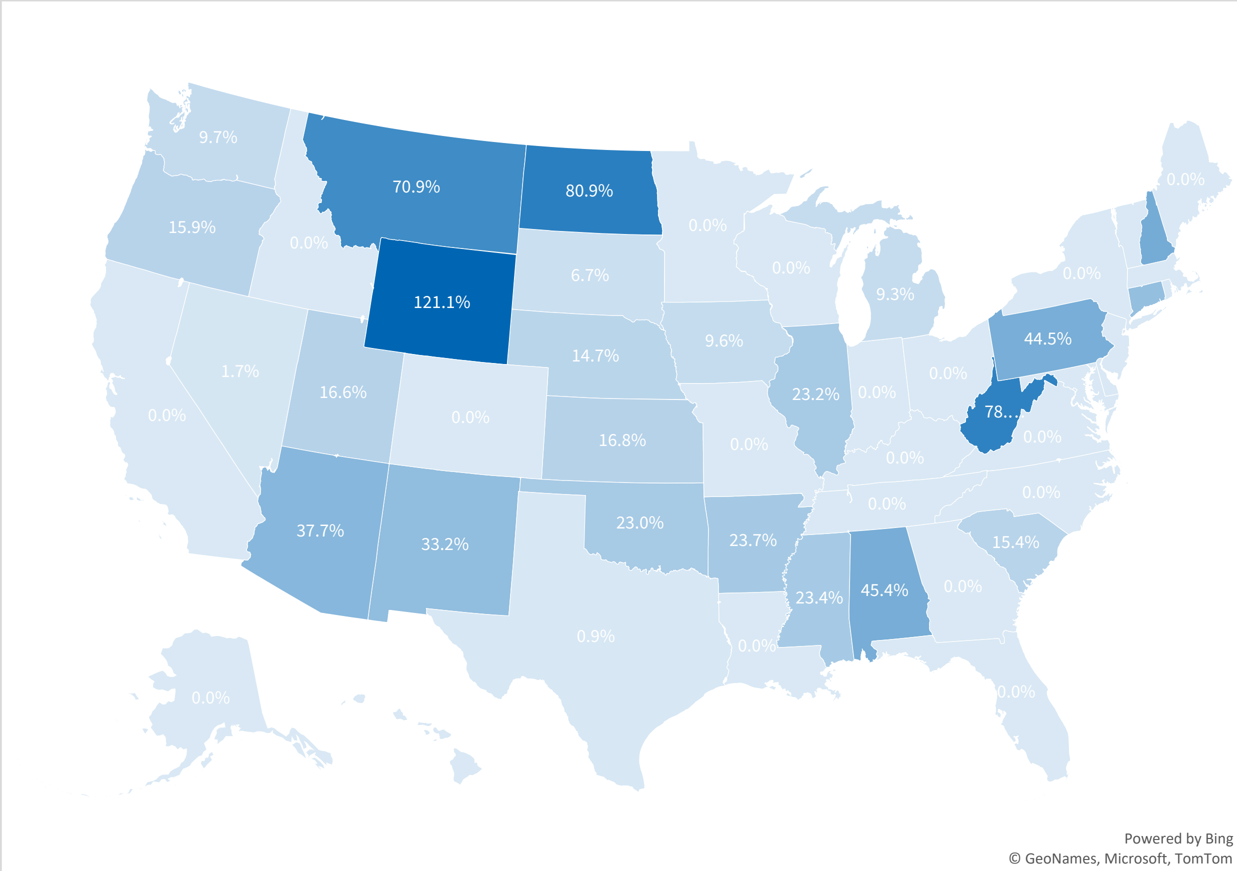


Figure 86: 2019 Exported Fossil Generation as a Percentage of State Sales



Emissions from Electricity Sources

Emissions of pollutants into the atmosphere is the most ubiquitous and most important pathway through which power generation affects the environment. Power plants produce many different pollutants, but the largest quantities and arguably greatest effects are from:

- carbon dioxide (CO_2), which is the principal gas causing climate change and can reduce cognitive function
- sulfur dioxide (SO_2), which causes asthma attacks, cardiopulmonary diseases, acid rain, and is a chemical precursor to formation of small particles that when breathed cause several respiratory and other problems, miscarriages, and birth defects
- nitrogen oxides (NO_x), which cause respiratory problems including wheezing, asthma, and other breathing difficulties and is a chemical precursor to formation of small particles and ozone in the air that also cause numerous health problems

Electric utilities report emissions of key pollutants from each power plant to the EPA, which compiles this information and makes it available to the EIA. 2019 is the most recent complete compilation currently available and can be obtained here. Effects on the environment and human health can be determined by the quantity of pollution released, and, in the cases of sulfur dioxide and nitrogen oxides, by location relative to human population and natural resources. However, as a measure of overall utility performance, it is most appropriate to consider emissions per unit of power generated. So, for example, while Texas's electricity sector produces the most emissions of all pollutants by a wide margin, its emissions intensity for all pollutants is around the median.

Table 11: 2019 Pollutant Emissions from the Electric Sector

Metric	2019 Value	2019 Rank
CO2 Emissions in Metric Tons	57,231,577	9
SO2 Emissions in Metric Tons	74,311	5
NOX Emissions in Metric Tons	51,283	6
CO2 Emission Intensity in Metric Tons	490	19
SO2 Emission Intensity in Metric Tons	0.64	9
NOX Emission Intensity in Metric Tons	0.44	16

Carbon Dioxide Emissions

As shown in Figure 89, Michigan ranked 19th worst among the states in carbon dioxide pollution per gigawatt-hour in 2019 with 530.4 metric tons emitted for every gigawatt-hour generated. This is worse than the median of all states and around the median of its six-state peer group, with Illinois and Minnesota performing better. Michigan's carbon dioxide emissions per gigawatt-hour have declined at a compound annual growth rate of roughly 3.3% from 2010-2019.

Figure 87 shows that Michigan's annual carbon dioxide emissions of **57,231,577** metric tons ranked 9th worst among the states in 2019. Michigan's compound annual growth rate of total carbon dioxide emissions was -2.9% from 2010-2019.

Figure 87: 2019 CO2 Emissions from the Electric Sector in Millions of Metric Tons

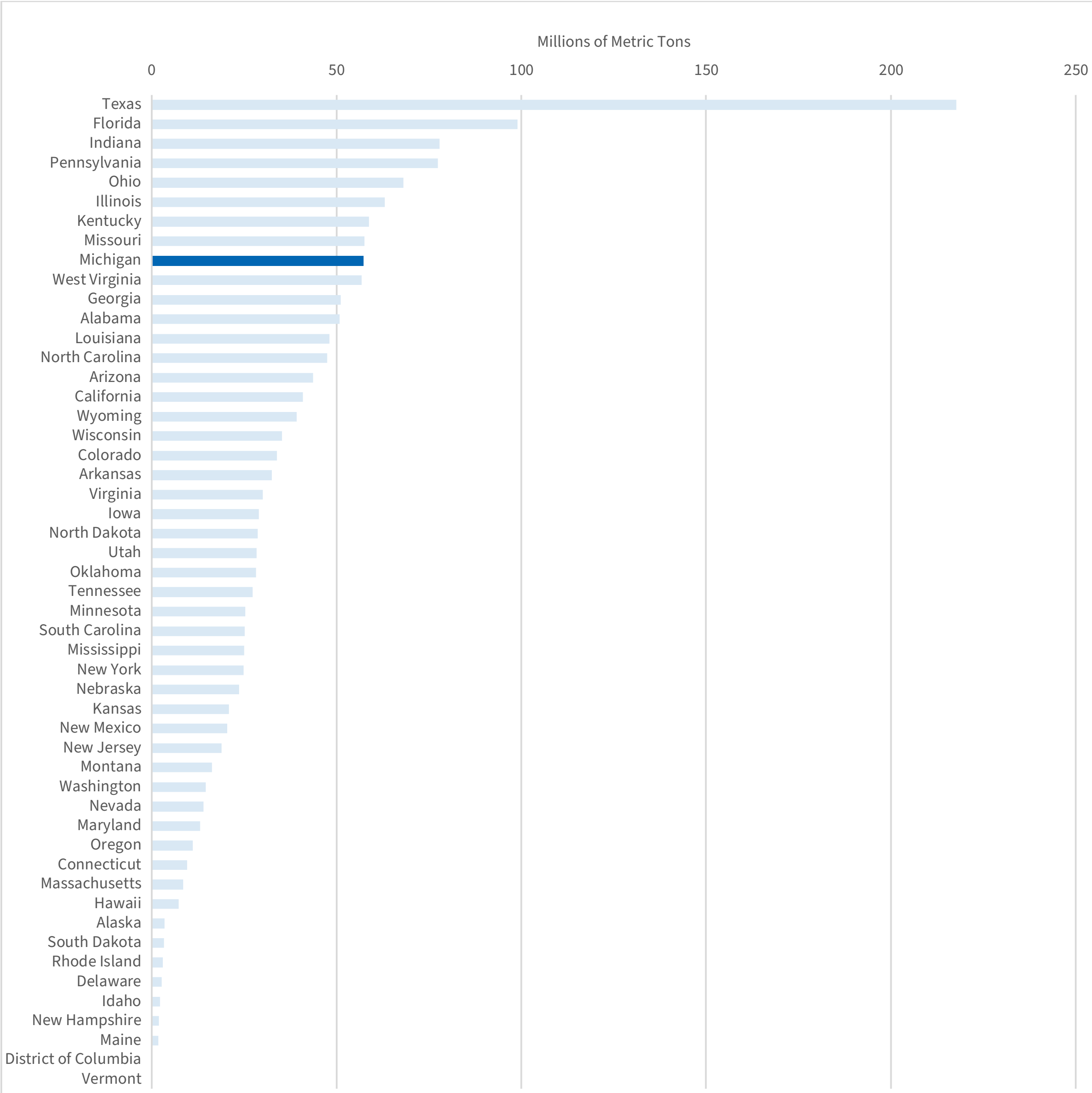


Figure 88: 2019 CO2 Emissions from the Electric Sector in Millions of Metric Tons

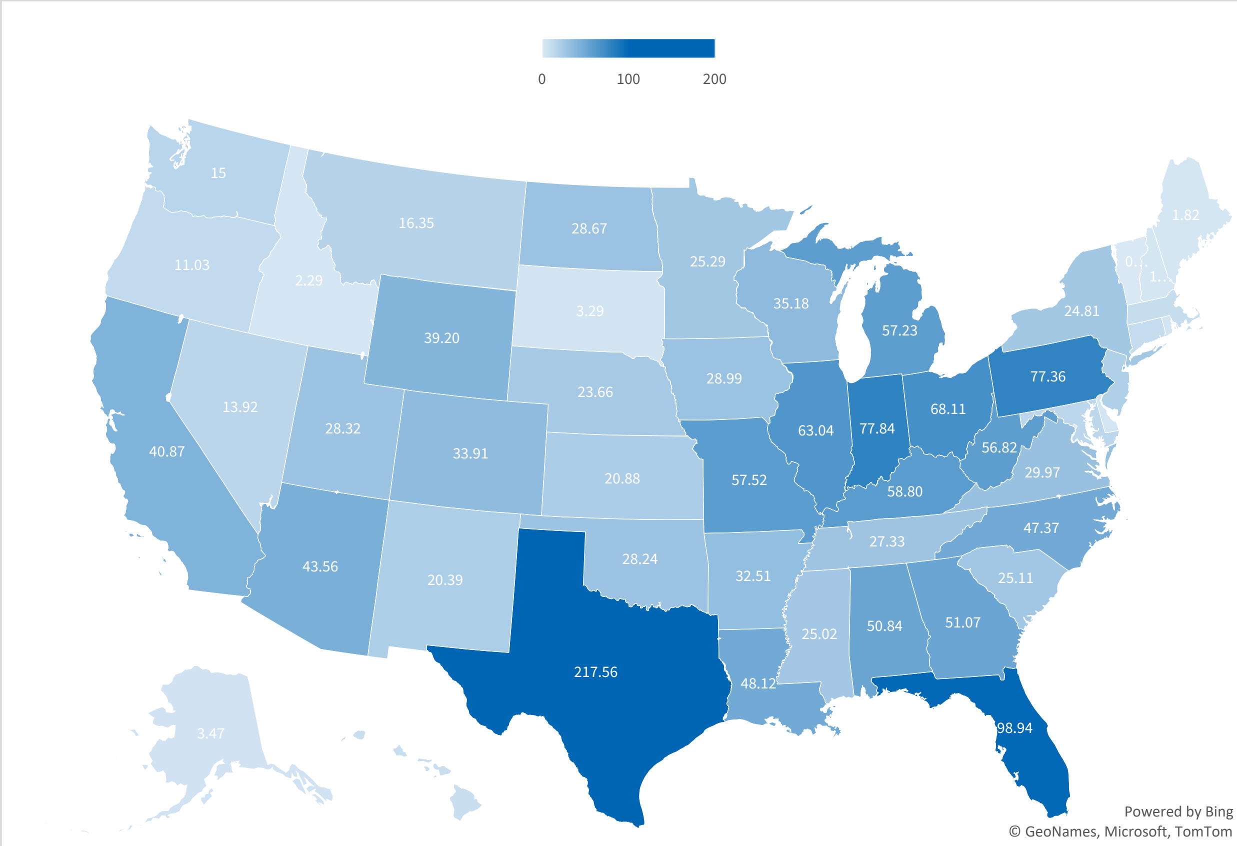


Figure 89: 2019 CO2 Intensity in Metric Tons per Gigawatt Hour of Generation

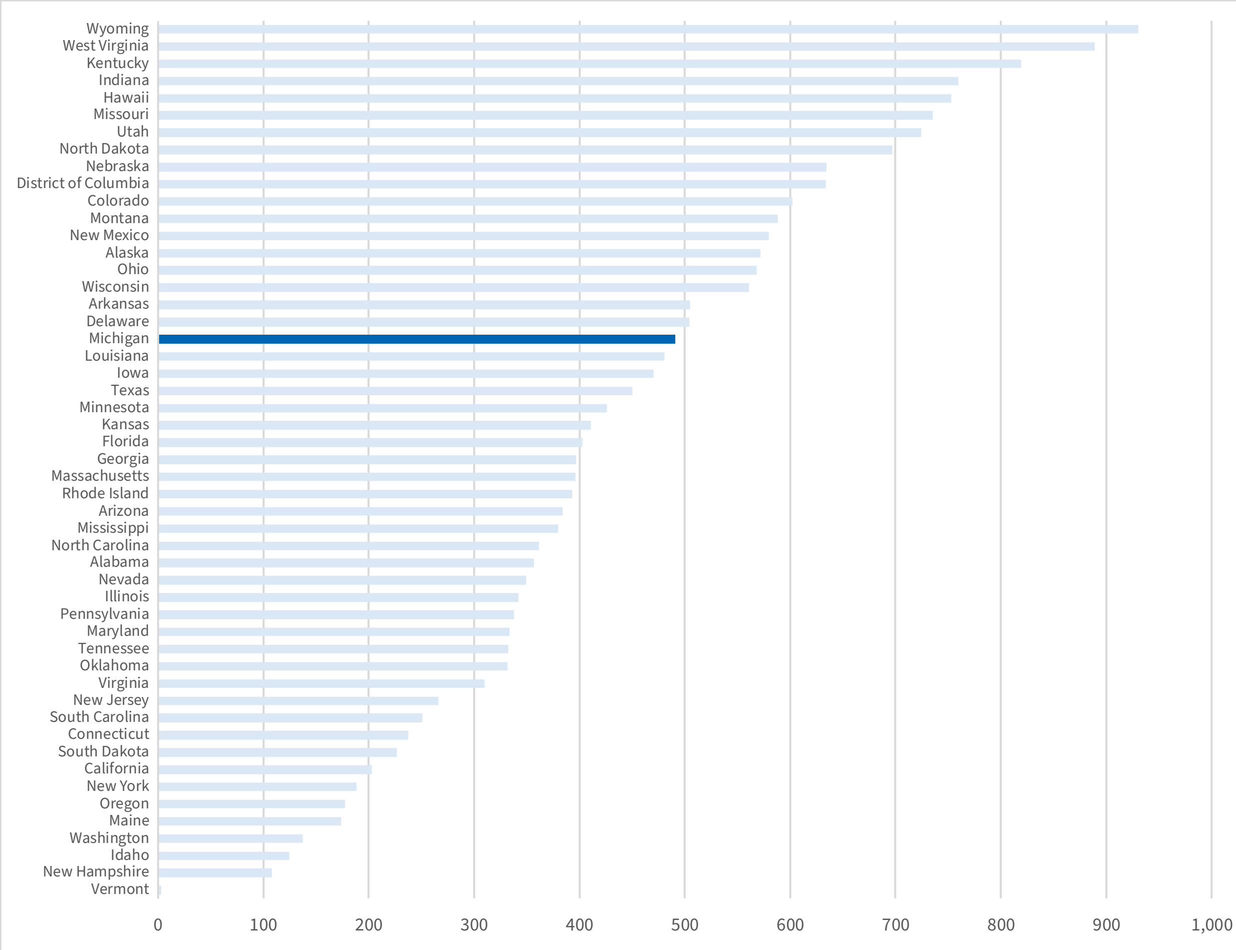
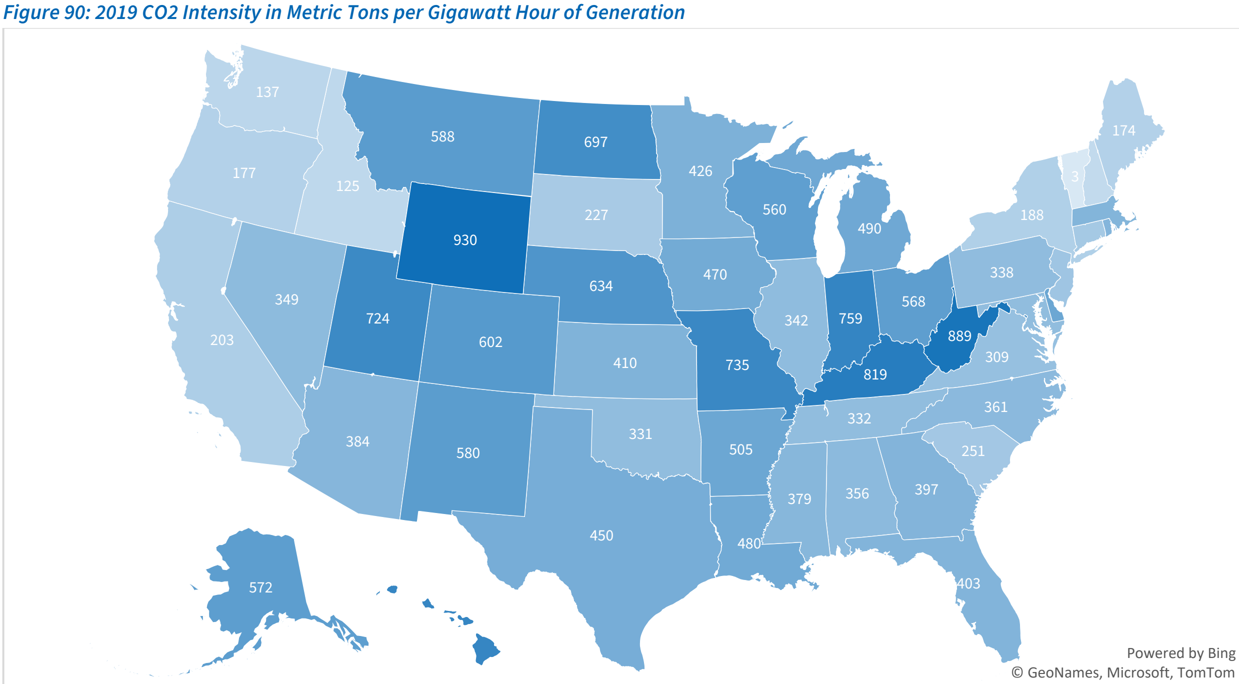


Figure 90: 2019 CO2 Intensity in Metric Tons per Gigawatt Hour of Generation



Sulfur Dioxide Emissions

As shown in **Figure 93**, Michigan ranked 9th worst among the states in sulfur dioxide pollution per gigawatt-hour in 2019, with 0.64 metric tons emitted for every gigawatt-hour generated. This emissions rate is significantly higher than in most states, with only Ohio performing worse among its peer group. Michigan's sulfur dioxide emissions per gigawatt-hour have significantly and steadily declined since 2010 at a compound annual rate of 13.2%. However, many states have experienced larger rates of decreases over that period.

Figure 91 shows that Michigan's 2019 sulfur dioxide emissions of 74,311 metric tons ranked 5th worst among the states, with only Illinois and Ohio emitting more sulfur dioxide among peer States. Michigan's rate of decline in total sulfur dioxide emissions has averaged 12.8% per year, but more than half of states had more rapid declines over the same time period.

Figure 91: 2019 SO2 Emissions from the Electric Sector in Metric Tons

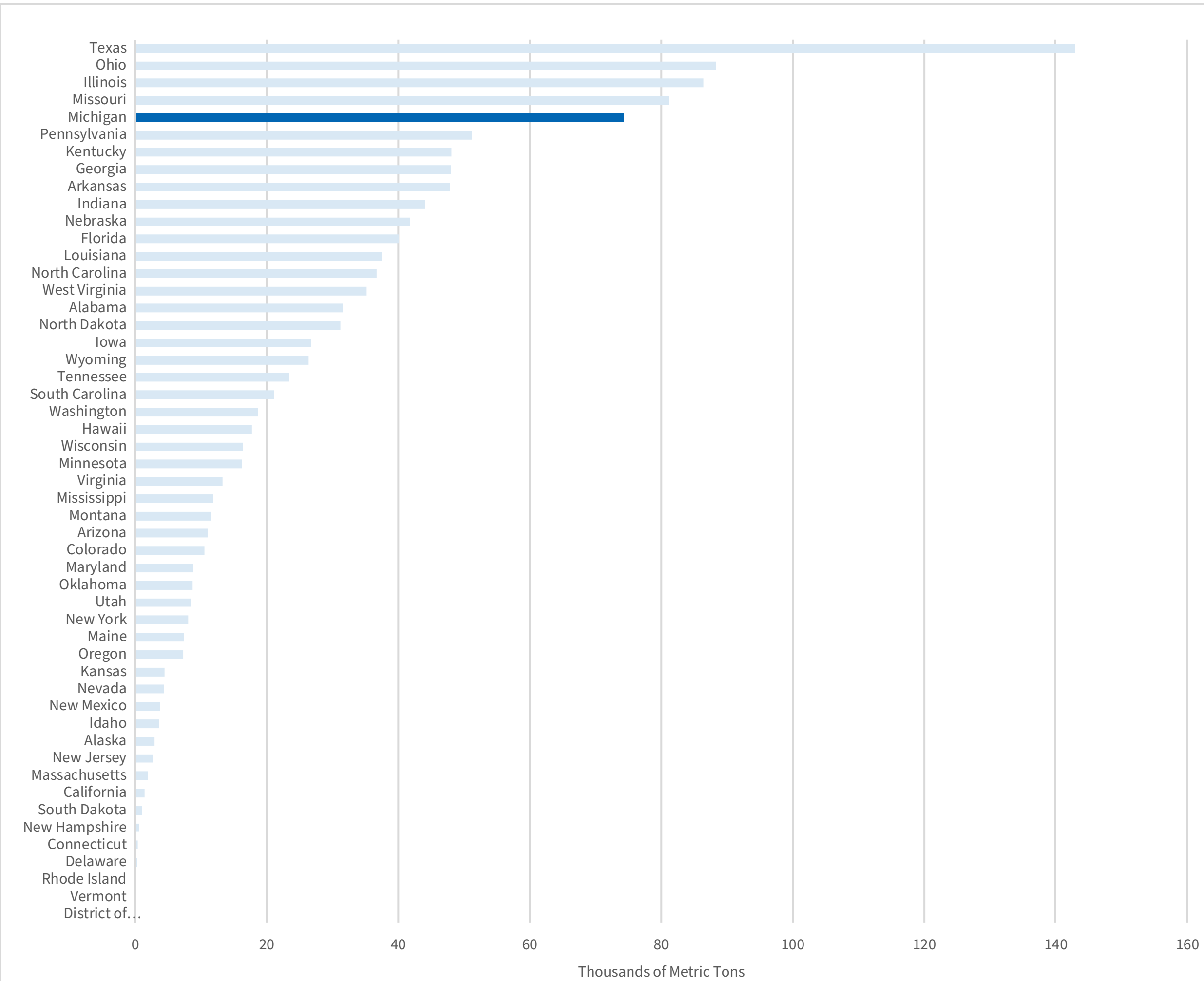


Figure 92: 2019 SO2 Emissions from the Electric Sector in Thousands of Metric Tons

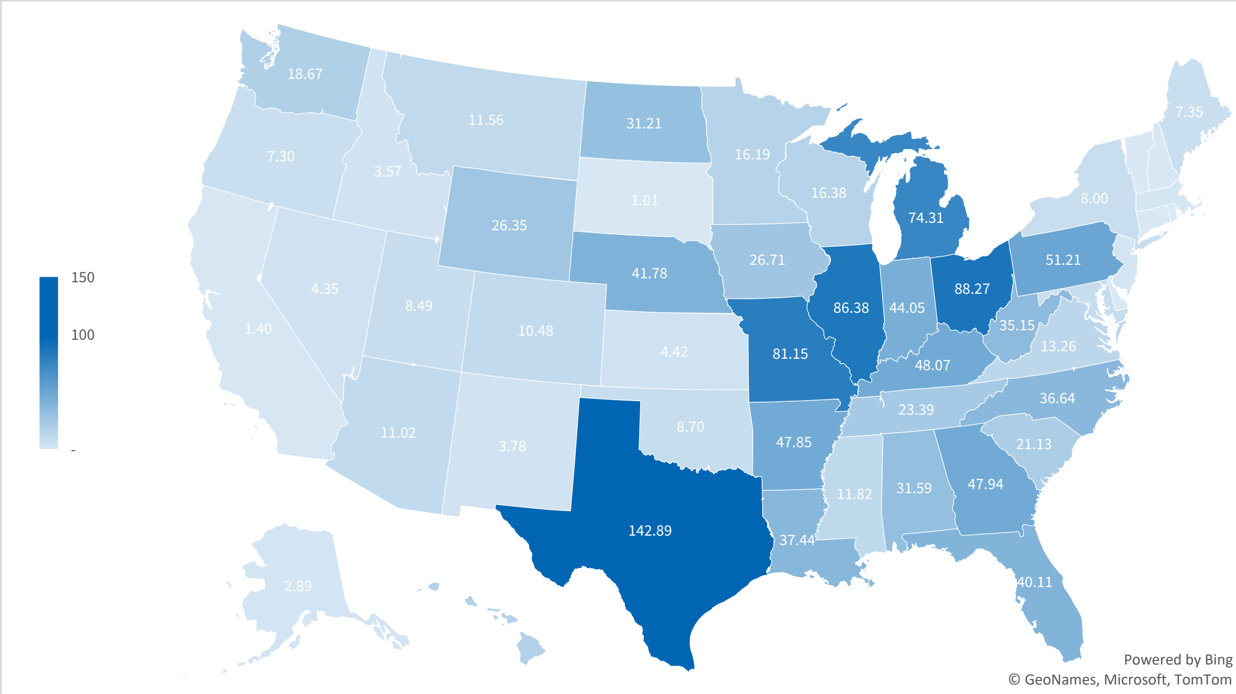


Figure 93: 2019 SO2 Intensity in Metric Tons per Gigawatt Hour of Generation

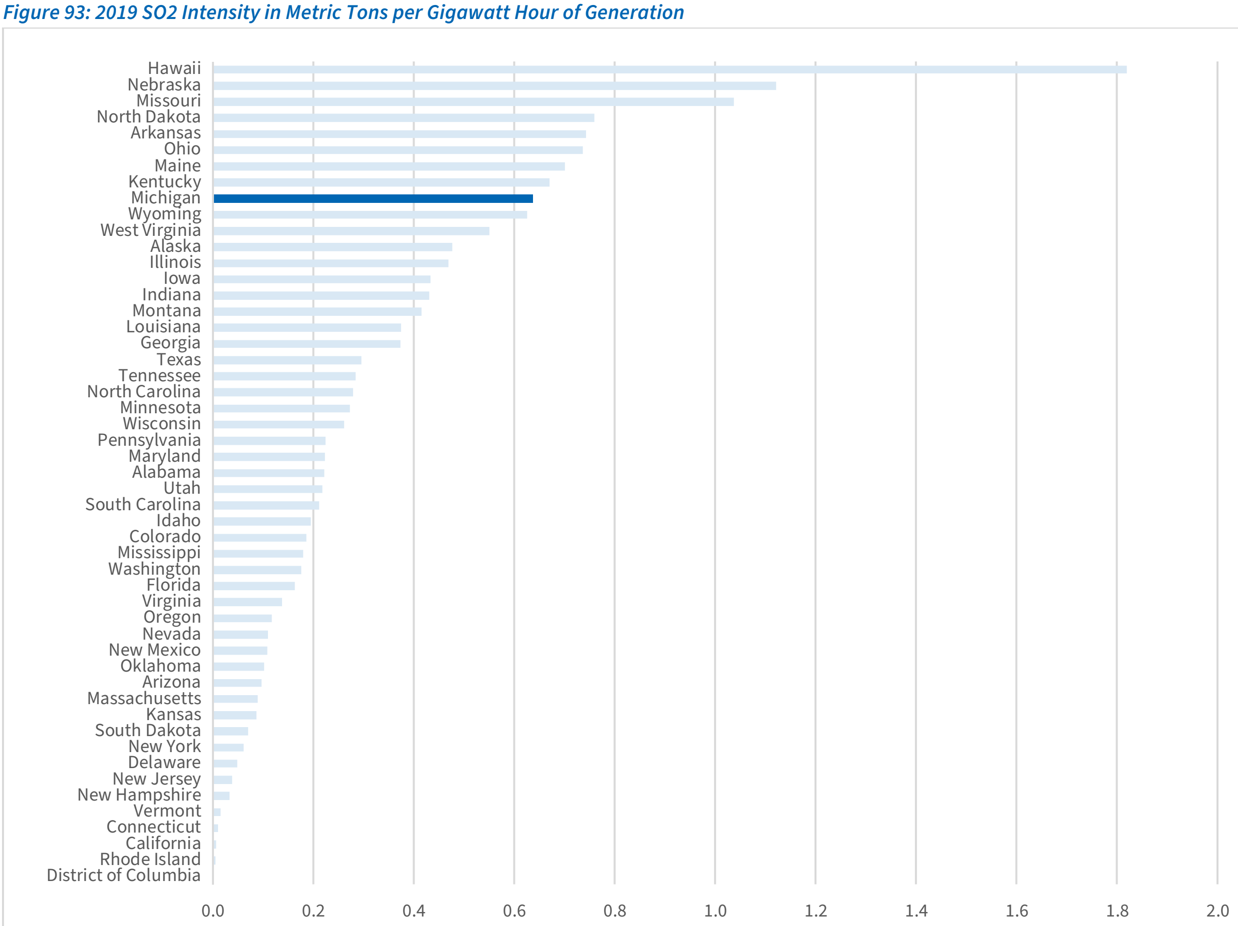
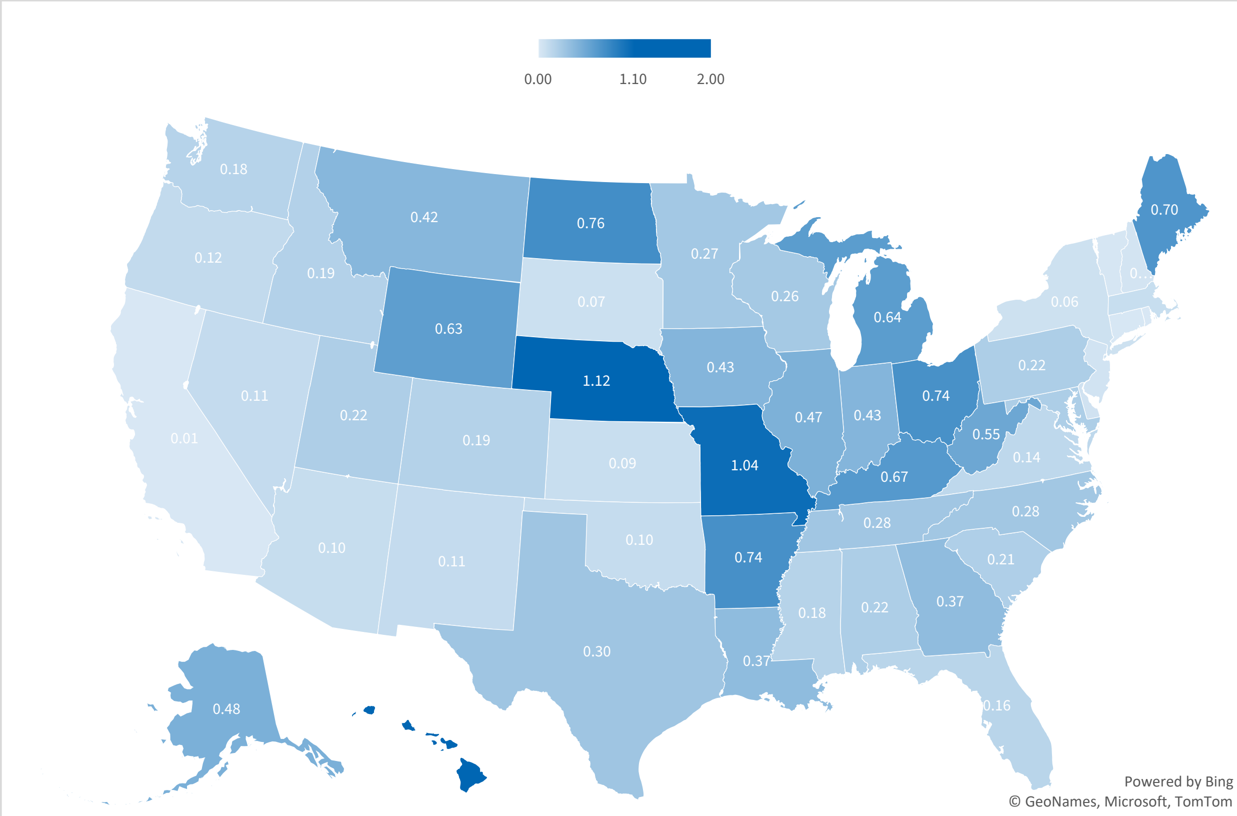


Figure 94: 2019 SO2 Intensity in Metric Tons Per Gigawatt Hour of Generation



Nitrogen Oxide Emissions

As shown in Figure 97, Michigan ranked 16th worst among the states in nitrogen oxides emitted per gigawatt-hour in 2019 with 0.44 metric tons emitted for every gigawatt-hour generated. Michigan performs worse than most of its peers, except for Ohio and Indiana. Michigan's compound annual growth rate of nitrogen oxides was -6.4%.

Michigan ranks 6th worst in total nitrogen oxide emissions in 2019 as shown in Figure 95. In 2019 Michigan's annual rate of decline in total nitrogen oxide emissions was 5.9%.

Figure 95: 2019 NOX Emissions from the Electric Sector in Metric Tons

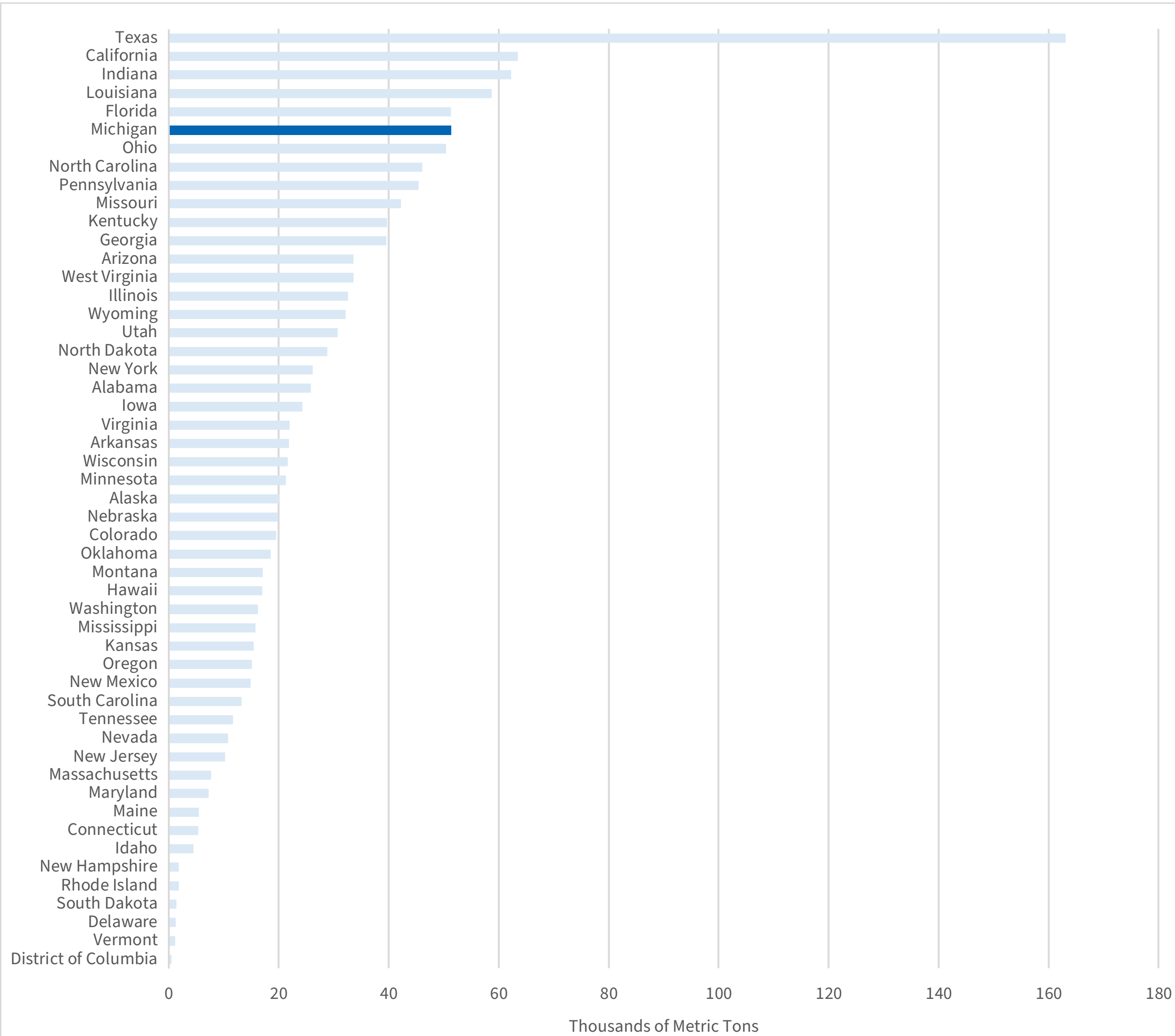


Figure 96: 2019 NOX Emissions from the Electric Sector in Thousands of Metric Tons

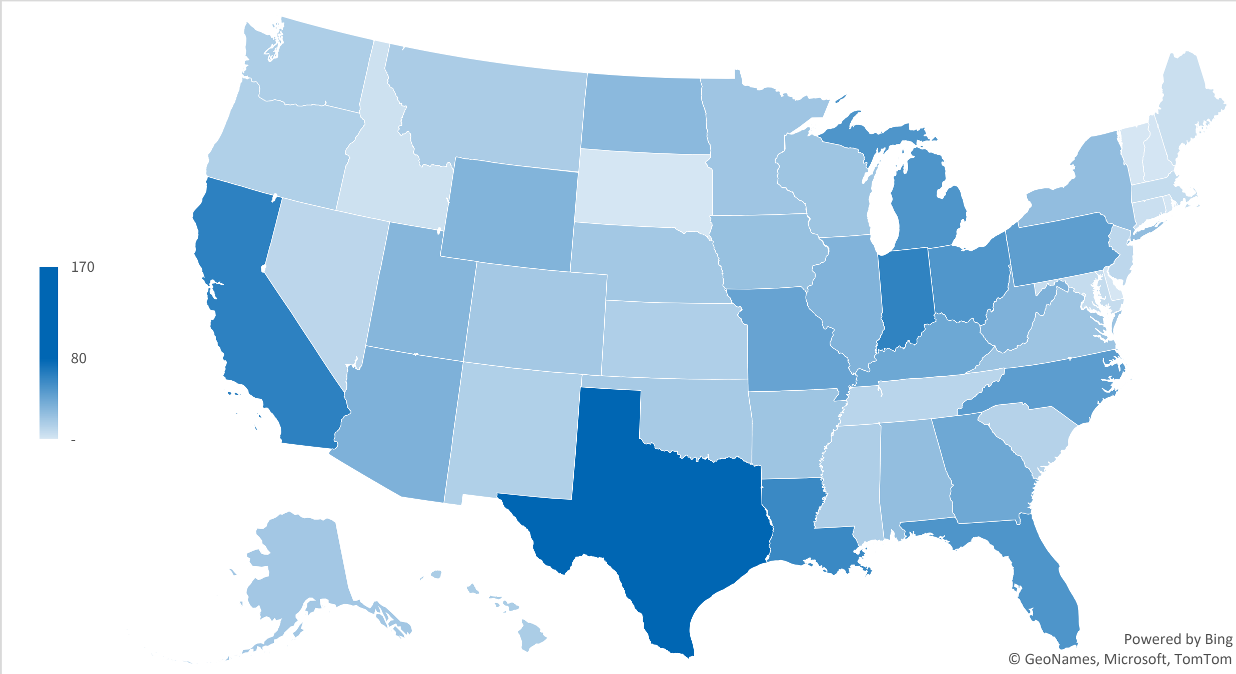


Figure 97: 2019 NOX Intensity in Metric Tons per Gigawatt Hour of Generation

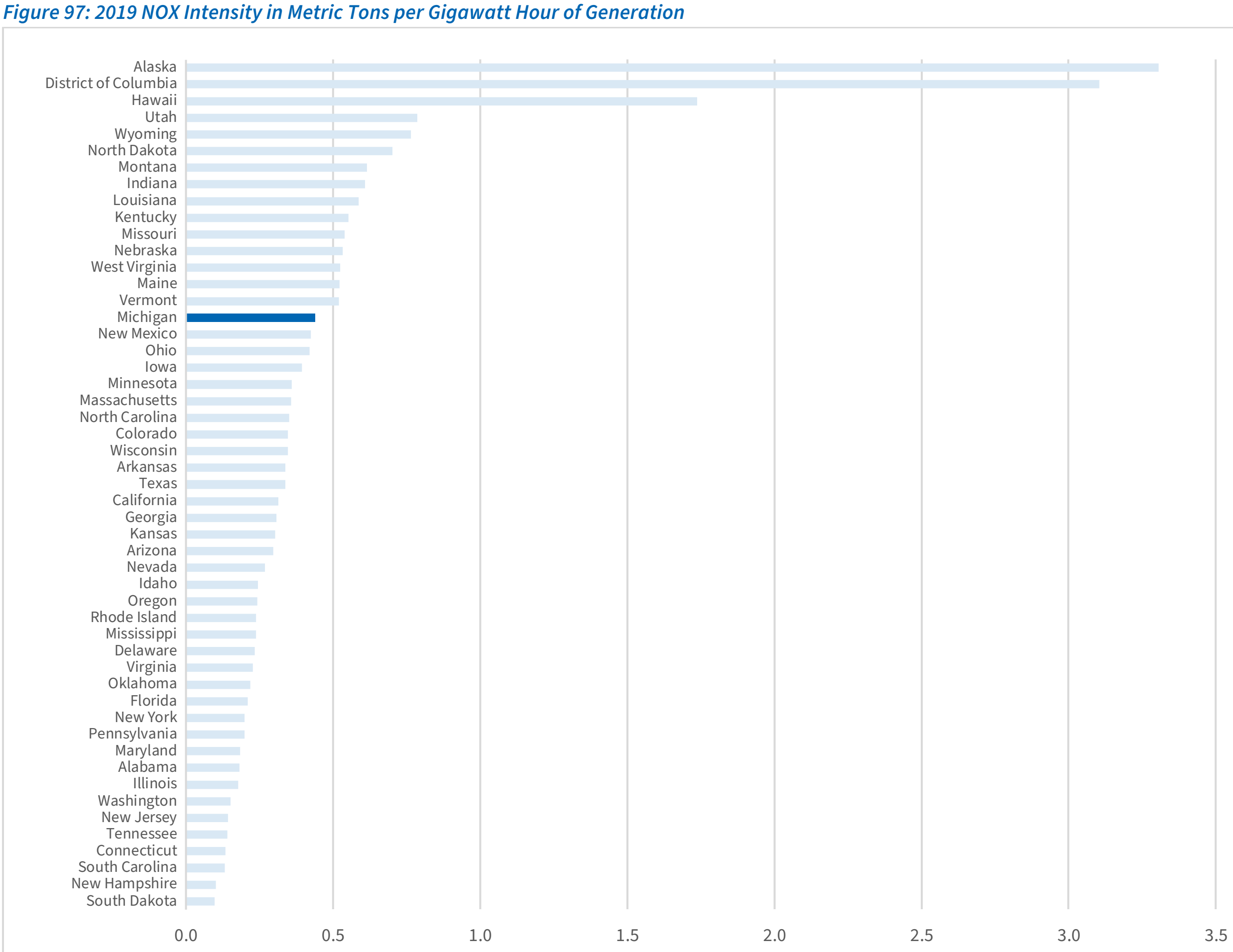
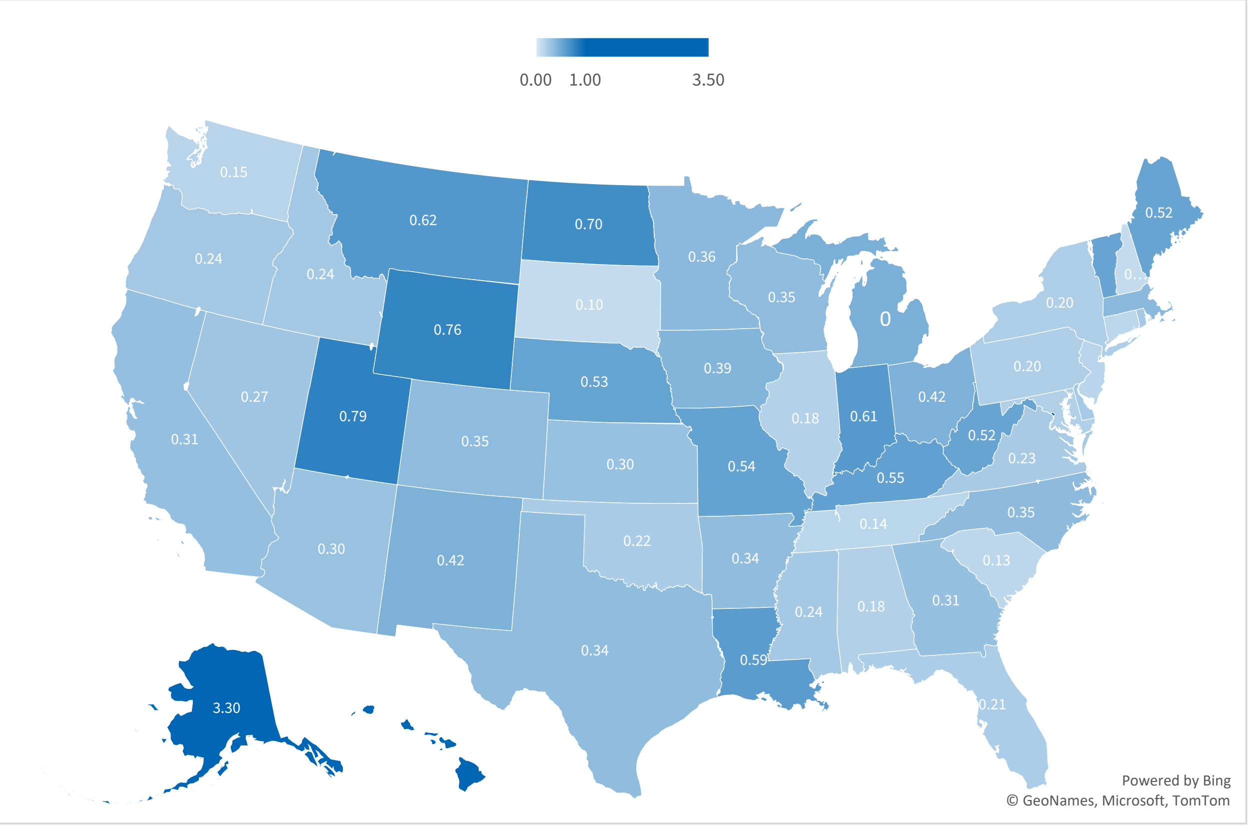


Figure 98: 2019 NOX Intensity in Metric Tons per Gigawatt Hour of Generation



Water Consumption and Withdrawals from Power Generation

Water is used in large quantities by the electricity sector, both for cooling and the production of steam to turn turbines in thermoelectric plants. The EIA's water data browser is still in its beta form, and has only recently been made available to the public.

Many thermoelectric plants require more water to run than they consume. When power plants use water for cooling, the water passes through the plant and is rereleased in the form of uncontaminated, but warmed, water, which can be harmful to aquatic ecosystems. Some power plants are designed to recycle and recondense steam, thus minimizing their total withdrawals, but increasing the proportion of water that is lost to steam. Because not all power plants use water with equal efficiency, as with emissions, water withdrawal and consumption intensity—gallons/MWh—is a useful way of understanding the relative water efficiency of different states' electric sectors. To best understand the different forms of water use by the electric sector, this report shows water use in four ways:

- Water Withdrawal—the volume of water pulled into power plants for cooling and steam production.
- Water Consumption—the volume of water that leaves power plants in the form of steam
- Water Withdrawal Intensity—the amount of water pulled into a power plant per MWh of electricity generation
- Water Consumption Intensity—the amount of water released as steam by a power plant per MWh of electricity generation

Table 12: 2019 Pollutant Emissions from the Electric Sector

Metric	2019 Value	2019 Rank
Water Withdrawals in Billions of Gallons	2,387	7
Water Consumption Billions of Gallons	52.3	7
Water Withdrawal Intensity in Thousands of Gallons per MWh	43,090	32
Water Consumption Intensity in Thousands of gallons per MWh	1,373	17

In total water withdrawals and consumption for electric production Michigan ranks as the 7th largest user, withdrawing 2,387 billions of gallons of water a year and consuming 52.3 billion gallons. This makes Michigan the 2nd largest user in its peer group, after Illinois, and the 3rd largest consumer after Illinois and Indiana (Figures 99 and 101).

In terms of efficiency of water use, Michigan withdraws 43 thousand gallons of water per MWh of electricity produced, making it the 32nd least efficient user. Michigan's withdrawal intensity is lower than its peer states' except for Minnesota. Michigan utilities' water consumption intensity is the 17th highest at 1,373 gallons of water consumed per MWh, making its consumption intensity lower than its peer states', except for Ohio (Figures 103 and 105).

Figure 99: 2019 Water Withdrawals from Electricity Generation in Billions of Gallons

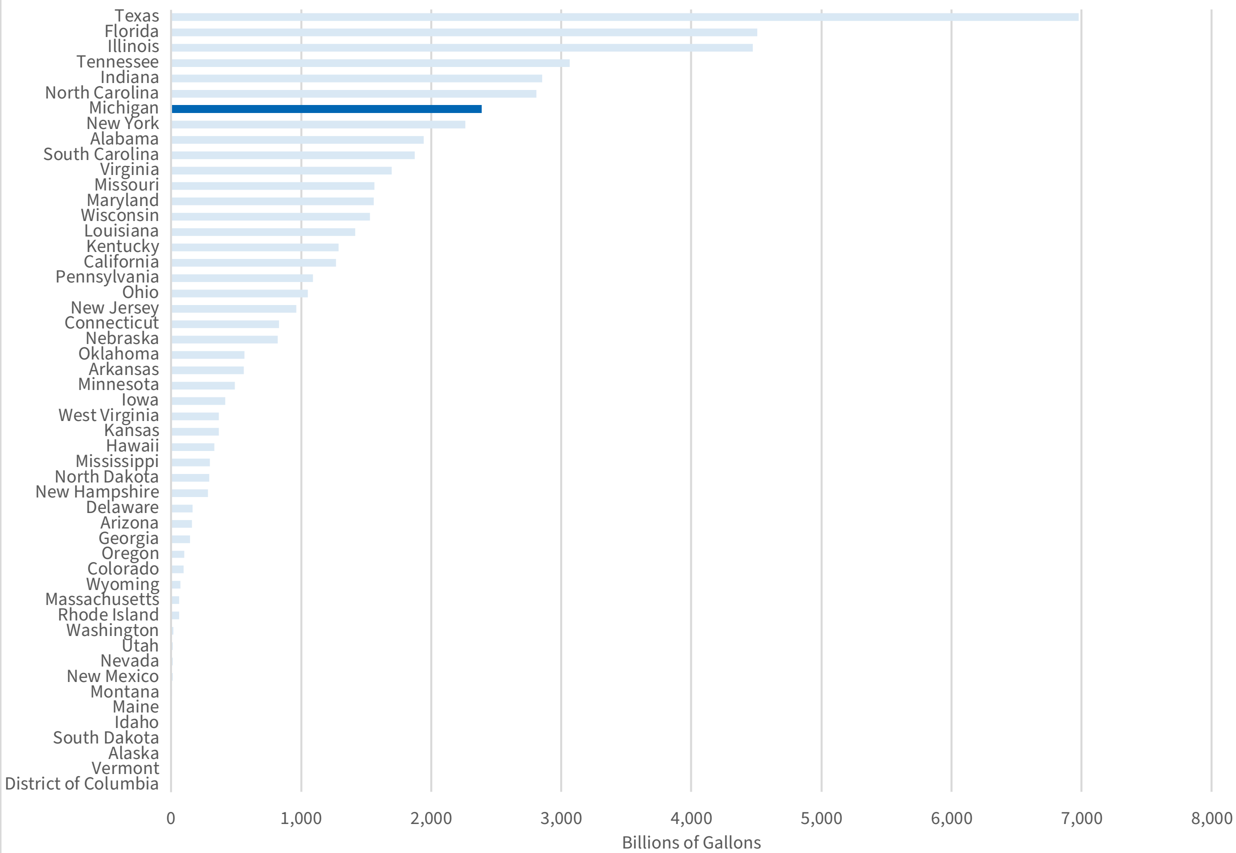


Figure 100: 2019 Water Withdrawals from Electricity Generation in Billions of Gallons

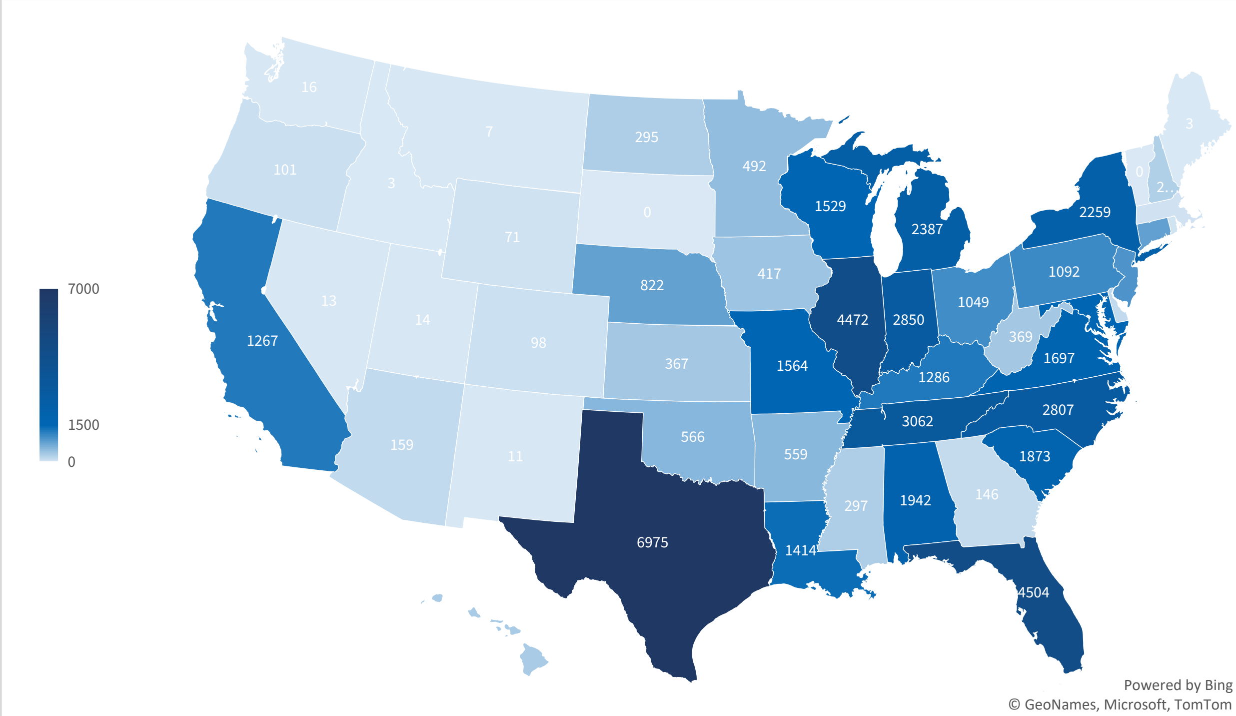


Figure 101: 2019 Water Consumption for Electricity Generation in Billions of Gallons

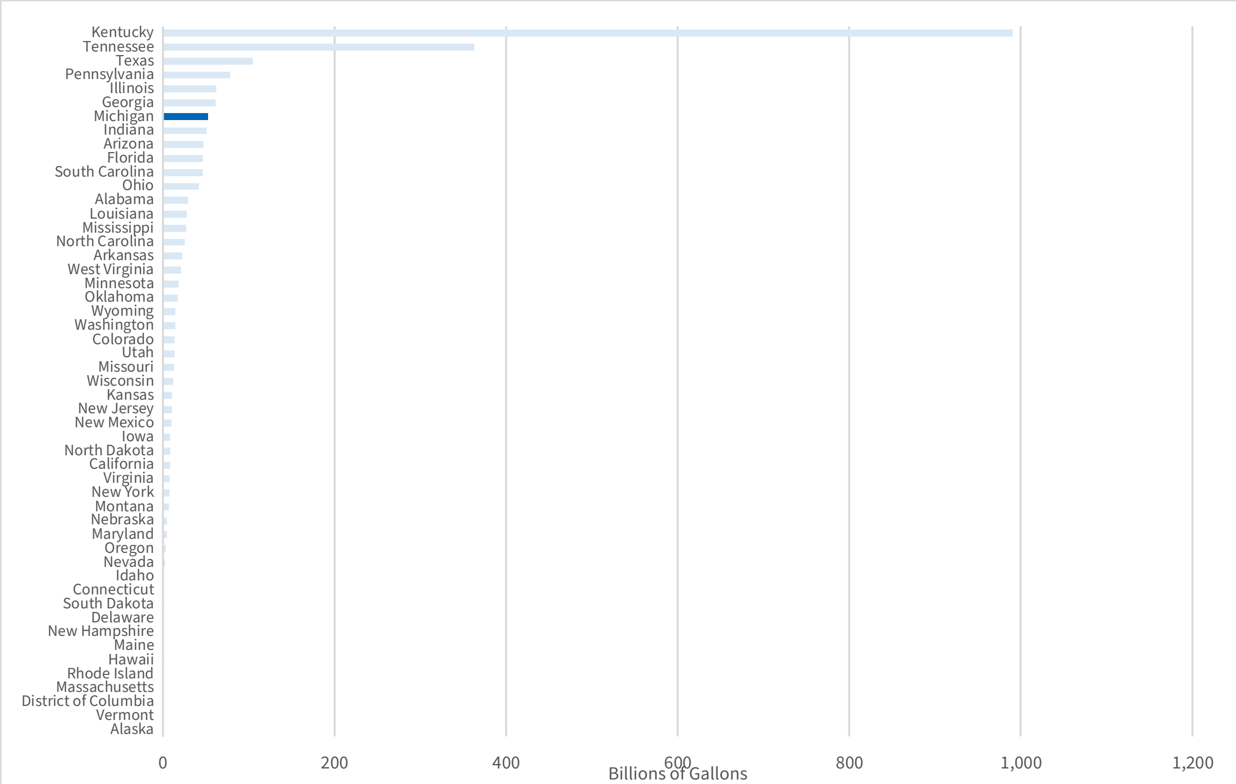


Figure 102: 2019 Water Consumption from Electricity Generation in Billions of Gallons

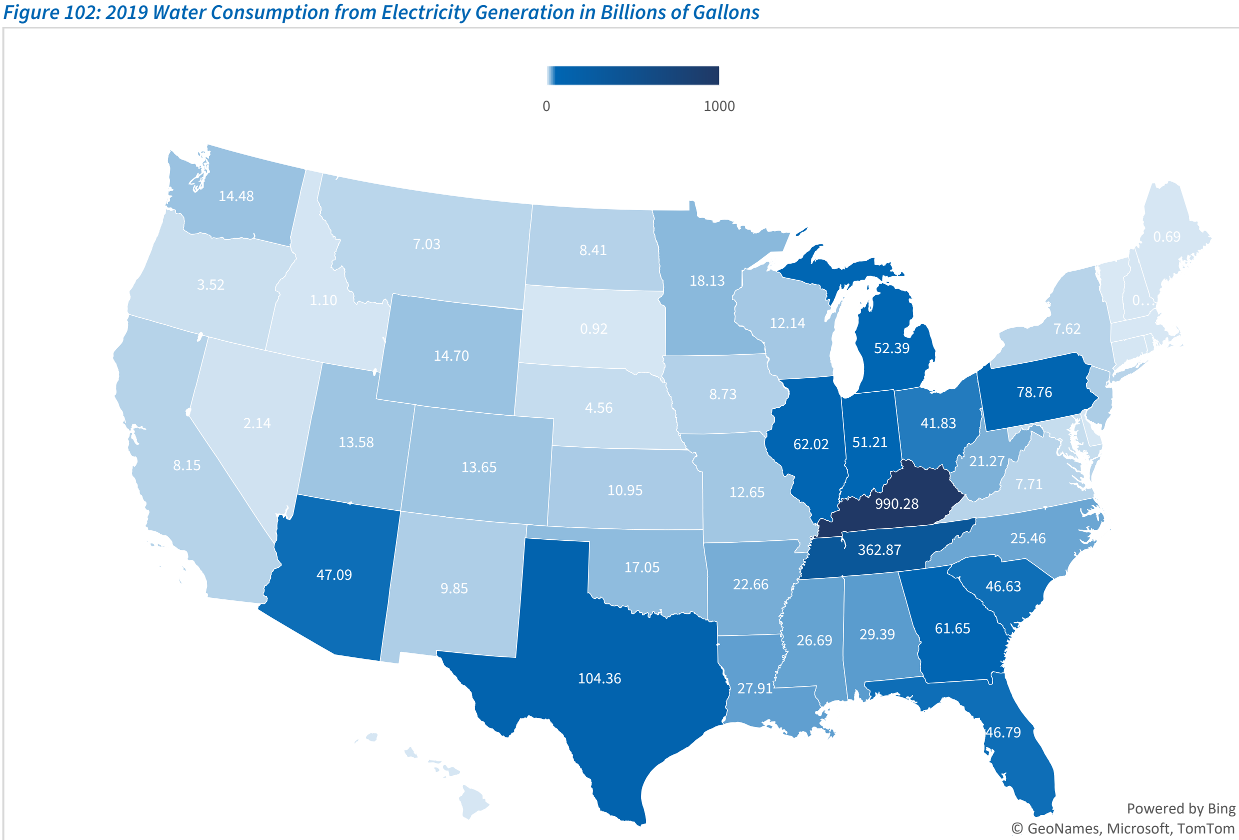


Figure 103: 2019 Water Withdrawal Intensity for Electricity Generation in Thousands of Gallons per Megawatt Hour

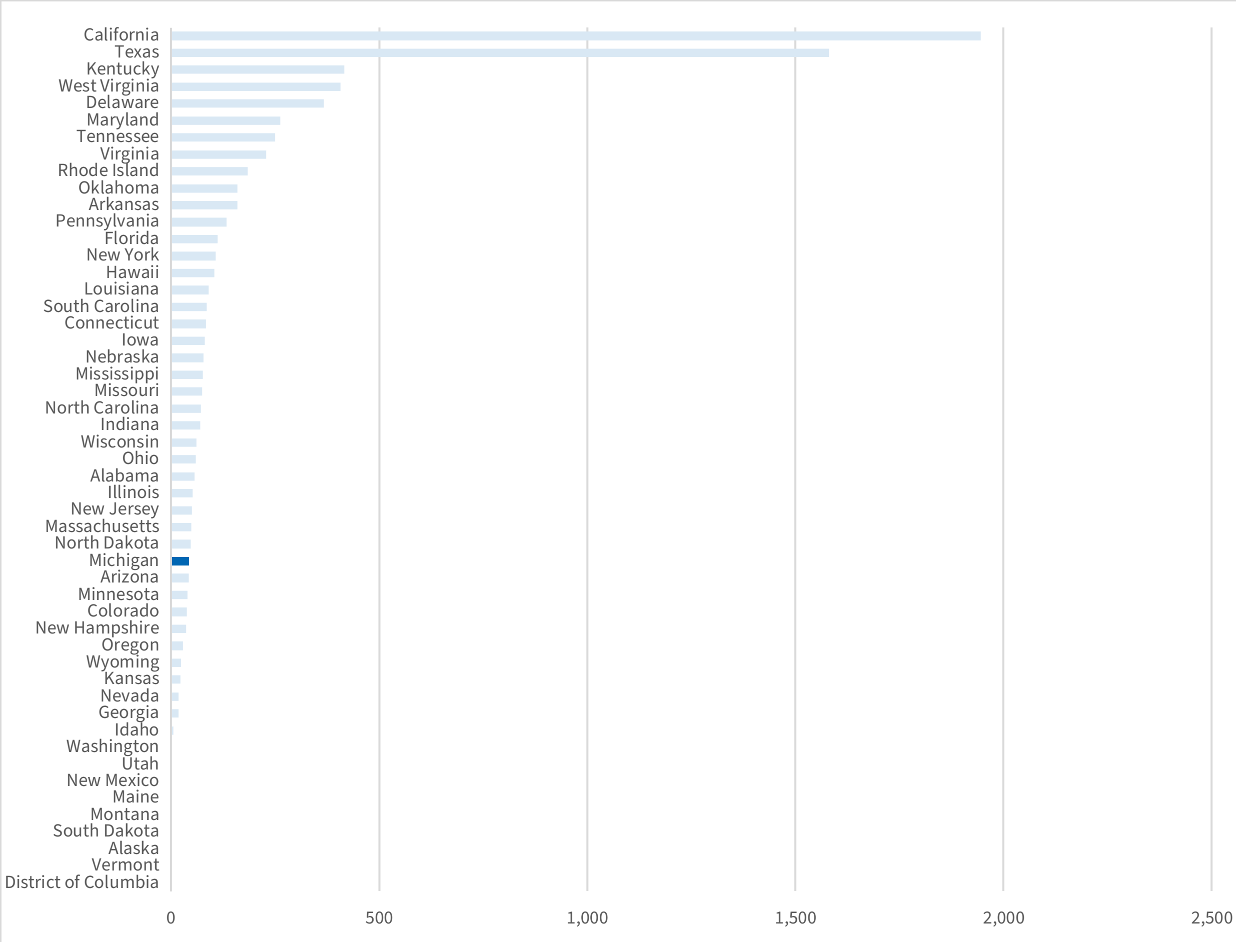


Figure 104: 2019 Water Withdrawal Intensity for Electricity Generation in Thousands of Gallons per Megawatt Hour

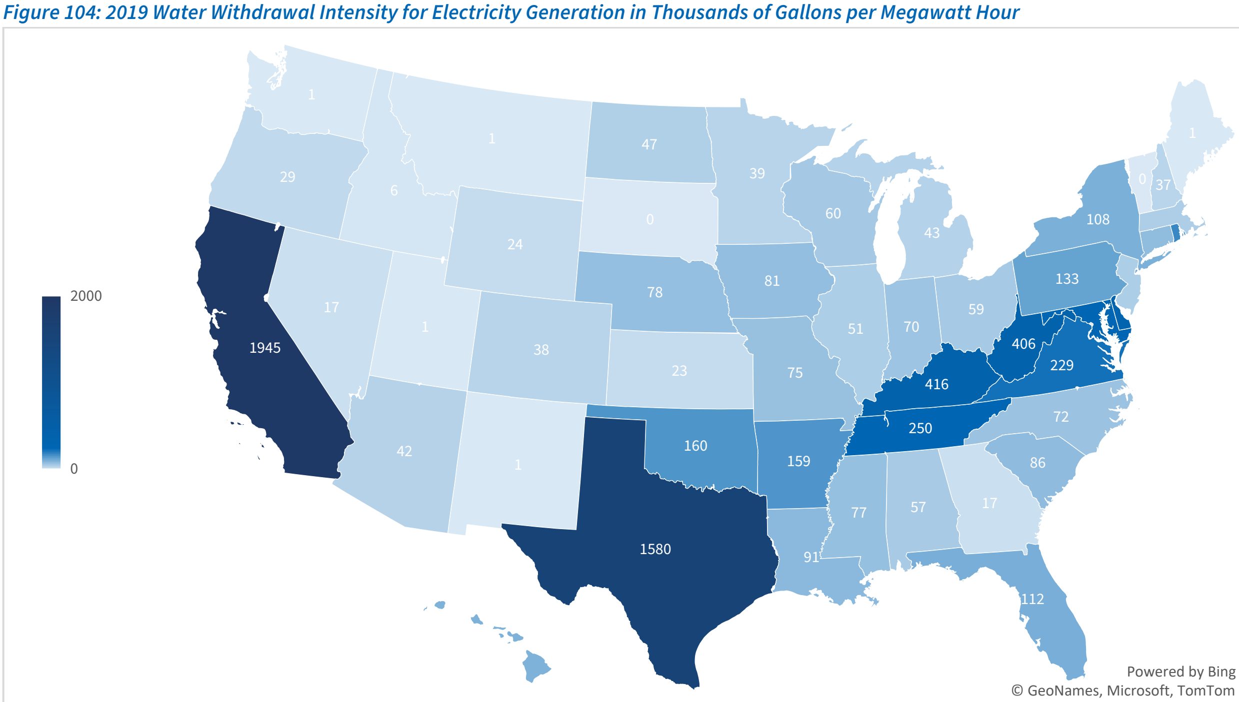


Figure 105: 2019 Water Consumption Intensity for Electricity Generation in Thousands of Gallons per Megawatt Hour

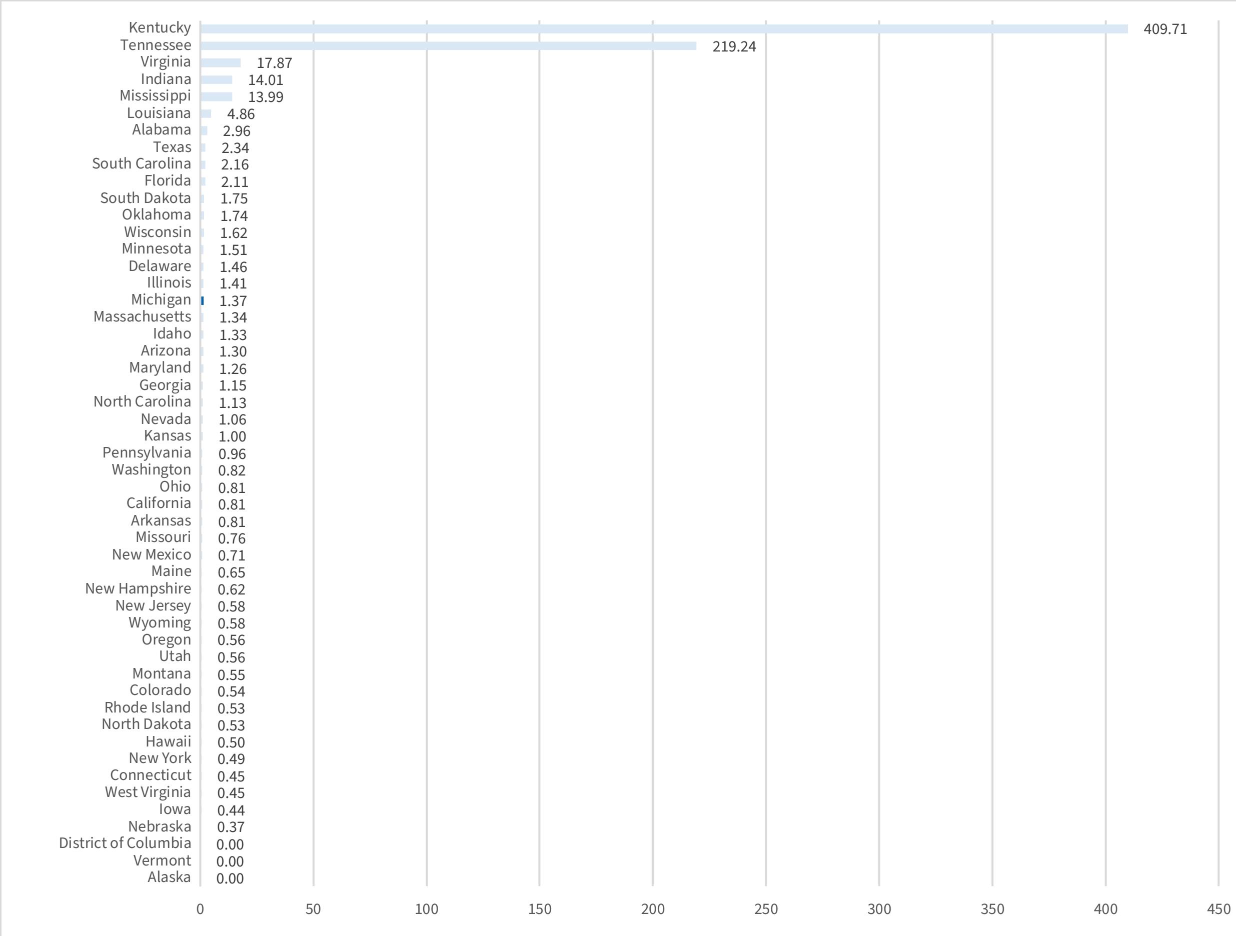
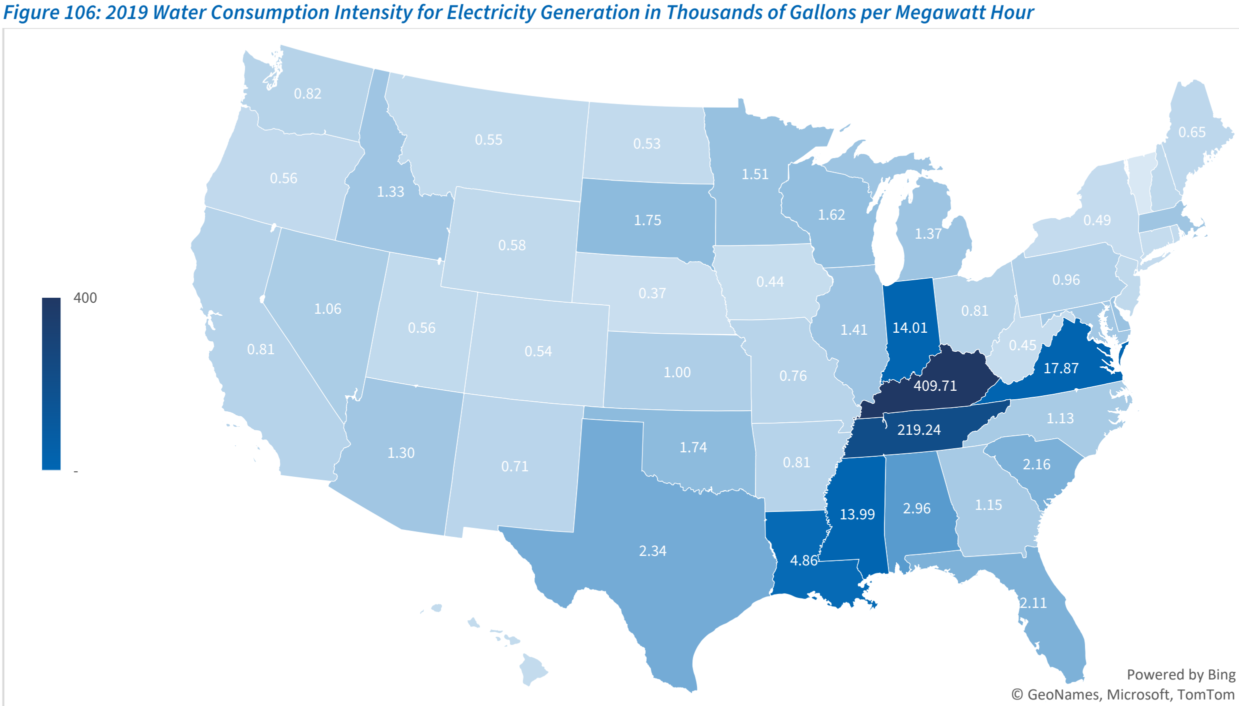


Figure 106: 2019 Water Consumption Intensity for Electricity Generation in Thousands of Gallons per Megawatt Hour



NATURAL GAS EMISSIONS

Overview

Natural gas, known also as methane, creates emissions when burned, but is itself also a potent greenhouse gas. This section looks to fill in a gap on the potential damages done to the environment from the natural gas sector. Emissions from the burning of natural gas for electricity production are reported in *Emissions from Electricity Generation* above. This section addresses the warming potential of natural gas losses by gas utilities, as reported by volume in *Gas Utility Performance,* as well as the warming potential of natural gas burned by sectors outside of the electric sector. The residential and commercial sectors burn natural gas for space and water heating, and the industrial sector burns natural gas for many other heat uses necessary for manufacturing.

Table 13: 2019 Pollutant Emissions from the Electric Sector

Metric	2019 Value	2019 Rank
CO2 Equivalent Emissions from Lost Natural Gas in Metric Tons	3,768,351	5
CO2 Emissions from Natural Gas Site Use in Metric Tons	39,271,015	8
SO2 Emissions from Natural Gas Site Use in Metric Tons	196	8
NOX Emissions from Natural Gas Site Use in Metric Tons	40,046	9

Natural Gas Losses as CO_2 Equivalents

Emissions from natural gas losses are reported as CO_2 equivalents by taking natural gas loss volume, the same volume as reported above in *Gas Utility Performance,* converting it to metric tons. and multiplying it by the lifetime CO_2 equivalency factor for methane. The final formula for converting methane to CO_2 equivalents is thus: *Metric Tons of CO_2 Equivalents = Losses in CF*Weight per CF methane (.035lb) * CO_2 Equivalency Factor (25)/lbs. per Metric Ton (2204.6 lbs).*

Michigan's CO_2 equivalents from lost natural gas are the 5th largest in the nation at 3.77 million metric tons, which is higher than all of its peer states except Illinois. Looking at Figure 23 in *Gas Utility Performance,* if we assume that a substantial portion of Consumers' Energy's unaccounted for natural gas is, in fact, leaked natural gas, the numbers in this section may not fully account for the harms of Michigan's lost natural gas.

Emissions from Gas Combustion Outside the Electric Sector

Burning natural gas produces multiple emission types including the CO_2, SO_2, and NO_x. There are consistent emissions factors for CO_2, and SO_2 from the burning of natural gas, but the NO_x emission factor from burning natural gas depends on the conditions under which it is burned. There is generally a higher NO_x emission factor when burning larger volumes of natural gas at higher temperatures. To compensate for this differential, the reported NO_x emissions use one factor—100lb/million CF natural gas—for residential and commercial uses, and a higher factor—190lb/million CF natural gas— for industrial uses.

Unfortunately, this provides only a rough approximation of the real NO_x emissions produced by these sectors.

The natural gas consumption data used for this subsection come from the [SEDS] database, while the emissions factors come from the [EPA.]

In Michigan, just under half of non-electric sector natural gas consumption—and therefore emissions—comes from the residential sector, with the commercial and industrial sectors contributing nearly equal amounts of the other half. Michigan is the 8th largest producer of emissions from natural gas use in terms of CO_2 and SO_2 with emissions of 39 million and 196 metric tons respectively (**Figures 109 and 111**). Michigan is the 9th largest emitter of NO_x from site use of natural gas in the country, with these emissions being approximately 40,000 metric tons (**Figure 113**). In relation to its peer states, Michigan is near the middle, producing fewer CO_2 and SO_2 emissions than Ohio and Illinois, and fewer NO_x emissions than Ohio, Illinois and Indiana (**Figure 114**).

Figure 107: 2019 CO2 Equivalents from Lost Natural Gas in Thousands of Metric Tons

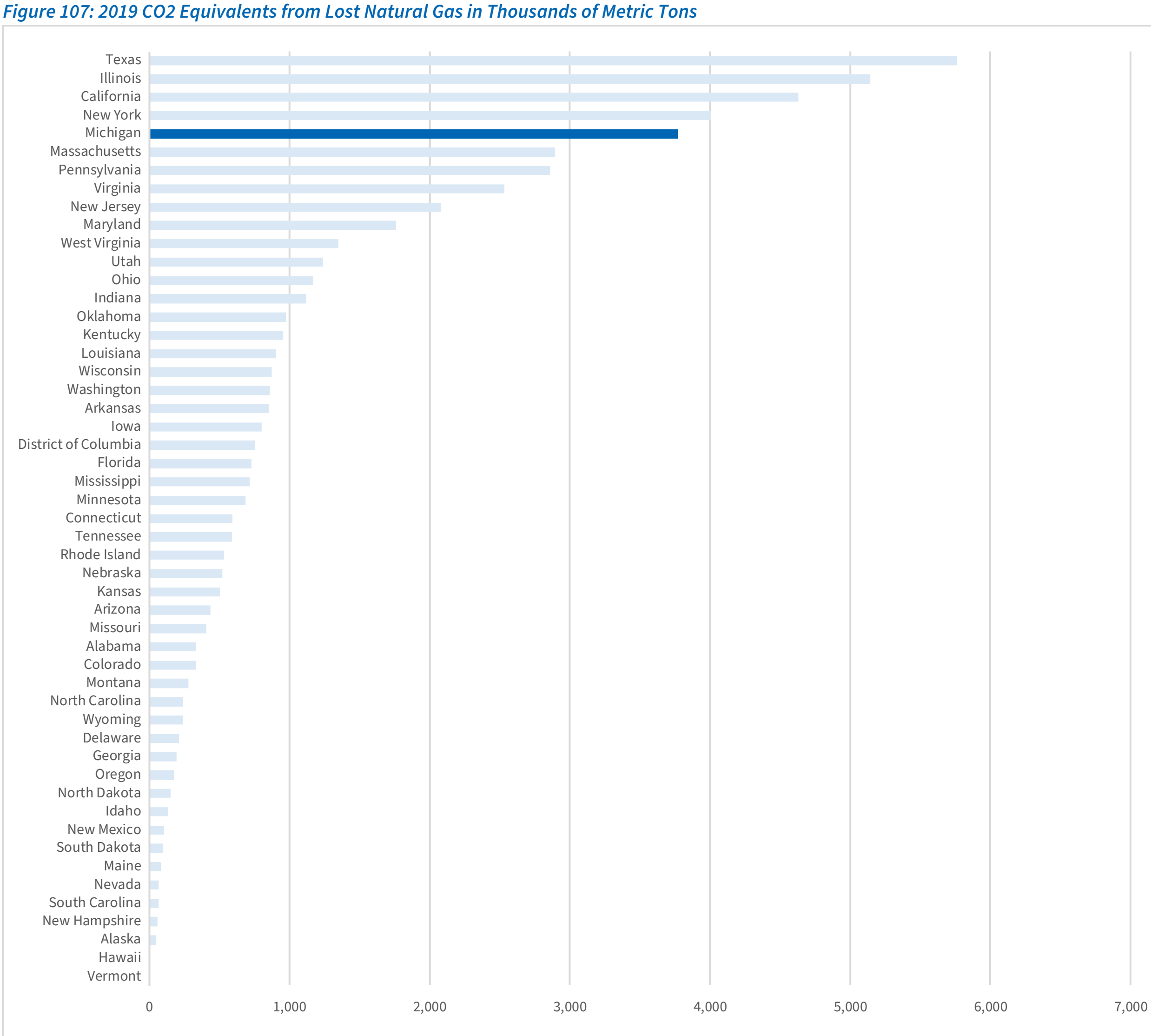


Figure 108: 2019 CO2 Equivalents from Lost Natural Gas in Thousands of Metric Tons

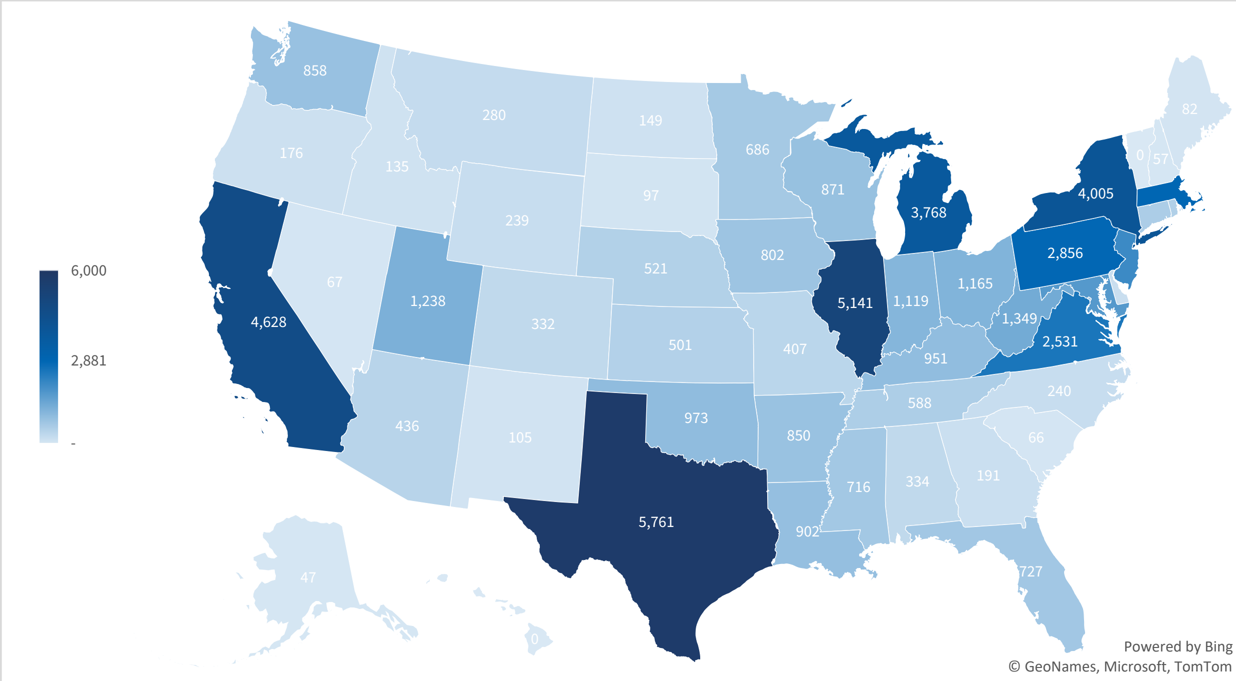


Figure 109: 2019 CO2 Emissions from Natural Gas Combustion in All Sectors (Except Electric) in Millions of Metric Tons

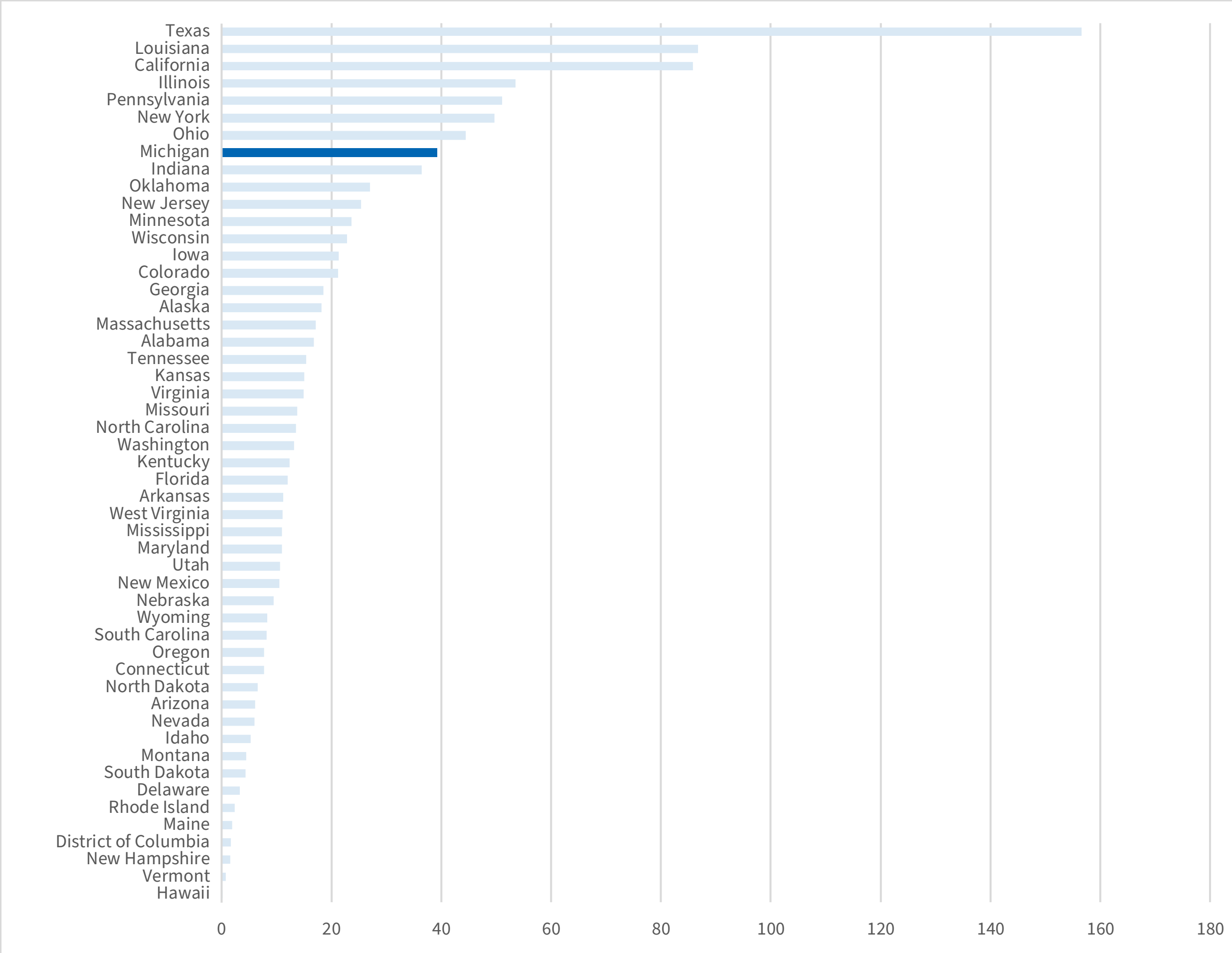


Figure 110: 2019 CO2 Emissions from Natural Gas Combustion in All Sectors (Except Electric) in Millions of Metric Tons

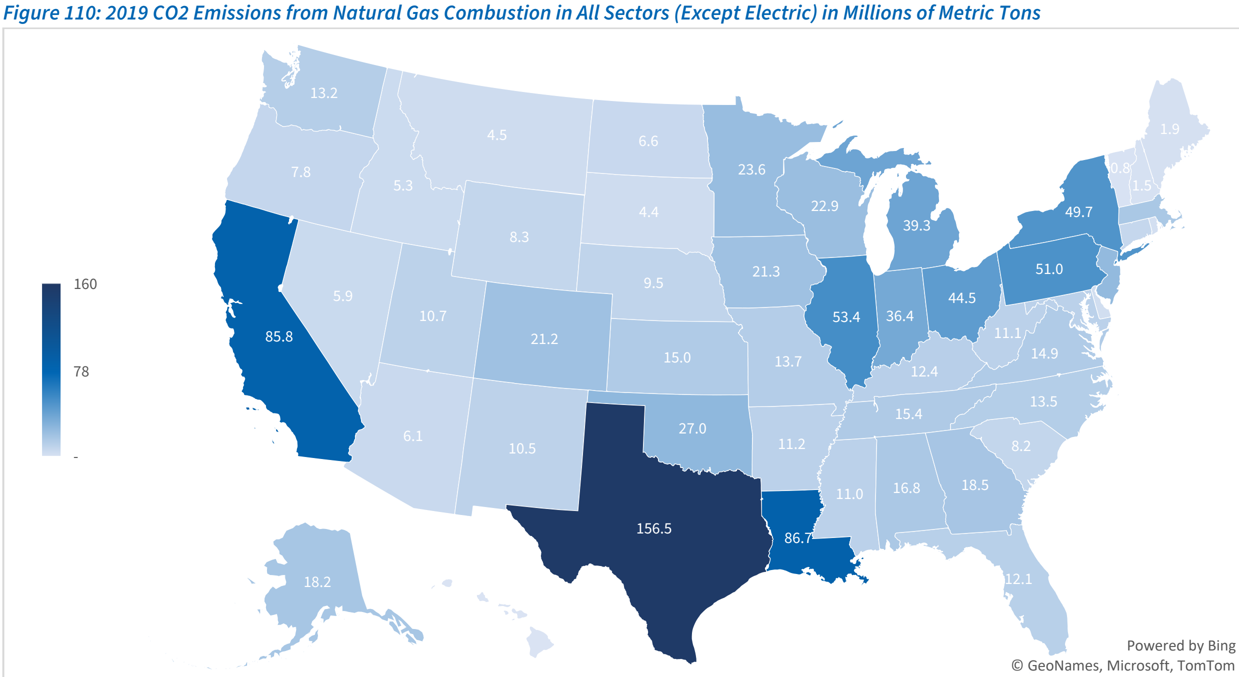


Figure 111: 2019 SO2 Emissions from Natural Gas Combustion in All Sectors (Except Electric) in Millions of Metric Tons

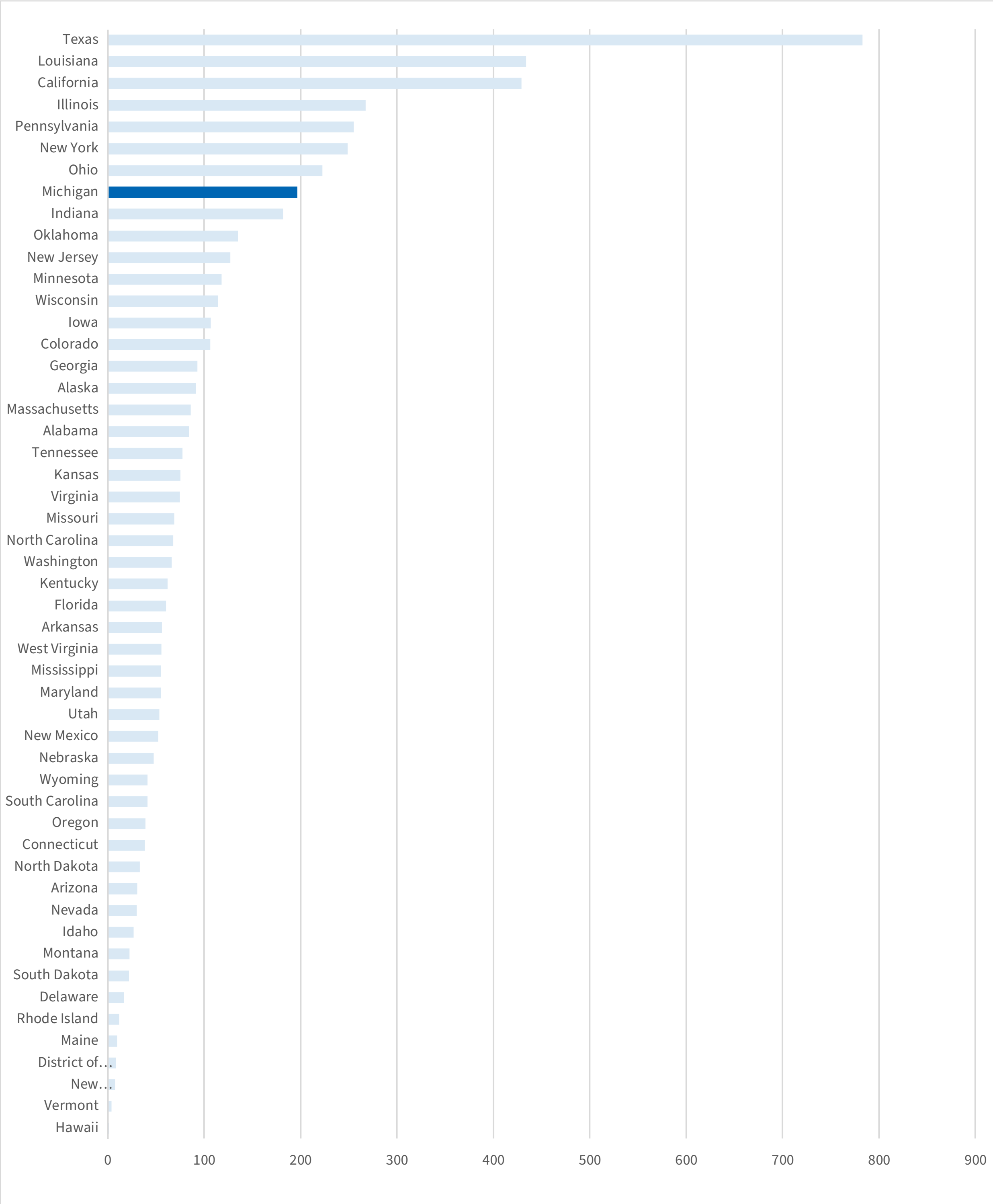


Figure 112: 2019 SO2 Emissions from Natural Gas Combustion in All Sectors (Except Electric) in Millions of Metric Tons

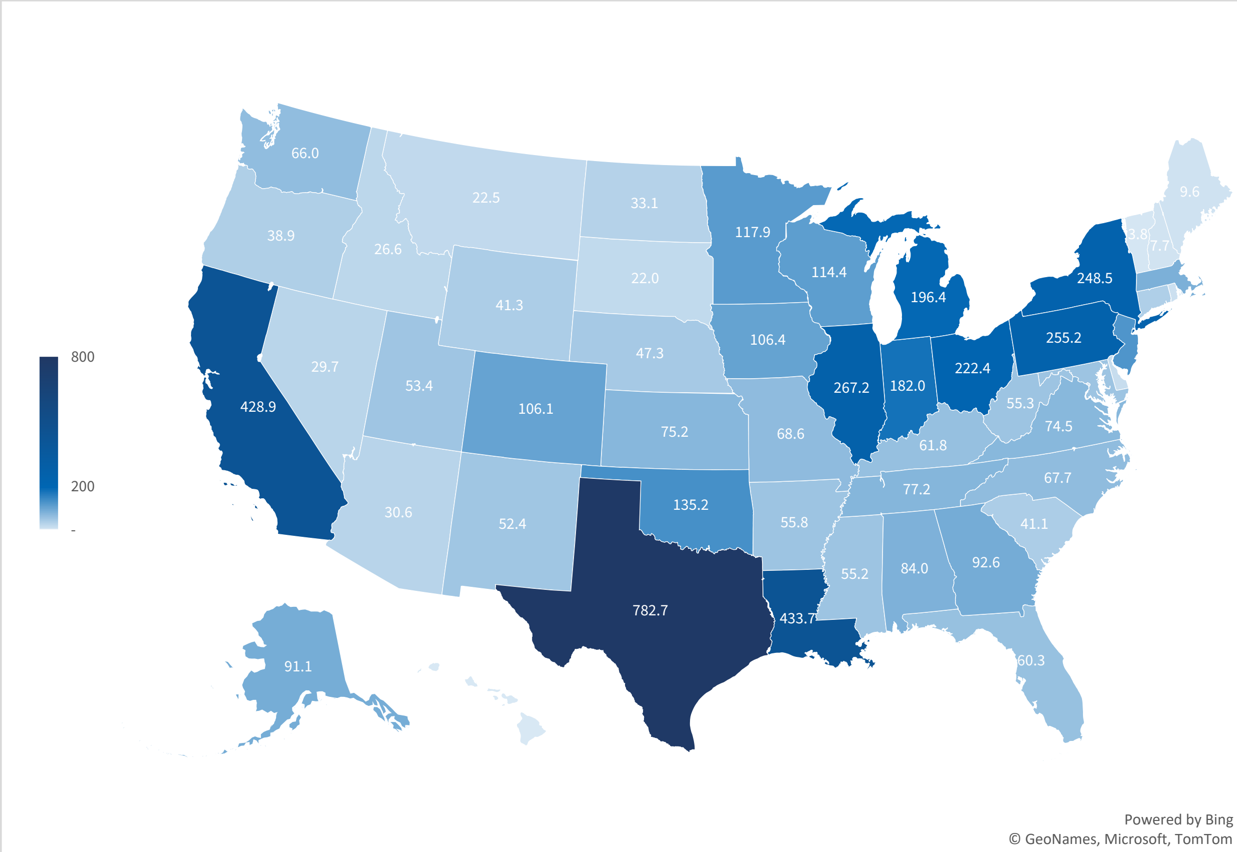


Figure 113: 2019 NOX Emissions from Natural Gas Combustion in All Sectors (Except Electric) in Thousands of Metric Tons

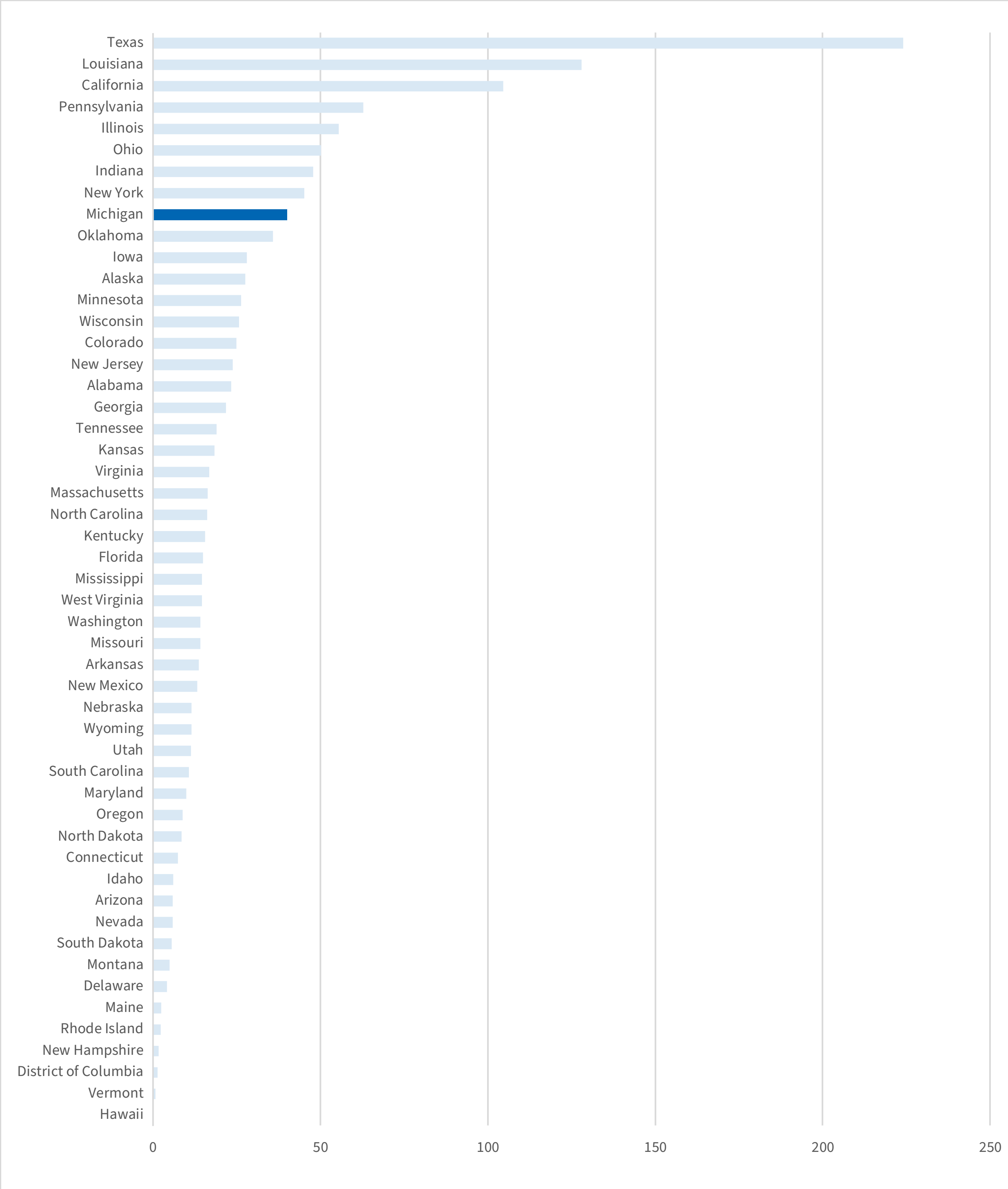
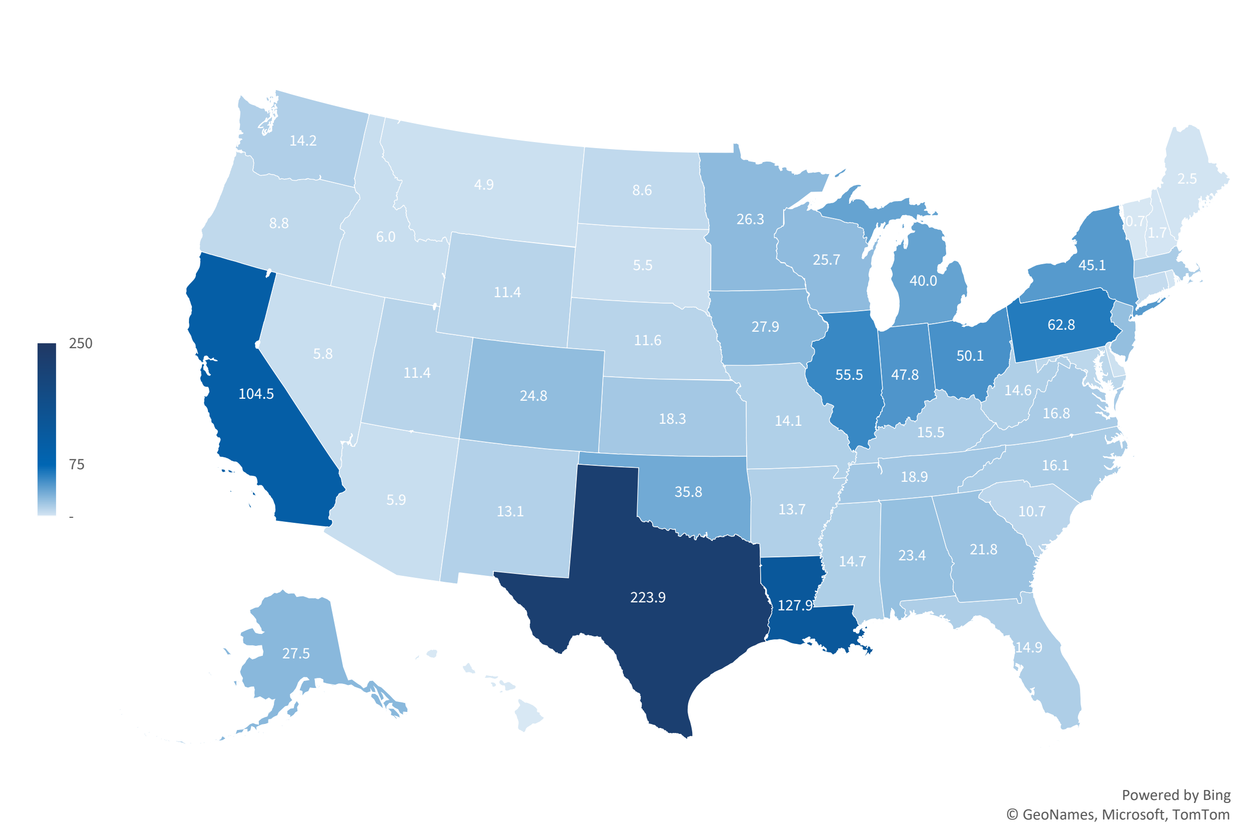


Figure 114: 2019 NOX Emissions from Natural Gas Combustion in All Sectors (Except Electric) in Thousands of Metric Tons



Appendix A: Time Series Tables for Michigan Utility Data

Appendix Table 1: Customer Count

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
DTE Electric Company	1,922,753	1,924,607	1,925,908	1,936,236	1,943,880	1,953,735	1,966,635	1,980,906	1,992,276	2,209,021	1.0%
Consumers Energy Co	1,569,183	1,571,319	1,571,873	1,573,802	1,574,243	1,577,087	1,584,318	1,594,272	1,603,125	1,836,668	1.0%
Indiana Michigan Power Co	109,362	109,162	109,019	109,111	108,929	108,947	109,017	109,725	110,179	129,283	1.0%
Upper Peninsula Power Company	45,845	46,221	46,252	46,279	46,190	42,740	49,562	55,342	52,250	52,889	1.9%
Upper Michigan Energy Resources Corp.	-	-	-	-	-	-	-	32,707	32,763	36,818	6.1%
Alpena Power Co	13,714	13,689	13,681	13,687	13,711	13,718	13,720	13,708	13,686	16,511	1.0%
Northern States Power Co	7,736	7,738	7,740	7,723	7,710	7,669	7,637	7,628	7,599	8,942	0.6%
Great Lakes Energy Coop	111,012	111,226	111,215	112,229	112,071	112,432	113,061	113,765	114,475	126,250	0.9%
City of Lansing	82,887	82,967	82,833	83,143	83,512	83,747	83,910	84,241	84,699	98,268	1.1%
Cloverland Electric Co-op	35,704	36,172	35,998	35,775	35,349	34,630	34,226	34,186	34,383	42,471	0.5%
Cherryland Electric Coop Inc	30,494	30,620	30,754	30,946	31,205	31,520	31,896	32,300	32,738	36,075	1.4%
Midwest Energy Cooperative	28,572	28,523	28,469	28,485	28,487	28,512	28,630	28,767	28,789	34,748	1.2%
Presque Isle Elec & Gas Coop	31,129	30,825	30,878	30,895	30,732	30,760	30,873	31,078	31,107	33,713	0.5%
City of Holland	22,888	23,038	23,134	23,266	23,493	23,645	23,732	23,981	24,349	29,131	1.7%
Tri-County Electric Coop	22,383	22,361	22,314	22,292	22,247	22,241	22,267	22,334	22,388	26,105	0.8%
City of Bay City	17,913	17,737	17,696	17,734	17,696	17,693	17,722	17,858	17,908	20,243	0.7%
City of Marquette	14,151	14,209	14,147	14,700	14,741	14,783	14,833	14,990	14,924	17,230	1.5%
City of Grand Haven	11,580	11,498	11,620	11,731	11,800	11,785	11,883	12,176	12,432	14,403	1.7%
Wyandotte Municipal Serv Comm	11,449	11,344	11,313	11,323	11,335	11,434	11,562	11,633	11,665	12,790	0.9%
City of Traverse City	8,670	8,660	8,775	9,014	9,171	9,202	9,396	9,098	9,709	12,599	2.7%
Thumb Electric Coop of Mich	11,389	11,343	11,304	11,294	11,252	11,220	11,191	11,201	11,217	12,274	0.3%
Alger-Delta Coop Electric Assn	9,469	9,439	9,442	9,458	9,398	9,399	9,449	9,439	9,507	10,089	0.4%
City of South Haven	8,014	7,857	7,769	6,957	6,936	6,976	7,024	7,086	7,109	8,444	-0.4%
City of Escanaba	6,100	6,092	6,063	6,068	6,071	6,063	6,056	6,048	6,035	7,245	0.9%
Coldwater Board of Public Util	5,429	5,525	5,361	5,466	5,594	5,663	5,573	5,671	5,814	7,233	2.0%
City of Sturgis	6,074	6,063	6,059	6,080	6,079	6,054	6,074	6,082	6,089	7,108	0.9%
City of Niles	6,283	6,287	6,297	6,303	6,305	5,990	5,987	5,992	5,978	7,085	0.2%
City of Zeeland	5,249	5,300	5,429	5,485	5,463	5,432	5,514	5,673	5,738	6,749	1.9%
Hillsdale Board of Public Wks	5,344	5,285	5,306	5,284	5,360	5,297	5,031	5,080	5,121	6,024	0.3%
City of Petoskey	4,505	4,335	4,393	4,388	4,390	4,392	4,396	4,417	4,445	5,392	1.1%
Ontonagon County R E A	-	-	-	-	-	-	-	-	-	4,868	0.0%
City of Marshall	3,887	3,884	3,951	3,800	3,857	4,138	4,077	3,874	3,890	4,574	1.0%
City of Charlevoix	-	-	-	-	-	-	-	-	-	4,455	0.0%
City of Harbor Springs	-	-	-	-	-	-	-	-	-	3,712	0.0%
City of Eaton Rapids	-	-	-	-	-	-	-	-	-	3,300	0.0%
City of Gladstone	2,598	2,540	2,511	2,510	2,516	2,512	2,517	2,518	2,521	3,168	1.1%
Village of Chelsea	-	-	-	-	-	-	-	-	-	3,112	0.0%
City of Lowell	-	-	-	-	-	-	-	-	-	2,948	0.0%
City of Dowagiac	-	-	-	-	-	-	-	-	-	2,608	0.0%
City of Portland	-	-	-	-	-	-	-	-	-	2,586	0.0%
City of Negaunee	2,015	2,021	2,020	2,015	2,023	1,980	1,954	1,958	1,959	2,234	0.3%
City of Norway	1,822	1,815	1,827	1,829	1,847	1,843	1,837	1,840	1,843	2,094	0.9%
City of St Louis	-	-	-	-	-	-	-	-	-	1,980	0.0%
Village of Paw Paw	-	-	-	-	-	-	-	-	-	1,759	0.0%
City of Crystal Falls	1,371	1,373	1,358	1,323	1,339	1,344	1,344	1,350	1,336	1,603	0.8%
Village of Union City	-	-	-	-	-	-	-	-	-	1,516	0.0%
Village of Clinton	-	-	-	-	-	-	-	-	-	1,485	0.0%
City of Croswell	-	-	-	-	-	-	-	-	-	1,438	0.0%
Newberry Water & Light Board	-	-	-	-	-	-	-	-	-	1,415	0.0%
City of Hart Hydro	-	-	-	-	-	-	-	-	-	1,410	0.0%
City of Sebewaing	-	-	-	-	-	-	-	-	-	1,282	0.0%
Village of L'Anse	996	989	988	988	990	998	993	989	987	1,176	0.9%
City of Wakefield	-	-	-	-	-	-	-	-	-	1,079	0.0%
Village of Baraga	639	642	643	646	647	653	649	652	540	750	0.2%
City of Stephenson	-	-	-	-	-	-	-	-	-	498	0.0%
Village of Daggett	-	-	-	-	-	-	-	-	-	135	0.0%
Bayfield Electric Coop, Inc	67	67	67	66	66	64	65	65	67	69	0.0%
Wisconsin Electric Power Co	24,441	24,432	24,460	24,456	24,479	24,513	24,586	-	-	1	NA

Appendix Table 2: System Average Interruption Duration Index (SAIDI) with Major Event Days in Minutes

	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
Upper Peninsula Power Company	297	281	161	457	603	137	785	10.5%
Upper Michigan Energy Resources Corp.	-	-	-	-	551	245	723	14.5%
Consumers Energy Co	1,109	377	441	284	606	407	691	-3.3%
Indiana Michigan Power Co	1,188	1,079	526	561	442	609	505	-13.0%
DTE Electric Company	583	793	277	238	1,063	485	466	-1.1%
Northern States Power Co	-	-	157	436	348	222	106	-13.6%
Alpena Power Co	-	146	229	91	131	206	96	-5.6%
Cloverland Electric Co-op	350	608	879	436	871	760	2,040	22.7%
Ontonagon County R E A	-	-	-	-	-	-	1,041	0.0%
Great Lakes Energy Coop	340	250	912	256	335	874	729	14.5%
Presque Isle Elec & Gas Coop	317	196	1,367	442	883	951	659	19.2%
Alger-Delta Coop Electric Assn	53	751	108	82	335	74	583	14.1%
Thumb Electric Coop of Mich	-	-	-	-	-	-	549	0.0%
Midwest Energy Cooperative	1,069	587	107	371	563	385	404	-7.2%
Tri-County Electric Coop	1,057	724	281	519	232	303	270	-19.4%
City of Grand Haven	-	67	52	155	605	209	222	NA
Hillsdale Board of Public Wks	-	-	-	66	76	59	127	18.7%
City of Bay City	-	-	-	55	99	100	100	19.5%
City of Marquette	-	86	30	34	109	39	96	7.6%
City of Niles	-	-	-	-	-	-	90	0.0%
Cherryland Electric Coop Inc	83	75	78	74	109	201	85	8.9%
City of Lowell	-	-	-	-	-	-	68	0.0%
City of Lansing	-	166	139	305	283	92	65	-15.7%
City of Traverse City	-	-	-	-	35	52	64	NA
Coldwater Board of Public Util	37	61	33	82	69	77	64	10.7%
City of Escanaba	-	89	538	27	33	33	48	-27.5%
City of Holland	55	39	28	50	35	37	29	-6.2%
City of Zeeland	-	-	40	6	27	33	27	10.3%
Wyandotte Municipal Serv Comm	25	55	24	19	1	17	1	NA

Appendix Table 3: System Average Interruption Duration Index (SAIDI) without Major Event Days in Minutes

	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
Indiana Michigan Power Co	268	287	311	373	304	314	332	2.9%
Upper Michigan Energy Resources Corp.	-	-	-	-	149	146	238	26.4%
Consumers Energy Co	218	168	177	207	161	201	233	1.7%
Upper Peninsula Power Company	248	248	122	165	176	137	212	-4.5%
DTE Electric Company	180	189	187	180	196	177	202	1.0%
Northern States Power Co	-	-	157	283	135	130	100	-15.4%
Alpena Power Co	-	64	97	91	66	92	96	4.6%
Ontonagon County R E A	-	-	-	-	-	-	442	0.0%
Cloverland Electric Co-op	284	254	210	352	208	208	325	0.0%
Midwest Energy Cooperative	462	291	107	371	452	329	303	1.5%
Presque Isle Elec & Gas Coop	180	196	227	275	288	259	279	7.8%
Thumb Electric Coop of Mich	-	-	-	-	-	-	269	0.0%
Great Lakes Energy Coop	177	136	175	160	178	159	176	1.1%
Tri-County Electric Coop	259	243	179	179	139	249	156	-6.0%
City of Bay City	-	-	-	55	99	100	100	19.5%
City of Niles	-	-	-	-	-	-	90	0.0%
Cherryland Electric Coop Inc	83	75	78	74	69	158	75	3.9%
City of Traverse City	-	-	-	-	35	52	64	NA
Alger-Delta Coop Electric Assn	52	476	107	75	73	74	56	-12.9%
Hillsdale Board of Public Wks	-	-	-	-	-	-	54	0.0%
City of Lansing	-	81	43	113	68	60	46	-6.6%
City of Marquette	50	86	21	34	109	17	36	-9.0%
City of Lowell	-	-	-	-	-	-	32	0.0%
City of Holland	35	28	18	19	21	22	29	-3.3%
City of Zeeland	-	-	40	6	27	33	27	10.3%
City of Grand Haven	275	-	-	155	6	5	13	NA

Appendix Table 4: Customer Average Interruption Duration Index (CAIDI) with Major Event Days in Minutes

	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
Consumers Energy Co	555	342	373	247	462	314	437	-2.4%
DTE Electric Company	530	650	277	241	765	358	340	-5.2%
Upper Michigan Energy Resources Corp.	-	-	-	-	298	211	336	6.3%
Upper Peninsula Power Company	149	152	124	218	274	118	316	9.6%
Indiana Michigan Power Co	655	640	302	294	219	342	237	-15.2%
Northern States Power Co	-	-	157	186	264	204	155	0.7%
Alpena Power Co	-	146	153	76	109	109	107	-6.1%
Alger-Delta Coop Electric Assn	190.79	449.46	99.45	204.00	339.01	222.96	837.35	16.4%
Cloverland Electric Co-op	182	214	424	179	275	267	452	10.2%
Ontonagon County R E A	-	-	-	-	-	-	333	0.0%
Presque Isle Elec & Gas Coop	230	148	595	244	321	358	306	7.4%
Thumb Electric Coop of Mich	-	-	-	-	-	-	272	0.0%
Great Lakes Energy Coop	184	169	402	141	162	358	268	6.4%
Midwest Energy Cooperative	356	263	108	199	201	175	202	-6.6%
City of Grand Haven	-	84	119	75	289	100	185	14.7%
Tri-County Electric Coop	513	286	167	290	153	153	178	-14.9%
City of Marquette	-	70	75	67	118	98	135	14.2%
City of Lowell	-	-	-	-	-	-	123	0.0%
City of Bay City	-	-	-	105.97	160.31	87.01	121.64	-2.0%
City of Niles	-	-	-	-	-	-	107	0.0%
City of Traverse City	-	-	-	-	82	79	105	12.9%
Cherryland Electric Coop Inc	146.13	121.39	107.40	109.71	133.70	149.78	96.10	-2.2%
City of Escanaba	-	139	566	144	102	127	92	-17.8%
Wyandotte Municipal Serv Comm	89	138	800	96	199	212	75	-3.7%
City of Holland	97	68	71	108	71	99	71	-0.8%
City of Lansing	-	187	129	183	272	128	61	-13.9%
Hillsdale Board of Public Wks	-	-	-	27	86	37	55	13.7%
Coldwater Board of Public Util	66	66	46	49	67	31	48	-7.3%
City of Zeeland	-	-	38	11	23	63	30	13.9%

Appendix Table 5: Customer Average Interruption Duration Index (CAIDI) without Major Event Days in Minutes

	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
Consumers Energy Co	218	184	180	206	181	198	208	0.0%
Indiana Michigan Power Co	207	221	212	217	174	208	194	-1.8%
DTE Electric Company	244	249	205	197	198	170	178	-6.0%
Upper Michigan Energy Resources Corp.	-	-	-	-	152	160	159	2.2%
Northern States Power Co	-	-	157	134	159	183	151	2.5%
Upper Peninsula Power Company	124	139	111	127	135	118	119	-0.9%
Alpena Power Co	-	107	88	76	82	92	107	0.7%
Alger-Delta Coop Electric Assn	-	331	99	188	74	223	477	10.0%
Presque Isle Elec & Gas Coop	172	148	172	191	191	174	219	4.1%
Ontonagon County R E A	-	-	-	-	-	-	202	0.0%
Thumb Electric Coop of Mich	-	-	-	-	-	-	187	0.0%
Midwest Energy Cooperative	231	156	108	199	181	157	178	-0.9%
City of Marquette	74	70	71	67	118	80	145	10.4%
Cloverland Electric Co-op	163	126	126	157	129	114	142	-2.1%
Tri-County Electric Coop	161.88	109.46	120.13	122.60	103.73	131.75	126.83	-1.8%
City of Bay City	-	-	-	106	160	87	122	-2.0%
City of Grand Haven	162.72	-	-	75.17	88.62	88.47	121.38	NA
Great Lakes Energy Coop	120	114	130	110	119	113	112	-1.2%
City of Lowell	-	-	-	-	-	-	109.08	0.0%
City of Niles	-	-	-	-	-	-	107	0.0%
City of Traverse City	-	-	-	-	82	79	105	12.9%
Cherryland Electric Coop Inc	146	121	107	110	121	132	88	-4.3%
City of Holland	75	57	57	79	89	88	71	4.0%
City of Lansing	-	98	89	108	105	103	49	-8.4%
City of Zeeland	-	-	38	11	23	63	30	13.9%

Appendix Table 6: System Average Frequency Interruption Index (SAIFI) with Major Event Days in Number of Outages

	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
Upper Peninsula Power Company	2.00	1.85	1.30	2.10	2.20	1.16	2.48	0.9%
Upper Michigan Energy Resources Corp.	-	-	-	-	1.85	1.16	2.15	7.8%
Indiana Michigan Power Co	1.82	1.69	1.74	1.91	2.01	1.78	2.13	2.7%
Consumers Energy Co	2.00	1.10	1.18	1.15	1.31	1.30	1.58	-1.0%
DTE Electric Company	1.10	1.22	1.00	0.99	1.39	1.36	1.37	4.4%
Alpena Power Co	-	1.00	1.50	1.20	1.20	1.90	0.90	0.5%
Northern States Power Co	-	-	1.00	2.34	1.32	1.09	0.68	-14.2%
Cloverland Electric Co-op	1.92	2.84	2.07	2.43	3.17	2.85	4.51	11.3%
Ontonagon County R E A	-	-	-	-	-	-	3.13	0.0%
Great Lakes Energy Coop	1.85	1.48	2.27	1.82	2.07	2.44	2.72	7.6%
Hillsdale Board of Public Wks	-	-	-	2.41	0.89	1.58	2.30	4.4%
Presque Isle Elec & Gas Coop	1.38	1.32	2.30	1.81	2.75	2.65	2.15	11.0%
Thumb Electric Coop of Mich	-	-	-	-	-	-	2.02	0.0%
Midwest Energy Cooperative	3.00	2.23	0.99	1.87	2.80	2.20	2.00	-0.7%
Tri-County Electric Coop	2.06	2.53	1.68	1.79	1.52	1.98	1.52	-5.2%
Coldwater Board of Public Util	0.56	0.92	0.70	1.67	1.02	2.50	1.33	19.5%
City of Grand Haven	-	0.80	0.44	2.06	2.09	2.08	1.20	21.2%
City of Lansing	-	0.89	1.08	1.67	1.04	0.72	1.08	-2.0%
City of Zeeland	-	-	1.03	0.54	1.17	0.53	0.89	-3.1%
Cherryland Electric Coop Inc	0.57	0.61	0.73	0.68	0.82	1.34	0.89	11.4%
City of Niles	-	-	-	-	-	-	0.84	0.0%
City of Bay City	-	-	-	0.52	0.62	1.15	0.82	21.8%
City of Marquette	-	1.22	0.40	0.50	0.93	0.40	0.71	-5.8%
Alger-Delta Coop Electric Assn	0.28	1.67	1.09	0.40	0.99	0.33	0.70	-2.0%
City of Traverse City	-	-	-	-	0.43	0.66	0.62	19.6%
City of Lowell	-	-	-	-	-	-	0.55	0.0%
City of Escanaba	1.03	0.64	0.95	0.19	0.32	0.26	0.52	-16.2%
City of Holland	0.57	0.57	0.40	0.46	0.49	0.38	0.41	-5.5%
Wyandotte Municipal Serv Comm	0.28	0.40	0.03	0.20	0.00	0.08	0.01	NA

Appendix Table 7: System Average Frequency Interruption Index (SAIFI) without Major Event Days in Number of Outages

	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
Indiana Michigan Power Co	268.00	286.90	310.60	373.00	303.50	313.50	332.20	2.9%
Upper Michigan Energy Resources Corp.	-	-	-	-	149.00	146.00	238.00	26.4%
Consumers Energy Co	218.00	168.40	177.00	207.00	160.90	200.90	233.34	1.7%
Upper Peninsula Power Company	248.00	248.00	121.90	164.90	176.10	136.90	211.50	-4.5%
DTE Electric Company	180.00	189.00	187.00	180.00	196.00	177.19	202.38	1.0%
Northern States Power Co	-	-	156.53	283.17	135.46	130.04	99.85	-15.4%
Alpena Power Co	-	64.00	96.70	91.00	65.80	91.90	96.30	4.6%
Ontonagon County R E A	-	-	-	-	-	-	442.20	0.0%
Cloverland Electric Co-op	284.00	254.00	209.50	352.40	207.70	208.10	324.80	0.0%
Midwest Energy Cooperative	462.00	291.39	107.23	371.30	452.00	329.40	303.00	1.5%
Presque Isle Elec & Gas Coop	180.00	195.53	227.49	275.00	288.10	259.20	278.90	7.8%
Thumb Electric Coop of Mich	-	-	-	-	-	-	269.02	0.0%
Great Lakes Energy Coop	177.00	136.20	175.04	160.19	177.97	159.46	176.10	1.1%
Tri-County Electric Coop	259.00	243.00	179.00	179.00	139.00	249.00	156.00	-6.0%
City of Bay City	-	-	-	55.42	99.23	99.97	99.99	19.5%
City of Niles	-	-	-	-	-	-	90.03	0.0%
Cherryland Electric Coop Inc	83.00	74.53	77.87	74.27	68.70	158.20	74.91	3.9%
City of Traverse City	-	-	-	-	35.29	52.29	64.28	NA
Alger-Delta Coop Electric Assn	51.74	476.20	107.40	75.20	72.66	74.24	55.85	-12.9%
Hillsdale Board of Public Wks	-	-	-	-	-	-	54.13	0.0%
City of Lansing	-	81.00	43.40	112.78	67.95	59.88	45.76	-6.6%
City of Marquette	50.00	85.60	21.37	33.68	108.99	16.58	36.14	-9.0%
City of Lowell	-	-	-	-	-	-	31.63	0.0%
City of Holland	35.00	28.38	18.18	18.95	20.85	21.87	29.08	-3.3%
City of Zeeland	-	-	39.51	5.90	27.29	33.50	27.07	10.3%
City of Grand Haven	275.00	-	-	154.86	5.76	5.49	13.23	NA
Indiana Michigan Power Co	268.00	286.90	310.60	373.00	303.50	313.50	332.20	2.9%
Upper Michigan Energy Resources Corp.	-	-	-	-	149.00	146.00	238.00	26.4%
Consumers Energy Co	218.00	168.40	177.00	207.00	160.90	200.90	233.34	1.7%

Appendix Table 8: Natural Gas Losses in Millions of Cubic Feet

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
DTE Gas Company	3,800,000	3,800,000	3,800,000	1,400,000	1,600,000	1,653,000	1,557,000	4,379,714	3,711,115	7,742,053	4.5%
Consumers Energy Company	780,568	842,416	812,797	863,854	913,618	875,184	884,583	870,501	953,027	969,860	2.0%
Michigan Gas Utilities Company	98,014	107,084	65,824	130,116	142,509	96,181	103,547	97,065	108,341	110,623	1.2%
Upper Michigan Energy Resources Corporation		1,321	3,939	7,239	15,936	14,290	15,211	15,217	16,875	16,987	NA
Northern States Power Company	2,715	3,082	1,959	3,955	4,076	2,542	2,914	2,723	2,925	2,862	0.2%
Aurora Gas Company	759	877	518	1,008	1,177	873	848	786	393		
Blue Lake Gas Storage Company										500,000	0.0%
Northern Natural Gas	29,195	28,990	35,128	39,047	43,928	46,690	42,299	37,655	37,170	56,448	5.2%
SEMCO Pipeline Inc	30,799	27,839	25,611	26,053	20,304	13,032	26,667	29,822	40,387	40,814	3.4%
Panhandle Eastern Pipeline Company	49,584	51,681	35,319	56,177	46,500	27,822	33,256	30,814	29,002	30,426	-6.6%
Vector Pipeline Company		27,342	16,191	86,782	15,877	25,077	17,449	80,798	18,751	14,166	-3.7%
Citizens Gas Fuel Company	8,947	23,802	2,334	12,049	13,456	8,668	8,586	8,462	9,086	9,101	-1.0%
Presque Isle Electric & Gas Cooperative	2,006	2,356	578	719	848	746	688	737	983	1,182	-5.8%

Appendix Table 9: Unaccounted for Natural Gas in Millions of Cubic Feet

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SEMCO Energy Gas Company	(90,634)	376,460	(10,990)	87,152	59,652	(119,755)	330,056	(81,614)	(282,932)	
DTE Gas Company	8,180,371	9,550,191	4,019,087	4,019,123	5,048,994	3,687,637	(8,656)	737		
Consumers Energy Company	2,119,482	(1,397,989)	1,586,413	3,931,908	2,068,374	2,591,118	1,986,957	370,570	5,601,307	2,994,474
Michigan Gas Utilities Company	(646,777)	778,430	(341,119)	23,437	(448,673)	(296,444)	(117,986)	(182,430)	(285,168)	(529,500)
Upper Michigan Energy Resources Corporation	4,412	14,122	25,299	24,486	23,695	(15,577)	(19,892)	11,362	721	(1,963)
Northern States Power Company	(1,442)	(12,809)	(23,833)	(791)	22,690	5,154	28,564	14,275	(30,120)	9,215
ANR Pipeline Company	196,348	(207,121)	101,255	285,091	283,110	336,607	280,126	514,147	440,707	
Blue Lake Gas Storage Company										(500,000)
Citizens Gas Fuel Company	2,010	(63,963)	6,539	1,820	(174,140)	(11,828)	105,426	(11,215)	(66,452)	97,522
Great Lakes Gas Transmission LP	(617,355)	470,948	582,697	814,314	254,289	1,173,536	1,145,507	228,391	71,616	
Lee 8 Storage Partnership	227,562	(52,618)	(40,139)	(58,875)	(41,083)	(59,065)	(44,269)	(41,400)	(225,210)	
NEXUS									71,438	
Northern Natural Gas	(4,430)	12,618	14,243	14,720	7,486	(7,226)	5,251	11,894	(1,310)	13,461
Panhandle Eastern Pipeline Company	(58,481)	(39,619)	729	(123,187)	(276,287)	(291,035)	(72,461)	188,892	153,070	1,098,457
Presque Isle Electric & Gas Cooperative	24,946	13,988	(2,547)	30,385	47,917	10,551	19,574	19,015	(4,083)	34,011
Rover Pipeline Company									(125,844)	
SEMCO Pipeline Inc	(40,311)	(251,581)	(64,734)	(120,755)	(116,887)	(54,746)	(71,679)	(52,726)	(107,183)	(107,610)
Southwest Gas Storage Company	1,488,393	(390,776)	(270,981)	(373,011)	(518,469)	(388,323)	(267,286)	(301,035)	(266,957)	
Washington 10			(989,642)	(621,230)	(847,318)	(830,653)	(489,958)	(575,464)	(636,497)	

Appendix Table 10: Cost per Kilowatt Hour of Electricity in the Residential Sector

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
Upper Peninsula Power Company	$0.17	$0.18	$0.19	$0.21	$0.22	$0.23	$0.24	$0.24	$0.22	$0.22	3.1%
DTE Electric Company	$0.13	$0.14	$0.15	$0.15	$0.15	$0.15	$0.16	$0.16	$0.16	$0.16	2.0%
Consumers Energy Co	$0.13	$0.13	$0.14	$0.14	$0.15	$0.15	$0.15	$0.16	$0.16	$0.16	2.4%
Alpena Power Co	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14	$0.13	$0.14	$0.14	$0.15	0.3%
Upper Michigan Energy Resources Corp.	$-	$-	$-	$-	$-	$-	$-	$0.15	$0.15	$0.14	-2.5%
Indiana Michigan Power Co	$0.08	$0.09	$0.10	$0.10	$0.10	$0.11	$0.11	$0.11	$0.13	$0.14	5.7%
Northern States Power Co	$0.10	$0.10	$0.11	$0.11	$0.12	$0.12	$0.12	$0.13	$0.12	$0.12	2.7%
Bayfield Electric Coop, Inc	$0.23	$0.25	$0.28	$0.29	$0.29	$0.31	$0.29	$0.29	$0.30	$0.30	2.5%
Ontonagon County R E A	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.27	0.0%
Alger-Delta Coop Electric Assn	$0.20	$0.20	$0.21	$0.21	$0.21	$0.21	$0.21	$0.21	$0.21	$0.21	0.1%
City of Marquette	$0.09	$0.09	$0.10	$0.10	$0.11	$0.12	$0.14	$0.17	$0.17	$0.17	8.3%
City of Negaunee	$0.17	$0.18	$0.16	$0.16	$0.16	$0.17	$0.18	$0.18	$0.17	$0.17	0.1%
City of Lansing	$0.11	$0.12	$0.13	$0.13	$0.14	$0.15	$0.15	$0.15	$0.15	$0.16	3.9%
City of Crystal Falls	$0.15	$0.15	$0.15	$0.15	$0.15	$0.16	$0.16	$0.16	$0.16	$0.16	0.7%
Great Lakes Energy Coop	$0.13	$0.14	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.15	$0.16	1.3%
Midwest Energy Cooperative	$0.12	$0.14	$0.15	$0.15	$0.15	$0.16	$0.16	$0.16	$0.14	$0.15	1.8%
Presque Isle Elec & Gas Coop	$0.14	$0.14	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.16	$0.15	1.1%
City of Norway	$0.13	$0.13	$0.14	$0.13	$0.14	$0.14	$0.15	$0.15	$0.15	$0.15	2.1%
Tri-County Electric Coop	$0.12	$0.13	$0.14	$0.14	$0.14	$0.14	$0.14	$0.14	$0.15	$0.15	1.9%
Wyandotte Municipal Serv Comm	$0.09	$0.13	$0.14	$0.15	$0.15	$0.15	$0.15	$0.15	$0.14	$0.15	3.1%
City of Dowagiac	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.15	0.0%
Cherryland Electric Coop Inc	$0.12	$0.12	$0.14	$0.14	$0.13	$0.14	$0.14	$0.14	$0.14	$0.15	1.6%
City of Sturgis	$0.11	$0.12	$0.12	$0.12	$0.12	$0.13	$0.13	$0.14	$0.14	$0.14	2.9%
City of Grand Haven	$0.12	$0.12	$0.13	$0.13	$0.14	$0.15	$0.15	$0.14	$0.14	$0.14	1.7%
Village of Clinton	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.14	0.0%
Thumb Electric Coop of Mich	$0.12	$0.12	$0.11	$0.11	$0.12	$0.12	$0.12	$0.13	$0.14	$0.13	1.9%
City of Gladstone	$0.13	$0.15	$0.15	$0.12	$0.13	$0.12	$0.12	$0.13	$0.13	$0.13	-1.0%
City of Marshall	$0.13	$0.12	$0.13	$0.14	$0.15	$0.14	$0.13	$0.13	$0.13	$0.13	0.3%
Village of Baraga	$0.13	$0.12	$0.12	$0.13	$0.13	$0.13	$0.21	$0.13	$0.13	$0.13	1.6%
City of St Louis	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.13	0.0%
City of Bay City	$0.10	$0.10	$0.10	$0.11	$0.12	$0.12	$0.12	$0.13	$0.13	$0.13	3.4%
Village of Paw Paw	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.13	0.0%
Cloverland Electric Co-op	$0.11	$0.11	$0.11	$0.11	$0.12	$0.12	$0.13	$0.13	$0.13	$0.13	2.0%
Village of L'Anse	$0.12	$0.12	$0.13	$0.14	$0.14	$0.15	$0.14	$0.15	$0.14	$0.13	1.1%
City of Lowell	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.13	0.0%
City of Escanaba	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.12	$0.12	$0.12	1.4%
City of Eaton Rapids	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
City of Holland	$0.10	$0.10	$0.10	$0.11	$0.11	$0.11	$0.12	$0.12	$0.12	$0.12	2.8%
Hillsdale Board of Public Wks	$0.12	$0.11	$0.12	$0.12	$0.13	$0.13	$0.12	$0.14	$0.12	$0.12	1.0%
Village of Union City	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
City of Portland	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
City of Sebewaing	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
City of Hart Hydro	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
Coldwater Board of Public Util	$0.12	$0.12	$0.12	$0.12	$0.13	$0.12	$0.12	$0.12	$0.12	$0.11	-0.4%
City of Petoskey	$0.09	$0.10	$0.10	$0.11	$0.11	$0.12	$0.12	$0.11	$0.11	$0.11	2.3%
City of Niles	$0.10	$0.10	$0.10	$0.10	$0.11	$0.11	$0.12	$0.12	$0.12	$0.11	2.5%
City of Charlevoix	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.11	0.0%
City of South Haven	$0.11	$0.11	$0.11	$0.12	$0.11	$0.11	$0.12	$0.14	$0.15	$0.11	2.2%
City of Stephenson	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.11	0.0%
City of Wakefield	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.11	0.0%
Village of Daggett	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.11	0.0%
City of Traverse City	$0.09	$0.10	$0.10	$0.10	$0.12	$0.11	$0.11	$0.11	$0.11	$0.10	1.6%
Newberry Water & Light Board	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.10	0.0%
City of Croswell	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.10	0.0%
Village of Chelsea	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.10	0.0%
City of Harbor Springs	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.09	0.0%
City of Zeeland	$0.08	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	0.2%

Appendix Table 11: Natural Gas Price per Therm

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
SEMCO Energy Gas Company	$8.82	$8.49	$8.05	$7.71	$9.00	$7.73	$7.23	$7.40	$7.04	$6.93	-2.5%
DTE Gas Company	$11.63	$10.26	$9.86	$9.13	$9.22	$9.03	$8.75	$8.92	$8.50	$8.19	-3.1%
Consumers Energy Company	$11.61	$10.94	$10.43	$9.36	$9.53	$8.94	$8.10	$8.25	$8.25	$8.29	-4.0%
Michigan Gas Utilities Company	$10.33	$9.92	$7.87	$7.64	$8.19	$7.31	$7.03	$7.67	$7.10	$6.67	-4.0%
Upper Michigan Energy Resources Corporation	$7.70	$7.33	$6.44	$6.65	$7.38	$7.73	$5.71	$6.07	$5.41	$5.54	-3.4%
Northern States Power Company	$7.78	$7.13	$6.57	$6.79	$7.91	$8.30	$6.81	$7.34	$7.14	$7.52	0.2%
Aurora Gas Company	$13.52	$12.53	$11.58	$11.27	$10.80	$10.27	$11.88	$9.65	$10.78		
Citizens Gas Fuel Company	$9.78	$9.64	$10.00	$9.90	$9.52	$9.89	$7.75	$8.02	$8.20	$7.58	-3.1%
Presque Isle Electric & Gas Cooperative	$14.19	$13.07	$13.03	$12.16	$11.51	$11.79	$11.72	$10.83	$10.64	$10.28	-3.2%

Appendix Table 12: Cost per Kilowatt Hour of Electricity in the Commercial Sector

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
Upper Peninsula Power Company	$0.14	$0.15	$0.15	$0.16	$0.17	$0.16	$0.16	$0.17	$0.15	$0.17	1.4%
Consumers Energy Co	$0.11	$0.11	$0.12	$0.12	$0.13	$0.12	$0.12	$0.13	$0.13	$0.13	1.9%
Upper Michigan Energy Resources Corp.	$-	$-	$-	$-	$-	$-	$-	$0.14	$0.14	$0.13	-3.6%
Alpena Power Co	$0.12	$0.12	$0.12	$0.12	$0.12	$0.12	$0.11	$0.12	$0.12	$0.13	0.3%
Indiana Michigan Power Co	$0.08	$0.09	$0.09	$0.09	$0.09	$0.10	$0.10	$0.10	$0.11	$0.12	3.7%
Northern States Power Co	$0.09	$0.09	$0.10	$0.10	$0.11	$0.11	$0.11	$0.12	$0.11	$0.11	3.0%
DTE Electric Company	$0.09	$0.10	$0.11	$0.11	$0.10	$0.10	$0.10	$0.10	$0.11	$0.11	0.3%
Ontonagon County R E A	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.26	0.0%
City of Sturgis	$0.13	$0.14	$0.14	$0.15	$0.14	$0.15	$0.15	$0.16	$0.17	$0.17	2.3%
Alger-Delta Coop Electric Assn	$0.16	$0.15	$0.16	$0.16	$0.15	$0.16	$0.15	$0.16	$0.16	$0.16	0.1%
Tri-County Electric Coop	$0.14	$0.14	$0.15	$0.15	$0.16	$0.15	$0.15	$0.15	$0.16	$0.15	1.2%
City of Marquette	$0.08	$0.08	$0.09	$0.10	$0.10	$0.11	$0.13	$0.16	$0.16	$0.15	8.6%
City of Dowagiac	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.15	0.0%
City of Crystal Falls	$0.12	$0.13	$0.13	$0.13	$0.14	$0.14	$0.14	$0.14	$0.15	$0.14	1.7%
Great Lakes Energy Coop	$0.11	$0.11	$0.12	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.14	2.0%
City of Norway	$0.13	$0.12	$0.13	$0.12	$0.12	$0.14	$0.14	$0.13	$0.13	$0.13	0.9%
City of Lansing	$0.09	$0.10	$0.11	$0.12	$0.12	$0.13	$0.13	$0.13	$0.13	$0.13	3.6%
Midwest Energy Cooperative	$0.09	$0.08	$0.09	$0.09	$0.09	$0.09	$0.10	$0.10	$0.11	$0.13	3.7%
Village of Union City	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.13	0.0%
City of Grand Haven	$0.14	$0.15	$0.15	$0.15	$0.15	$0.14	$0.13	$0.13	$0.13	$0.13	-1.6%
Village of Baraga	$0.13	$0.13	$0.13	$0.13	$0.12	$0.12	$0.19	$0.13	$0.13	$0.13	0.4%
City of Negaunee	$0.12	$0.12	$0.12	$0.12	$0.12	$0.13	$0.13	$0.13	$0.13	$0.13	1.3%
Wyandotte Municipal Serv Comm	$0.11	$0.16	$0.15	$0.16	$0.16	$0.12	$0.12	$0.12	$0.12	$0.13	-1.3%
Village of L'Anse	$0.11	$0.11	$0.12	$0.13	$0.13	$0.13	$0.12	$0.13	$0.12	$0.12	1.0%
City of St Louis	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
City of Lowell	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
City of Bay City	$0.10	$0.10	$0.10	$0.10	$0.11	$0.11	$0.11	$0.12	$0.12	$0.12	3.5%
City of Niles	$0.10	$0.10	$0.10	$0.11	$0.11	$0.12	$0.12	$0.12	$0.13	$0.12	3.3%
City of Sebewaing	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
City of Stephenson	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
Village of Clinton	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
City of Portland	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
City of Marshall	$0.14	$0.12	$0.12	$0.12	$0.13	$0.12	$0.11	$0.12	$0.12	$0.12	-1.5%
City of Gladstone	$0.12	$0.12	$0.10	$0.12	$0.14	$0.11	$0.10	$0.11	$0.12	$0.12	-0.1%
City of Charlevoix	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.12	0.0%
City of Hart Hydro	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.11	0.0%
City of Eaton Rapids	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.11	0.0%
City of Croswell	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.11	0.0%
Village of Daggett	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.11	0.0%
Cloverland Electric Co-op	$0.10	$0.11	$0.11	$0.10	$0.11	$0.10	$0.11	$0.10	$0.11	$0.11	0.5%
Hillsdale Board of Public Wks	$0.10	$0.10	$0.10	$0.11	$0.12	$0.11	$0.10	$0.12	$0.11	$0.11	1.2%
City of Holland	$0.08	$0.09	$0.09	$0.09	$0.10	$0.10	$0.11	$0.11	$0.10	$0.11	3.1%
Thumb Electric Coop of Mich	$0.11	$0.11	$0.10	$0.10	$0.09	$0.08	$0.08	$0.11	$0.10	$0.11	-0.5%
Coldwater Board of Public Util	$0.11	$0.11	$0.12	$0.12	$0.12	$0.10	$0.10	$0.11	$0.10	$0.11	-1.8%
City of Traverse City	$0.09	$0.10	$0.10	$0.10	$0.12	$0.11	$0.11	$0.11	$0.11	$0.10	1.2%
Cherryland Electric Coop Inc	$0.09	$0.10	$0.10	$0.11	$0.11	$0.10	$0.10	$0.10	$0.10	$0.10	0.4%
Presque Isle Elec & Gas Coop	$0.10	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.10	-0.1%
City of Petoskey	$0.08	$0.09	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10	1.5%
City of Wakefield	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.10	0.0%
City of Harbor Springs	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.10	0.0%
City of Escanaba	$0.10	$0.10	$0.10	$0.09	$0.09	$0.09	$0.10	$0.09	$0.10	$0.10	-0.3%
Village of Chelsea	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.09	0.0%
Village of Paw Paw	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.09	0.0%
City of Zeeland	$0.08	$0.09	$0.09	$0.09	$0.10	$0.09	$0.09	$0.09	$0.09	$0.08	-0.5%
City of South Haven	$0.10	$0.10	$0.10	$0.11	$0.10	$0.10	$0.11	$0.12	$0.13	$0.08	0.5%
Newberry Water & Light Board	$-	$-	$-	$-	$-	$-	$-	$-	$-	$0.08	0.0%

Appendix Table 13: Cost per Kilowatt Hour of Electricity in the Industrial Sector

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Trend CAGR
Indiana Michigan Power Co	$0.06	$0.07	$0.08	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09	$0.10	4.0%
Consumers Energy Co	$0.08	$0.08	$0.08	$0.09	$0.09	$0.08	$0.08	$0.08	$0.08	$0.08	-0.5%
DTE Electric Company	$0.06	$0.07	$0.08	$0.08	$0.08	$0.07	$0.07	$0.07	$0.07	$0.07	-0.8%
Northern States Power Co	$0.07	$0.07	$0.07	$0.07	$0.08	$0.07	$0.07	$0.07	$0.06	$0.06	-0.4%
Alpena Power Co	$0.06	$0.06	$0.06	$0.06	$0.07	$0.06	$0.06	$0.06	$0.07	$0.06	-0.2%
Upper Peninsula Power Company	$0.06	$0.06	$0.05	$0.06	$0.07	$0.06	$0.09	$0.07	$0.05	$0.05	0.1%
Upper Michigan Energy Resources Corp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.07	$0.07	$0.05	-12.9%
Alger-Delta Coop Electric Assn	$ -	$ -	$ -	$0.14	$0.14	$0.14	$0.13	$0.13	$0.17	$0.19	5.0%
Cherryland Electric Coop Inc	$ -	$ -	$ -	$0.13	$0.13	$0.13	$0.13	$0.14	$0.13	$0.14	0.3%
City of Dowagiac	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.12	0.0%
Village of Clinton	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.12	0.0%
City of Wakefield	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.12	0.0%
City of Lansing	$0.08	$0.08	$0.09	$0.10	$0.10	$0.11	$0.10	$0.11	$0.10	$0.11	3.6%
City of Grand Haven	$0.09	$0.09	$0.09	$0.10	$0.10	$0.11	$0.11	$0.11	$0.11	$0.11	2.7%
City of Bay City	$0.07	$0.08	$0.09	$0.09	$0.10	$0.09	$0.10	$0.11	$0.10	$0.11	4.2%
City of Stephenson	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.11	0.0%
Presque Isle Elec & Gas Coop	$0.10	$0.11	$0.12	$0.12	$0.12	$0.11	$0.11	$0.12	$0.11	$0.11	0.2%
City of Croswell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.11	0.0%
City of Sturgis	$0.08	$0.09	$0.09	$0.09	$0.10	$0.10	$0.10	$0.10	$0.11	$0.11	2.5%
City of St Louis	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.10	0.0%
City of Petoskey	$0.10	$0.10	$0.11	$0.12	$0.11	$0.11	$0.11	$0.11	$0.11	$0.10	0.3%
City of Marshall	$0.10	$0.10	$0.09	$0.10	$0.12	$0.10	$0.10	$0.10	$0.10	$0.10	0.7%
City of Hart Hydro	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.10	0.0%
City of Portland	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.10	0.0%
City of Sebewaing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.09	0.0%
Tri-County Electric Coop	$0.09	$0.09	$0.10	$0.10	$0.10	$0.10	$0.10	$0.09	$0.09	$0.09	0.1%
City of Lowell	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.09	0.0%
City of Eaton Rapids	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.09	0.0%
Cloverland Electric Co-op	$0.07	$0.08	$0.08	$0.07	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	1.3%
Hillsdale Board of Public Wks	$0.09	$0.09	$0.09	$0.10	$0.10	$0.10	$0.08	$0.09	$0.09	$0.08	-0.4%
City of Escanaba	$0.09	$0.09	$0.09	$0.08	$0.08	$0.08	$0.09	$0.08	$0.08	$0.08	-0.8%
Great Lakes Energy Coop	$0.07	$0.07	$0.08	$0.08	$0.09	$0.08	$0.08	$0.08	$0.08	$0.08	1.5%
Village of Chelsea	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.08	0.0%
City of Charlevoix	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.08	0.0%
City of Holland	$0.07	$0.07	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09	$0.08	$0.08	1.7%
Wyandotte Municipal Serv Comm	$0.07	$0.10	$0.11	$0.10	$0.10	$0.09	$0.09	$0.08	$0.08	$0.08	-1.1%
City of Niles	$0.07	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09	$0.08	1.4%
Village of Paw Paw	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.08	0.0%
Ontonagon County R E A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.07	0.0%
City of Traverse City	$0.07	$0.08	$0.08	$0.08	$0.10	$0.08	$0.08	$0.08	$0.07	$0.07	0.4%
Coldwater Board of Public Util	$0.09	$0.09	$0.08	$0.08	$0.08	$0.07	$0.07	$0.08	$0.07	$0.07	-2.5%
City of Zeeland	$0.07	$0.07	$0.07	$0.08	$0.08	$0.07	$0.07	$0.07	$0.07	$0.07	-0.5%
Wisconsin Electric Power Co	$0.06	$0.06	$0.06	$0.07	$0.08	$0.06	$0.06	$0.06	$0.06	$0.06	0.2%
City of South Haven	$0.08	$0.07	$0.08	$0.08	$0.07	$0.07	$0.08	$0.09	$0.10	$0.05	-0.5%
City of Harbor Springs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0.01	0.0%

Appendix B: Historical Reliability Data

Appendix Table 14: System Average Interruption Duration Index (SAIDI) with Major Event Days in Minutes

	2013	2014	2015	2016	2017	2018	2019	Rank	CAGR
Alabama	230	197	209	174	316	308	174	33	-4.5%
Alaska	358	253	597	195	153	335	280	19	-4.0%
Arizona	74	84	90	86	91	115	86	49	2.6%
Arkansas	251	212	303	397	395	323	438	8	9.7%
California	98	103	118	117	233	195	587	3	34.7%
Colorado	127	83	109	164	228	113	181	32	6.0%
Connecticut	79	86	104	174	291	656	236	29	20.0%
Delaware	158	169	190	149	154	136	102	46	-7.1%
District of Columbia	124	96	112	115	58	109	77	51	-7.6%
Florida	82	92	85	337	2,381	310	88	47	1.3%
Georgia	138	235	241	420	1,042	373	152	39	1.6%
Hawaii	145	262	266	126	252	191	195	31	5.1%
Idaho	255	240	459	201	311	174	167	37	-6.8%
Illinois	184	195	169	135	120	143	116	44	-7.4%
Indiana	226	234	242	250	211	286	261	22	2.4%
Iowa	122	164	97	117	119	127	123	43	0.1%
Kansas	244	139	265	168	365	155	240	27	-0.3%
Kentucky	227	283	200	192	194	406	203	30	-1.9%
Louisiana	253	196	312	378	378	276	472	6	11.0%
Maine	16	474	102	535	2,493	665	908	1	95.6%
Maryland	112	236	124	120	116	337	141	42	4.0%
Massachusetts	427	124	91	145	275	813	250	24	-8.5%
Michigan	785	551	350	268	779	443	555	4	-5.6%
Minnesota	359	120	154	302	129	127	150	40	-13.5%
Mississippi	178	184	297	282	557	268	519	5	19.5%
Missouri	304	126	167	204	264	150	255	23	-2.9%
Montana	161	139	287	154	215	143	169	36	0.8%
Nebraska	128	120	87	90	154	188	84	50	-6.8%
Nevada	66	74	107	96	114	126	87	48	4.7%
New Hampshire	189	725	105	192	1,113	509	292	16	7.5%
New Jersey	166	112	261	137	86	510	248	26	6.9%
New Mexico	149	82	122	136	141	138	170	35	2.2%
New York	86	67	87	107	227	406	171	34	12.1%
North Carolina	228	440	210	823	265	1,762	288	18	3.9%
North Dakota	113	81	104	120	87	94	107	45	-0.9%
Ohio	217	170	172	173	248	242	305	13	5.8%
Oklahoma	611	109	824	317	290	176	335	10	-9.5%
Oregon	167	277	200	285	313	113	265	21	8.0%
Pennsylvania	139	400	157	126	177	518	249	25	10.3%
Rhode Island	783	54	342	169	728	595	236	28	-18.1%
South Carolina	111	755	224	1,647	373	470	327	11	19.7%
South Dakota	1,100	107	126	216	95	92	295	15	-19.7%
Tennessee	129	185	219	208	482	200	267	20	13.0%
Texas	182	188	269	211	481	167	291	17	8.1%
Utah	190	187	200	190	139	125	146	41	-4.3%
Vermont	7	741	204	352	874	898	444	7	100.3%
Virginia	449	176	201	237	190	507	310	12	-6.0%
Washington	155	303	550	224	271	270	300	14	11.6%
West Virginia	542	663	815	743	691	740	755	2	5.7%
Wisconsin	143	139	105	136	204	123	356	9	16.4%
Wyoming	369	193	187	193	216	135	164	38	-12.6%

Appendix Table 15: System Average Interruption Duration Index (SAIDI) without Major Event Days in Minutes

	2013	2014	2015	2016	2017	2018	2019	Rank	CAGR
Alabama	114	122	122	115	116	121	120	25	0.9%
Alaska	222	195	162	181	137	193	184	9	-3.0%
Arizona	55	52	55	58	51	61	67	49	3.3%
Arkansas	207	203	213	208	178	210	222	3	1.1%
California	84	86	93	99	103	102	104	33	3.6%
Colorado	82	78	82	82	78	85	84	40	0.3%
Connecticut	55	86	70	92	68	76	200	8	23.9%
Delaware	129	114	115	103	83	74	74	46	-8.8%
District of Columbia	124	82	112	115	58	53	55	51	-12.7%
Florida	74	84	77	82	78	77	74	45	0.0%
Georgia	87	90	106	122	121	123	128	21	6.6%
Hawaii	116	117	117	96	104	152	113	28	-0.4%
Idaho	172	183	263	170	247	145	144	17	-3.0%
Illinois	84	92	89	81	73	73	74	47	-2.1%
Indiana	107	115	120	126	131	142	147	14	5.4%
Iowa	77	93	86	92	95	93	90	38	2.6%
Kansas	111	106	127	132	131	109	117	26	0.9%
Kentucky	146	158	116	137	120	147	149	13	0.3%
Louisiana	98	111	152	179	184	206	208	7	13.3%
Maine	4	83	87	264	238	273	214	5	92.8%
Maryland	111	85	109	105	86	95	91	37	-3.3%
Massachusetts	83	82	74	113	91	99	96	35	2.5%
Michigan	199	179	178	193	179	185	211	6	1.0%
Minnesota	87	75	78	88	73	87	81	41	-1.1%
Mississippi	117	147	187	180	201	212	222	2	11.3%
Missouri	88	90	93	83	96	94	113	29	4.3%
Montana	139	124	141	128	162	118	127	23	-1.5%
Nebraska	54	66	52	54	70	74	62	50	2.5%
Nevada	51	61	55	74	88	77	77	43	7.3%
New Hampshire	123	122	94	141	151	152	217	4	10.0%
New Jersey	123	79	65	86	71	88	87	39	-5.7%
New Mexico	98	75	99	101	111	123	132	19	5.1%
New York	43	46	77	83	72	79	79	42	10.6%
North Carolina	111	118	127	146	146	162	146	16	4.6%
North Dakota	88	78	81	98	64	95	74	44	-2.8%
Ohio	112	130	141	128	143	151	146	15	4.6%
Oklahoma	109	101	177	149	138	127	139	18	4.2%
Oregon	82	106	101	101	111	93	104	34	4.0%
Pennsylvania	99	100	99	101	109	119	128	22	4.3%
Rhode Island	57	54	64	69	59	65	68	48	3.0%
South Carolina	97	97	119	120	118	137	106	32	1.5%
South Dakota	171	100	103	80	76	74	107	30	-7.6%
Tennessee	92	105	121	157	133	139	161	12	9.7%
Texas	105	112	137	129	133	114	122	24	2.4%
Utah	176	148	156	106	115	127	115	27	-6.8%
Vermont	2	212	204	270	247	262	170	11	109.7%
Virginia	135	141	146	163	140	188	182	10	5.1%
Washington	97	115	110	111	132	115	106	31	1.4%
West Virginia	418	450	458	439	452	513	471	1	2.0%
Wisconsin	75	71	69	77	78	79	93	36	3.6%
Wyoming	169	178	166	150	191	118	130	20	-4.3%

Appendix Table 16: System Average Interruption Frequency Index (SAIFI) with Major Event Days in Minutes

	2013	2014	2015	2016	2017	2018	2019	Rank	CAGR
Alabama	3.15	3.20	1.71	1.57	1.97	1.52	1.41	22	-12.5%
Alaska	6.12	2.38	2.56	2.30	1.71	3.14	2.19	3	-15.7%
Arizona	0.83	0.85	2.92	0.84	0.89	0.94	0.89	46	1.2%
Arkansas	1.78	1.78	1.98	2.03	2.05	1.77	1.93	9	1.4%
California	0.87	0.93	0.92	1.03	1.28	0.95	1.26	29	6.5%
Colorado	1.08	0.90	1.01	1.14	1.19	0.97	1.08	37	-0.1%
Connecticut	0.69	0.74	0.70	1.06	0.95	1.25	0.97	44	5.9%
Delaware	1.46	1.42	1.52	1.35	1.13	1.03	0.98	43	-6.5%
District of Columbia	0.88	0.69	0.69	0.82	0.55	0.64	0.59	51	-6.4%
Florida	1.12	1.18	1.12	1.37	2.01	1.13	1.03	39	-1.5%
Georgia	1.34	1.50	1.53	1.51	2.43	1.56	1.38	24	0.5%
Hawaii	2.13	2.31	2.99	1.89	2.09	1.96	2.05	7	-0.6%
Idaho	1.64	1.28	1.75	1.38	1.72	1.20	1.24	30	-4.6%
Illinois	1.11	1.13	1.11	1.02	0.93	0.92	0.93	45	-2.9%
Indiana	1.20	1.26	1.26	1.30	1.26	1.46	1.50	16	3.8%
Iowa	0.97	1.20	0.96	1.05	1.00	1.01	1.08	36	1.9%
Kansas	1.57	1.35	2.26	1.41	1.48	1.17	1.37	25	-2.3%
Kentucky	1.81	1.91	1.34	1.46	1.35	1.78	1.61	12	-1.9%
Louisiana	2.44	2.35	2.27	2.12	2.29	2.10	2.17	4	-2.0%
Maine	2.89	10.92	1.87	2.69	3.07	2.80	2.53	2	-2.2%
Maryland	4.15	1.26	1.09	1.09	0.97	1.30	1.05	38	-20.5%
Massachusetts	1.13	0.96	0.79	0.99	1.09	1.55	1.22	31	1.4%
Michigan	1.52	2.55	2.22	1.15	1.41	1.37	1.53	14	0.1%
Minnesota	1.65	1.44	0.97	1.21	0.94	1.02	0.99	42	-8.1%
Mississippi	1.45	1.51	1.85	1.93	2.19	1.76	2.10	6	6.3%
Missouri	1.12	1.09	1.06	1.04	1.19	0.97	1.30	28	2.5%
Montana	1.36	1.13	1.75	1.26	1.58	1.28	1.33	26	-0.5%
Nebraska	0.99	1.28	0.71	0.67	0.88	1.09	0.65	50	-6.6%
Nevada	0.72	0.70	0.73	0.84	0.90	0.98	0.81	49	2.1%
New Hampshire	2.17	2.26	1.38	1.54	2.30	2.17	1.43	21	-6.7%
New Jersey	1.34	0.95	0.99	1.15	0.93	1.42	1.19	33	-2.0%
New Mexico	1.06	0.85	3.38	1.75	1.29	1.15	1.20	32	2.0%
New York	0.65	0.69	0.67	0.78	0.84	1.01	0.88	47	5.0%
North Carolina	2.20	1.49	1.34	1.79	1.33	2.17	1.44	20	-6.9%
North Dakota	0.87	0.88	1.08	0.96	0.88	0.91	0.87	48	0.1%
Ohio	1.18	1.22	1.21	1.18	1.35	1.41	1.47	19	3.8%
Oklahoma	1.82	1.05	1.67	1.58	1.43	1.33	1.53	15	-2.9%
Oregon	0.79	1.29	1.21	1.31	1.41	0.92	1.00	41	4.0%
Pennsylvania	0.97	1.22	0.99	1.07	1.11	1.43	1.31	27	5.1%
Rhode Island	1.26	0.76	1.23	1.21	1.19	1.57	1.40	23	1.7%
South Carolina	1.80	1.82	1.44	2.39	1.59	1.75	1.48	18	-3.1%
South Dakota	1.84	0.92	0.97	1.16	1.06	1.08	1.58	13	-2.5%
Tennessee	2.98	1.75	1.98	2.05	1.77	1.90	2.15	5	-5.3%
Texas	1.54	1.43	2.05	1.60	1.67	1.39	1.67	11	1.4%
Utah	1.65	1.36	1.43	1.31	1.06	1.02	1.00	40	-8.0%
Vermont	2.22	2.20	1.67	1.86	2.41	2.62	1.98	8	-1.9%
Virginia	2.89	1.37	1.41	1.53	1.36	1.82	1.73	10	-8.2%
Washington	1.05	1.52	1.70	1.17	1.32	1.21	1.17	34	1.8%
West Virginia	2.29	2.37	2.42	2.35	2.33	2.65	2.80	1	3.4%
Wisconsin	0.77	0.83	1.32	0.97	0.91	0.81	1.09	35	6.0%
Wyoming	1.79	1.47	1.46	1.49	1.66	1.27	1.49	17	-3.0%

Appendix Table 17: System Average Interruption Frequency Index (SAIFI) without Major Event Days in Minutes

	2013	2014	2015	2016	2017	2018	2019	Rank	CAGR
Alabama	2.883	2.917	1.240	1.164	1.079	1.177	1.100	23	-14.8%
Alaska	2.307	2.029	1.834	1.926	1.826	2.603	1.588	6	-6.0%
Arizona	0.633	0.592	1.280	0.608	0.575	0.611	0.775	44	3.4%
Arkansas	1.566	1.551	1.752	1.677	1.454	1.483	1.508	7	-0.6%
California	0.816	0.849	0.831	0.934	0.897	0.852	0.877	37	1.2%
Colorado	1.000	0.883	0.904	0.909	0.875	0.897	0.858	39	-2.5%
Connecticut	0.588	0.742	0.647	0.906	0.682	0.705	0.877	36	6.9%
Delaware	1.280	1.179	1.292	1.156	0.992	0.856	0.860	38	-6.4%
District of Columbia	0.880	0.640	0.686	0.820	0.553	0.538	0.490	51	-9.3%
Florida	1.033	1.114	1.050	1.066	1.038	0.970	0.938	34	-1.6%
Georgia	1.160	1.142	1.258	1.337	1.185	1.257	1.241	14	1.1%
Hawaii	1.605	1.845	1.711	1.336	1.198	1.688	1.192	15	-4.8%
Idaho	1.395	1.145	1.433	1.214	1.646	1.094	1.144	19	-3.3%
Illinois	0.852	0.948	0.940	0.831	0.754	0.779	0.763	46	-1.8%
Indiana	0.960	1.020	1.016	1.032	1.005	1.131	1.172	16	3.4%
Iowa	0.854	0.987	0.924	0.937	0.907	0.938	0.947	31	1.7%
Kansas	1.246	1.203	1.747	1.231	1.188	0.988	1.034	26	-3.1%
Kentucky	1.446	1.502	1.125	1.257	1.096	1.270	1.383	9	-0.7%
Louisiana	1.431	1.529	1.805	1.773	1.713	1.840	1.654	4	2.4%
Maine	1.976	2.464	1.818	2.166	2.182	2.038	1.679	3	-2.7%
Maryland	4.369	0.998	1.044	1.022	0.863	0.965	0.879	35	-23.5%
Massachusetts	0.891	0.827	0.739	0.910	0.578	0.917	0.842	40	-0.9%
Michigan	0.919	0.890	0.965	1.011	0.989	1.055	1.162	17	4.0%
Minnesota	1.300	1.271	0.811	0.858	0.759	0.882	0.802	42	-7.7%
Mississippi	1.234	1.292	1.585	1.719	1.559	1.633	1.623	5	4.7%
Missouri	0.818	0.929	0.922	0.770	0.825	0.839	1.018	29	3.7%
Montana	1.274	1.128	1.446	1.136	1.362	1.183	1.243	13	-0.4%
Nebraska	0.518	0.690	0.546	0.538	0.672	0.708	0.547	50	0.9%
Nevada	0.572	0.632	0.557	0.735	0.811	0.813	0.773	45	5.1%
New Hampshire	1.301	1.582	1.353	1.382	1.534	1.268	1.249	12	-0.7%
New Jersey	1.219	0.868	0.833	0.980	0.875	0.964	0.942	32	-4.2%
New Mexico	0.939	0.821	1.559	1.394	1.083	1.090	1.083	25	2.4%
New York	0.589	0.608	0.645	0.696	0.620	0.648	0.635	49	1.3%
North Carolina	1.887	1.032	1.111	1.133	1.132	1.150	1.106	22	-8.5%
North Dakota	0.944	1.032	0.920	0.967	0.756	0.888	0.819	41	-2.3%
Ohio	0.950	1.108	1.139	1.064	1.135	1.174	1.136	20	3.0%
Oklahoma	1.031	0.998	1.115	1.256	1.121	1.134	1.149	18	1.8%
Oregon	0.649	0.864	0.713	0.776	0.866	0.804	0.745	48	2.3%
Pennsylvania	0.905	0.919	0.891	0.960	0.938	1.022	1.026	27	2.1%
Rhode Island	0.720	0.762	0.937	0.973	0.775	1.001	1.024	28	6.0%
South Carolina	1.725	1.111	1.154	1.214	1.114	1.223	1.004	30	-8.6%
South Dakota	1.063	0.687	0.850	0.895	0.967	0.913	1.094	24	0.5%
Tennessee	2.766	1.460	1.688	1.877	1.427	1.689	1.794	2	-7.0%
Texas	1.203	1.164	1.438	1.263	1.277	1.089	1.118	21	-1.2%
Utah	1.290	1.192	1.261	0.965	0.945	1.017	0.941	33	-5.1%
Vermont	1.948	1.504	1.752	1.837	1.899	1.926	1.465	8	-4.6%
Virginia	1.197	1.207	1.230	1.334	1.160	1.389	1.342	10	1.9%
Washington	0.809	0.977	0.844	0.789	0.943	0.830	0.779	43	-0.6%
West Virginia	1.709	2.132	2.150	2.104	2.057	2.352	2.352	1	5.5%
Wisconsin	0.659	0.672	1.072	0.705	0.618	0.698	0.755	47	2.3%
Wyoming	1.558	1.468	1.422	1.357	1.615	1.190	1.285	11	-3.2%

Appendix Table 18: Customer Average Interruption Duration Index (CAIDI) with Major Event Days in Minutes

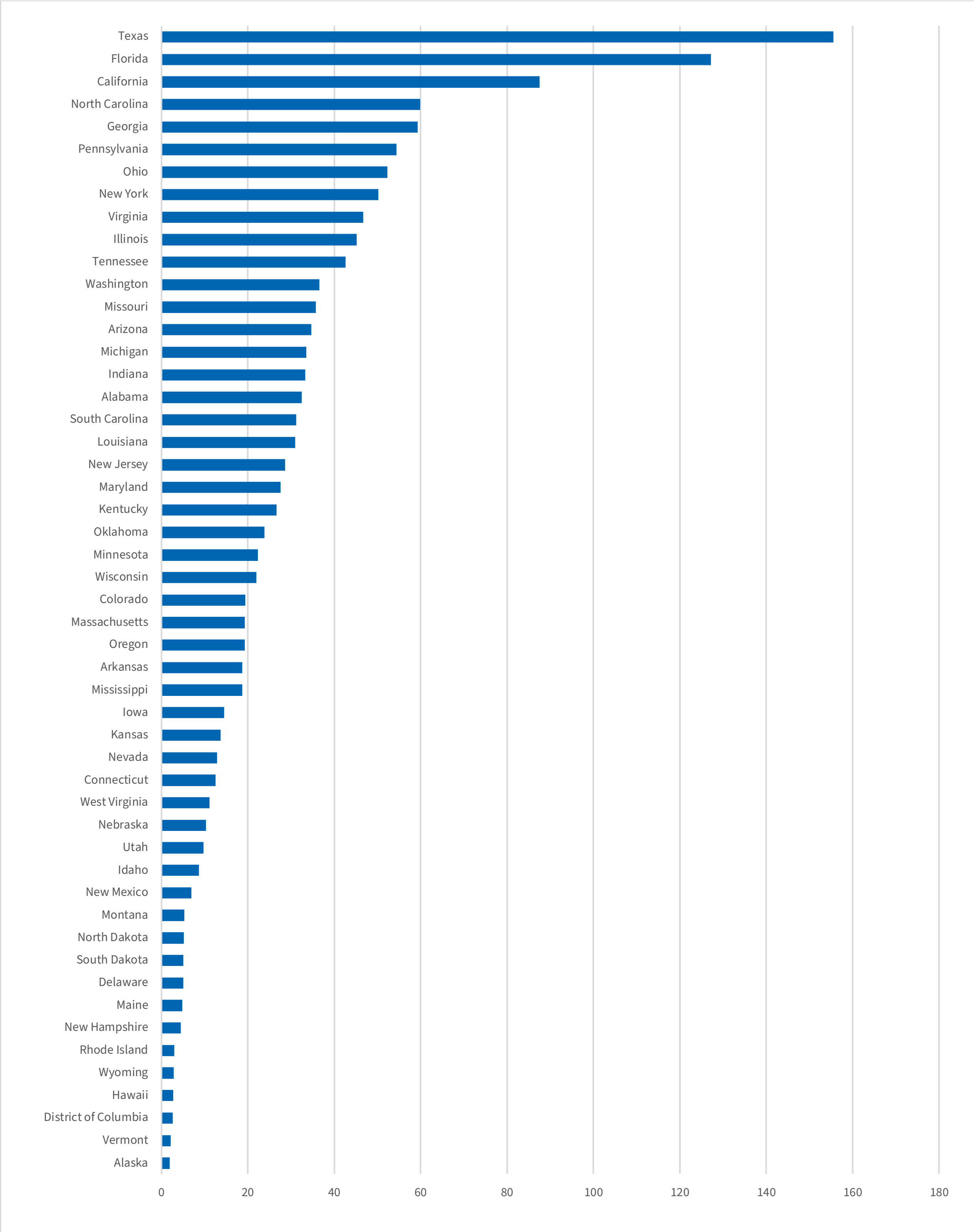
	2013	2014	2015	2016	2017	2018	2019	Rank	CAGR
Alabama	163	132	120	109	158	187	122	40	-4.6%
Alaska	151	111	207	83	104	117	138	30	-1.5%
Arizona	87	103	289	99	98	111	92	50	1.0%
Arkansas	160	150	158	198	189	179	220	11	5.4%
California	116	110	125	115	173	189	371	1	21.4%
Colorado	270	87	104	128	138	104	175	23	-7.0%
Connecticut	115	117	149	169	298	515	243	6	13.3%
Delaware	110	127	128	115	145	143	109	46	-0.1%
District of Columbia	141	139	164	140	104	170	131	33	-1.3%
Florida	78	81	77	254	1,157	167	85	51	1.5%
Georgia	102	135	137	245	442	150	105	47	0.4%
Hawaii	79	91	89	74	115	95	116	43	6.7%
Idaho	137	128	178	138	150	139	123	39	-1.9%
Illinois	237	181	152	151	128	155	122	41	-10.5%
Indiana	192	283	289	319	161	188	171	26	-2.0%
Iowa	130	137	98	110	117	124	114	45	-2.2%
Kansas	162	104	163	116	209	124	182	22	1.9%
Kentucky	107	127	123	123	133	242	118	42	1.7%
Louisiana	91	71	146	178	161	131	223	9	16.0%
Maine	5	114	43	194	861	240	366	2	103.0%
Maryland	94	187	114	110	115	259	127	35	5.1%
Massachusetts	371	125	111	145	248	519	208	13	-9.2%
Michigan	511	450	296	234	559	319	356	3	-5.9%
Minnesota	320	115	162	201	151	118	134	32	-13.5%
Mississippi	105	85	147	135	210	131	208	14	12.0%
Missouri	265	130	156	183	215	149	189	21	-5.5%
Montana	121	120	172	117	125	102	114	44	-1.0%
Nebraska	168	198	204	218	161	163	123	38	-5.1%
Nevada	110	94	122	104	125	144	97	49	-2.1%
New Hampshire	95	376	95	125	475	237	194	19	12.5%
New Jersey	125	115	183	109	87	297	172	24	5.4%
New Mexico	142	89	113	86	96	109	129	34	-1.5%
New York	147	138	155	145	229	609	197	17	5.0%
North Carolina	171	509	202	364	189	687	195	18	2.2%
North Dakota	146	112	101	109	94	99	124	36	-2.7%
Ohio	184	138	137	141	184	169	206	15	1.9%
Oklahoma	443	221	869	205	189	138	240	7	-9.7%
Oregon	237	208	195	271	245	137	213	12	-1.7%
Pennsylvania	140	294	157	117	153	352	189	20	5.1%
Rhode Island	622	71	278	140	615	379	169	27	-19.5%
South Carolina	110	295	205	1,183	217	264	204	16	10.8%
South Dakota	566	167	635	243	94	93	165	28	-18.6%
Tennessee	85	177	108	109	255	106	123	37	6.3%
Texas	120	120	166	122	236	110	159	29	4.8%
Utah	133	136	142	149	126	120	137	31	0.5%
Vermont	3	333	117	183	347	325	220	10	99.9%
Virginia	256	123	138	148	137	244	172	25	-6.4%
Washington	143	189	300	175	191	204	232	8	8.4%
West Virginia	232	279	321	300	280	270	275	5	2.8%
Wisconsin	200	170	102	151	200	150	285	4	6.0%
Wyoming	186	132	125	124	110	101	103	48	-9.3%

Appendix Table 19: Customer Average Interruption Duration Index (CAIDI) without Major Event Days in Minutes

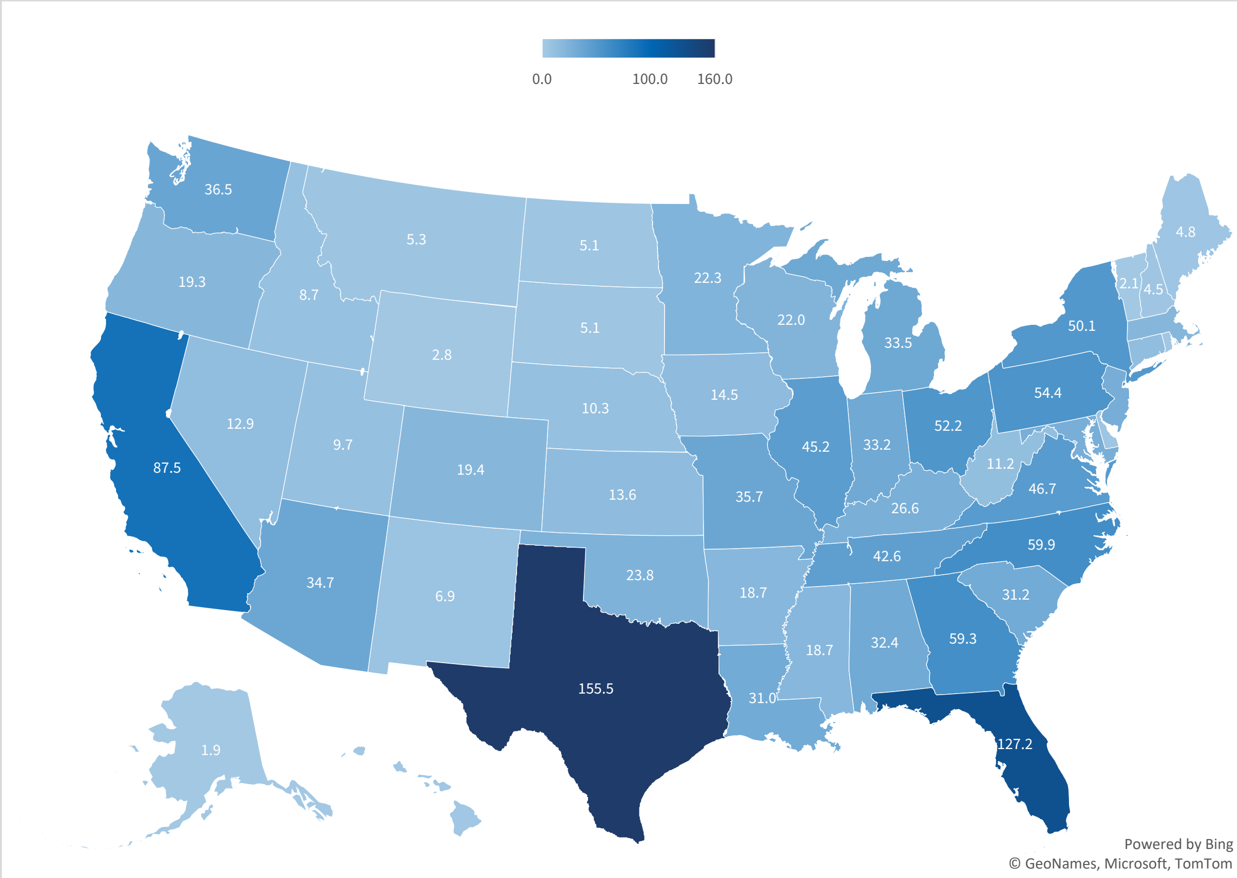
	2013	2014	2015	2016	2017	2018	2019	Rank	CAGR
Alabama	97	107	96	98	108	101	106	28	1.5%
Alaska	100	106	95	88	81	80	129	13	4.4%
Arizona	122	91	83	95	98	86	95	40	-4.0%
Arkansas	128	159	122	123	121	135	144	6	2.0%
California	106	102	112	109	111	110	118	20	1.7%
Colorado	219	83	90	88	88	93	101	32	-12.1%
Connecticut	105	117	107	108	100	107	211	1	12.4%
Delaware	101	100	90	94	88	93	90	48	-1.9%
District of Columbia	141	128	164	140	104	98	112	26	-3.7%
Florida	78	91	75	79	79	80	81	50	0.5%
Georgia	75	76	80	86	95	93	99	38	4.7%
Hawaii	80	67	70	78	86	90	99	35	3.7%
Idaho	113	116	135	137	140	128	112	25	0.0%
Illinois	147	99	103	120	95	92	93	43	-7.3%
Indiana	108	207	118	154	123	121	123	17	2.2%
Iowa	99	96	92	98	104	99	95	41	-0.7%
Kansas	89	89	96	104	99	98	101	31	2.1%
Kentucky	94	95	90	103	101	109	100	34	1.0%
Louisiana	79	82	87	101	107	112	131	12	8.6%
Maine	2	29	39	119	110	133	129	14	98.5%
Maryland	93	86	104	103	100	98	101	33	1.4%
Massachusetts	93	100	102	124	501	109	114	24	3.4%
Michigan	222	207	185	192	181	175	182	3	-3.2%
Minnesota	112	88	97	103	98	97	99	36	-2.0%
Mississippi	88	98	111	105	109	121	129	15	6.7%
Missouri	112	121	128	106	115	107	108	27	-0.7%
Montana	111	107	97	107	114	99	99	37	-1.8%
Nebraska	123	137	149	174	98	95	106	29	-2.5%
Nevada	90	89	93	94	99	94	93	44	0.5%
New Hampshire	114	89	87	102	103	116	173	4	7.2%
New Jersey	102	85	74	82	77	86	85	49	-2.9%
New Mexico	103	88	107	89	98	107	115	23	1.9%
New York	105	120	148	129	134	137	145	5	5.5%
North Carolina	109	320	164	127	127	140	131	10	3.0%
North Dakota	92	79	94	92	77	103	91	46	-0.2%
Ohio	114	119	121	119	122	124	124	16	1.4%
Oklahoma	116	225	301	121	125	116	131	11	2.1%
Oregon	125	124	142	136	141	130	139	7	1.8%
Pennsylvania	109	108	108	104	116	114	121	19	1.8%
Rhode Island	80	71	69	71	76	65	67	51	-2.9%
South Carolina	100	89	132	132	102	111	103	30	0.5%
South Dakota	157	331	577	105	83	93	91	47	-8.7%
Tennessee	70	150	80	93	104	85	94	42	5.1%
Texas	80	89	111	97	97	95	98	39	3.4%
Utah	138	124	128	110	120	121	115	22	-2.9%
Vermont	1	139	117	149	129	137	116	21	120.2%
Virginia	106	109	113	118	117	129	131	9	3.6%
Washington	119	120	127	133	138	132	133	8	1.9%
West Virginia	234	204	204	201	211	210	196	2	-2.9%
Wisconsin	123	106	79	112	121	113	122	18	-0.1%
Wyoming	101	120	116	96	102	86	93	45	-1.4%

Appendix C: Non-Transportation Energy Usage by State

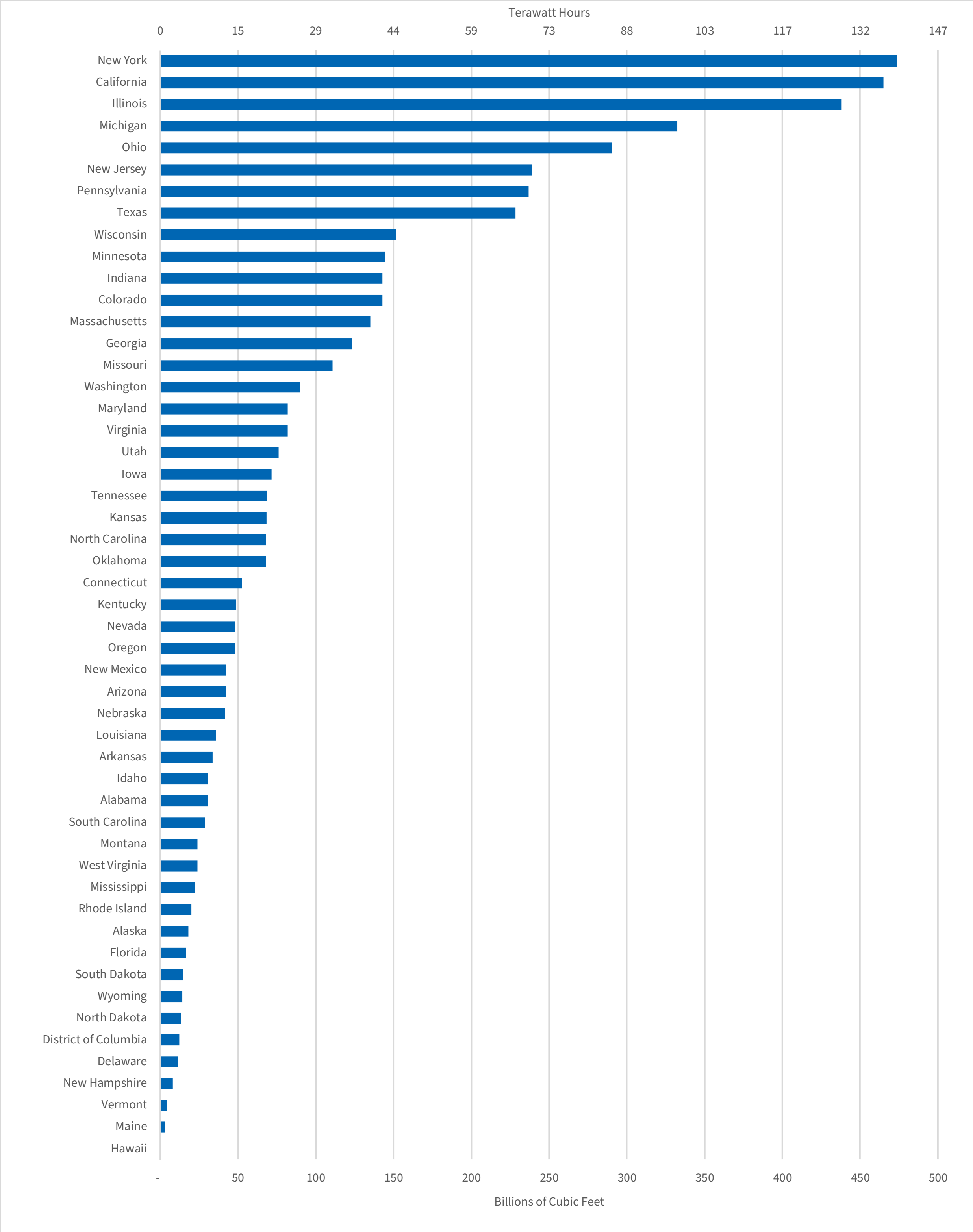
Appendix Figure 1: 2019 Electricity in Residential Sector in Terawatt Hours



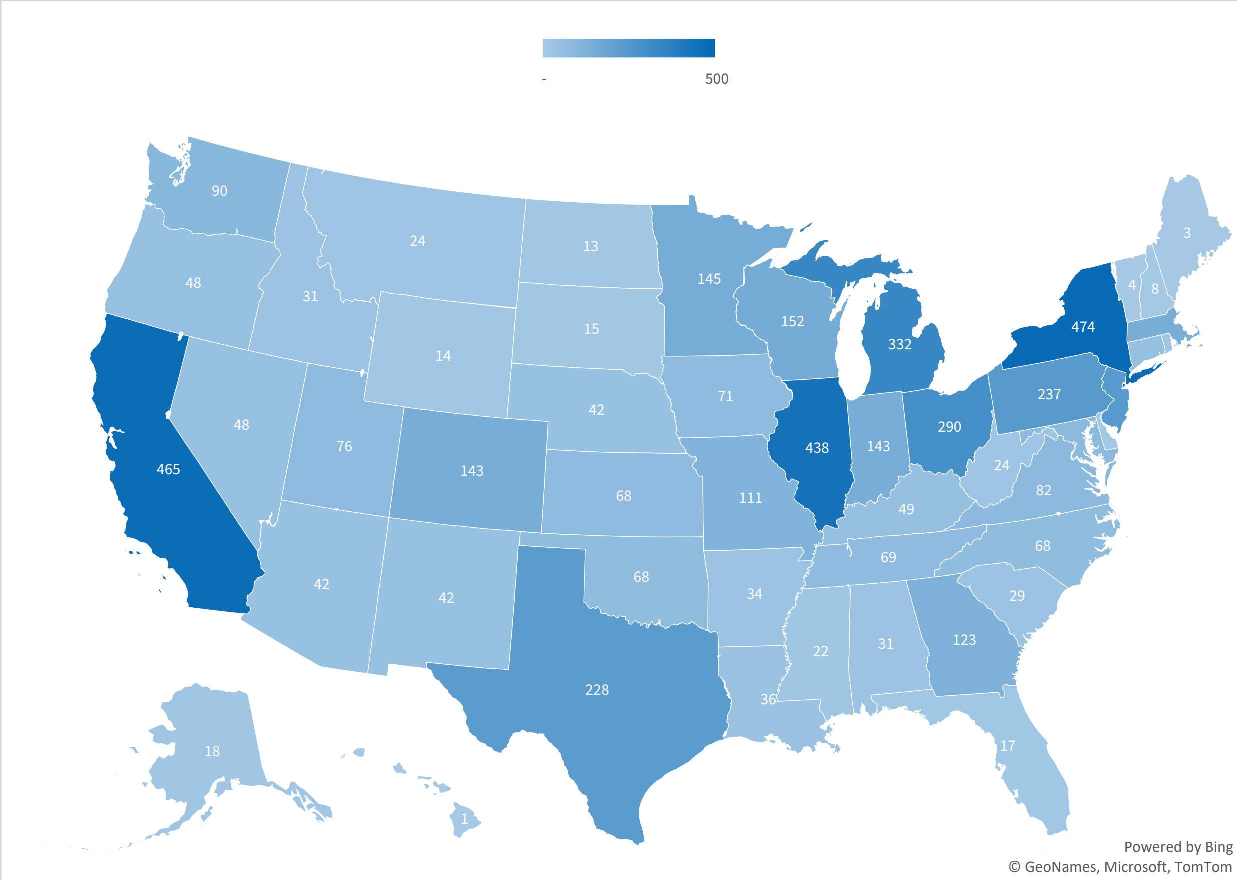
Appendix Figure 2: 2019 Electricity Used in the Residential Sector in Terawatt Hours



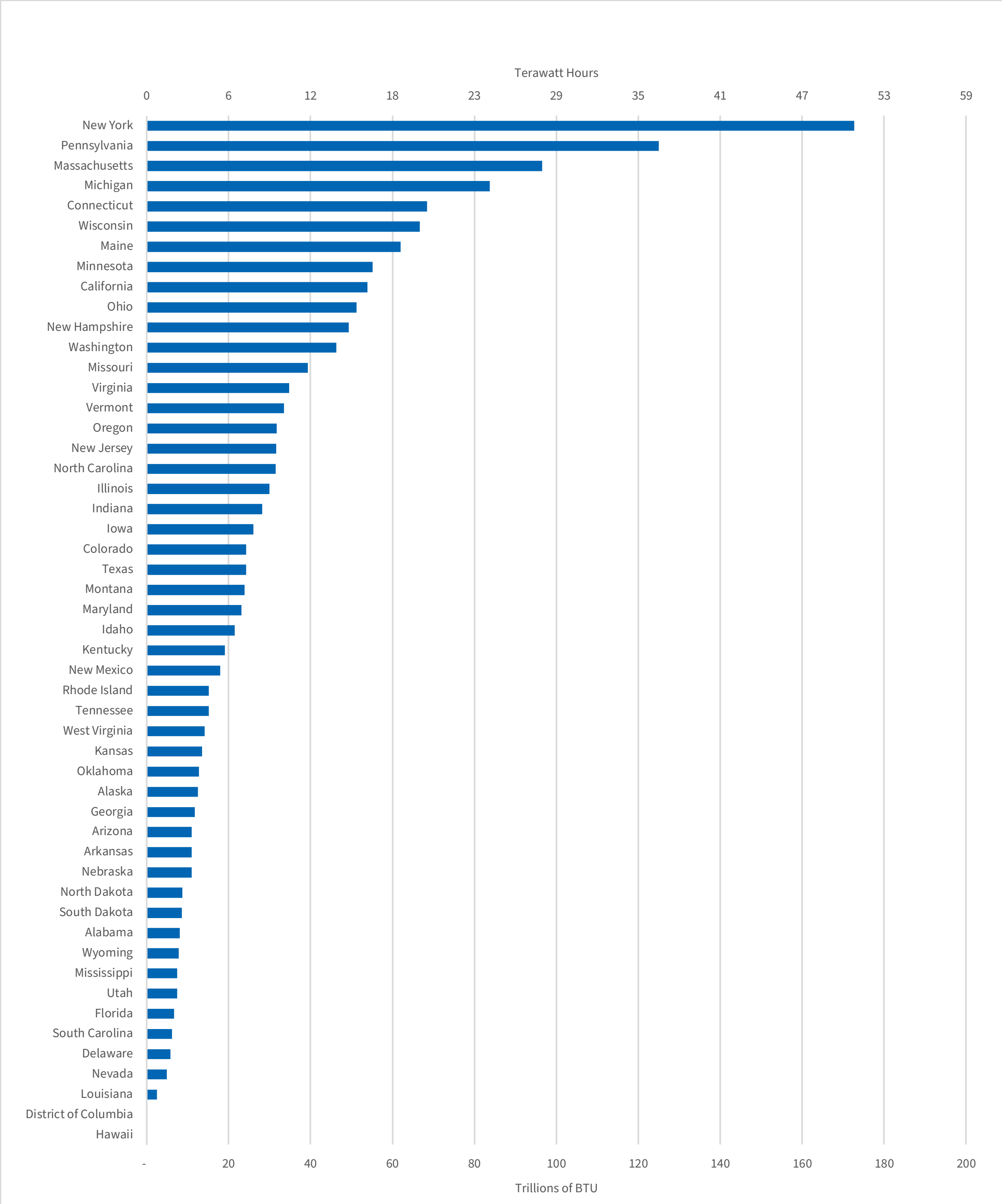
Appendix Figure 3: 2019 Natural Gas Consumed by the Residential Sector



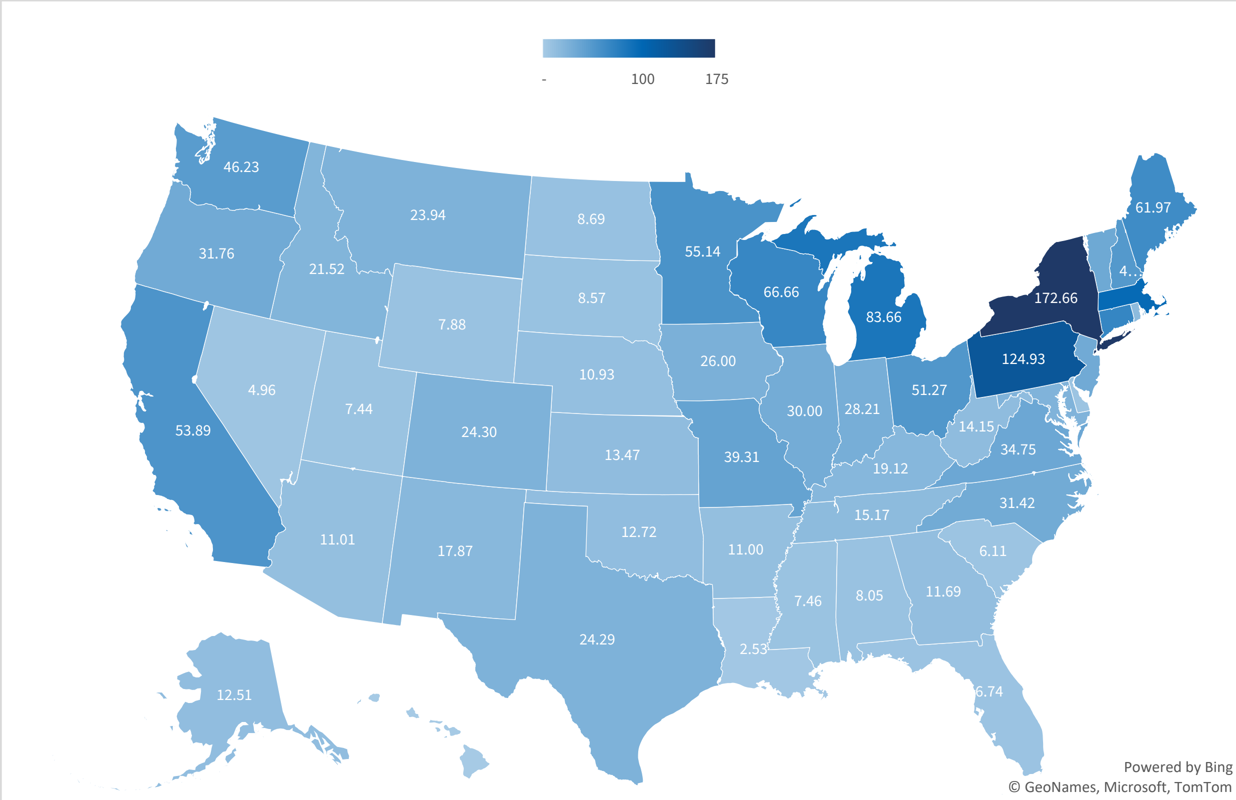
Appendix Figure 4: 2019 Natural Gas Consumed by the Residential Sector in Billions of Cubic Feet



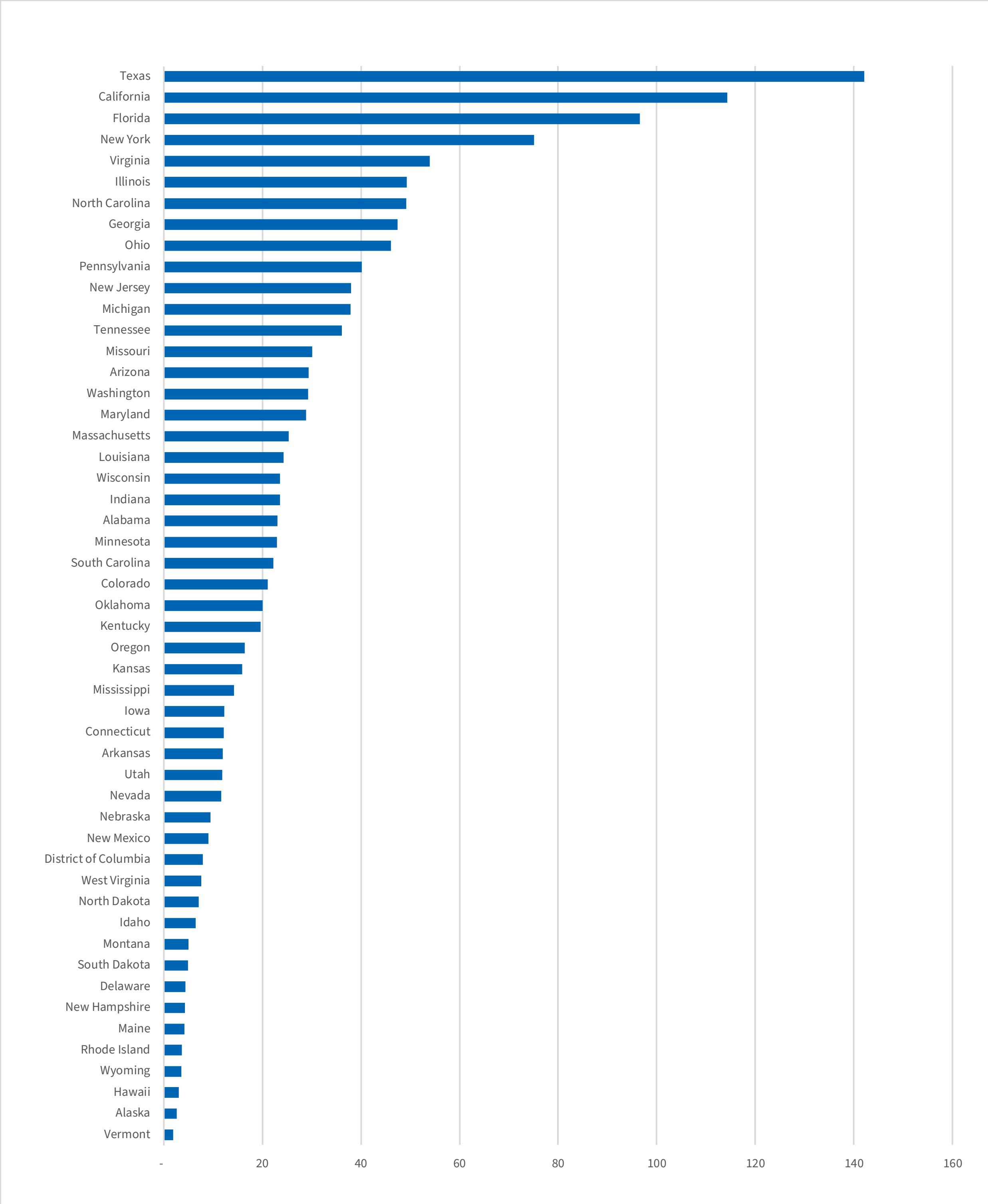
Appendix Figure 5: 2019 Other Heating Fuel Use by the Residential Sector



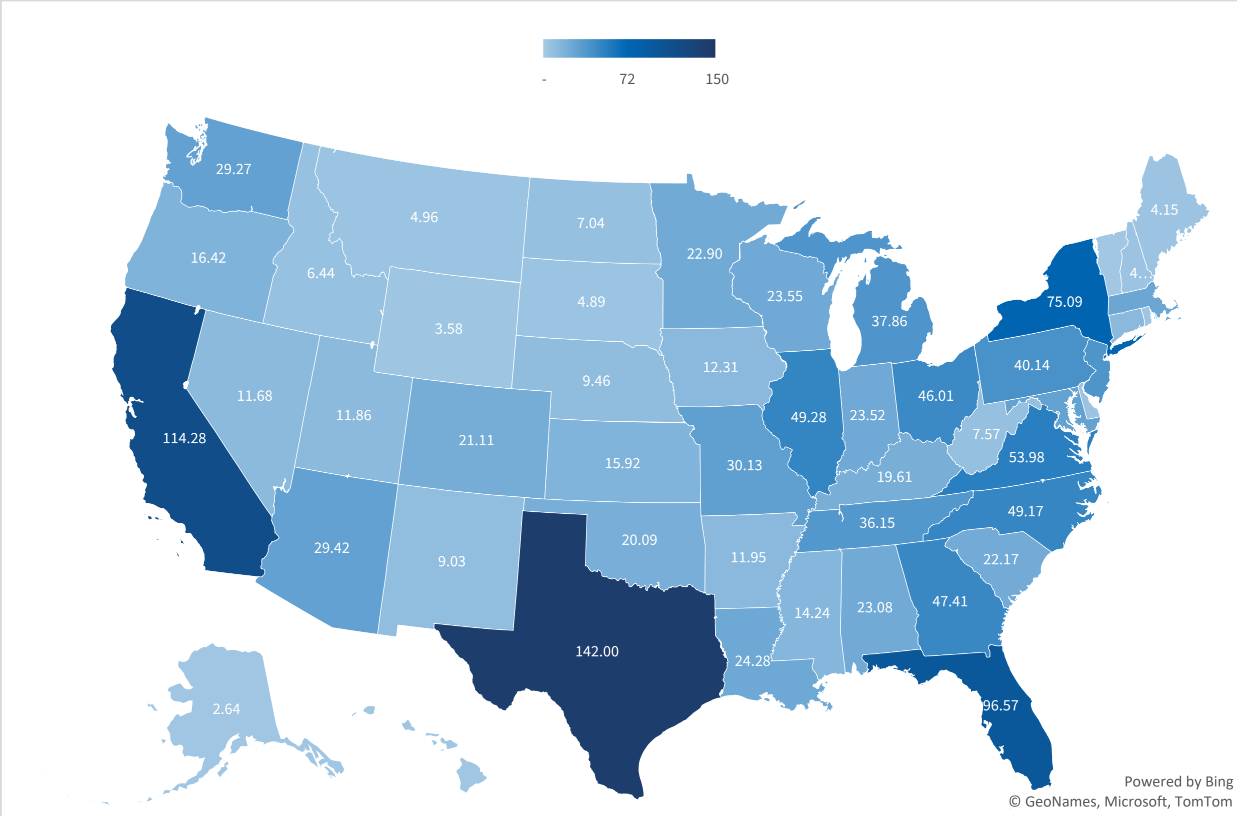
Appendix Figure 6:2019 Other Heating Fuel Use by the Residential Sector in Trillions of BTU



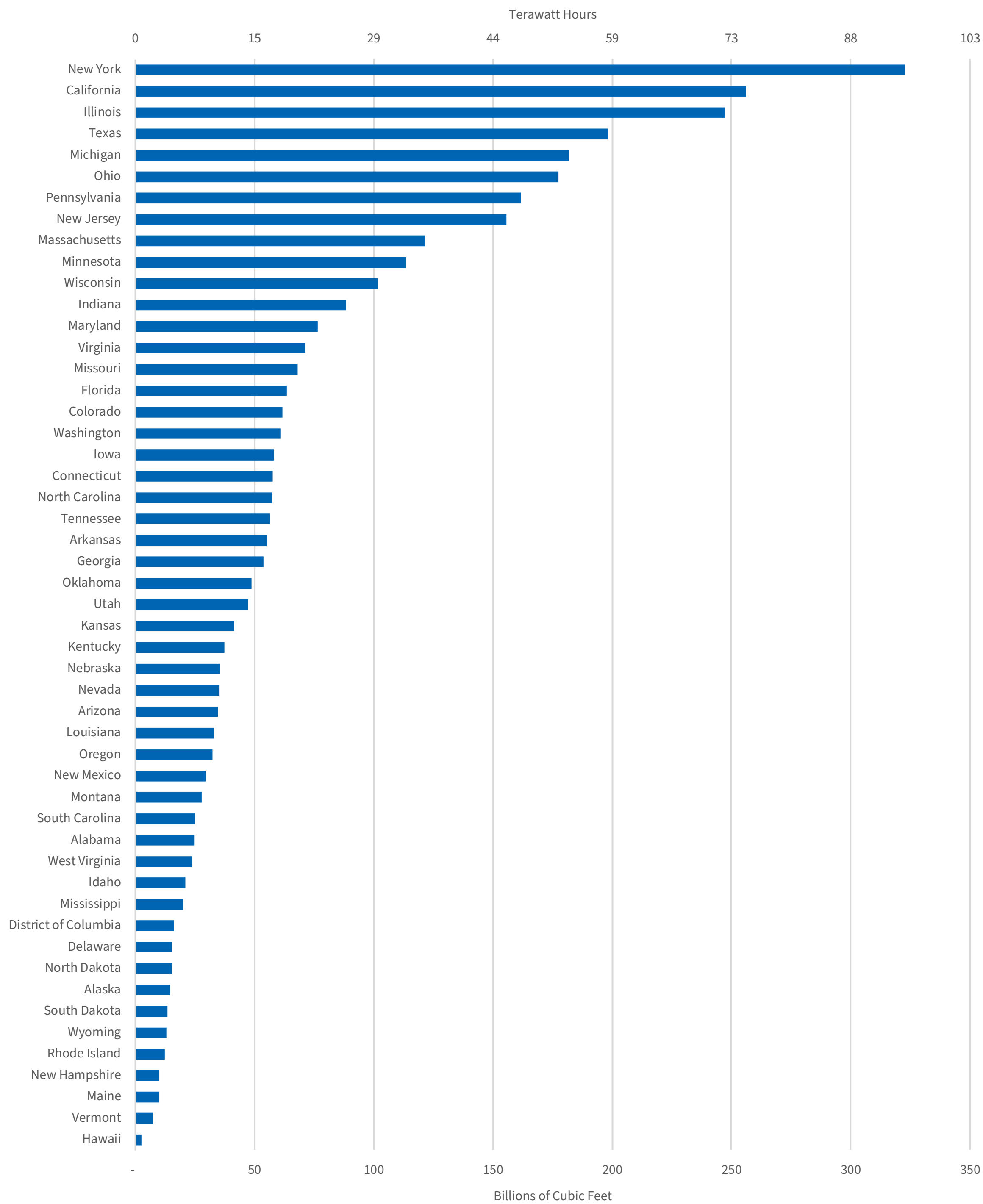
Appendix Figure 7: 2019 Electricity Used in Commercial Sector in Terawatt Hours



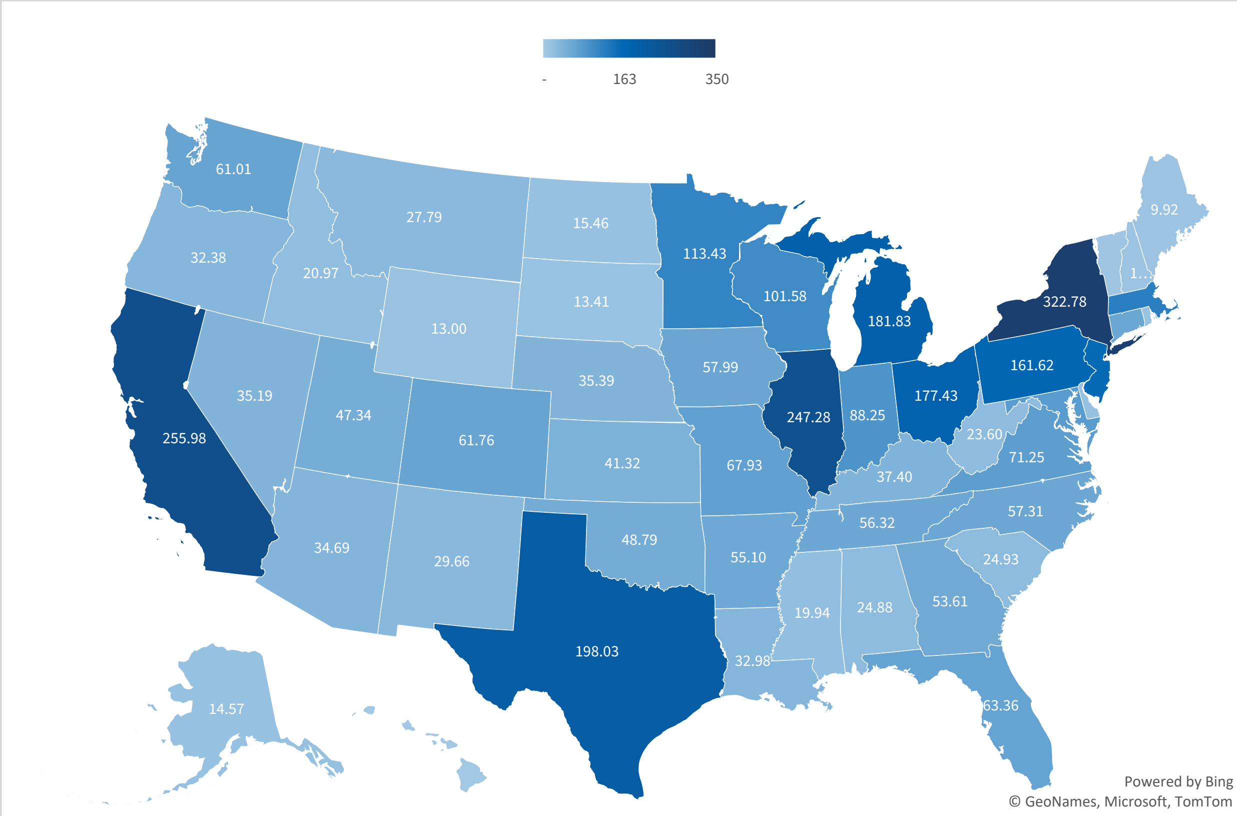
Appendix Figure 8: 2019 Electricity Used in Commercial Sector in Terawatt Hours



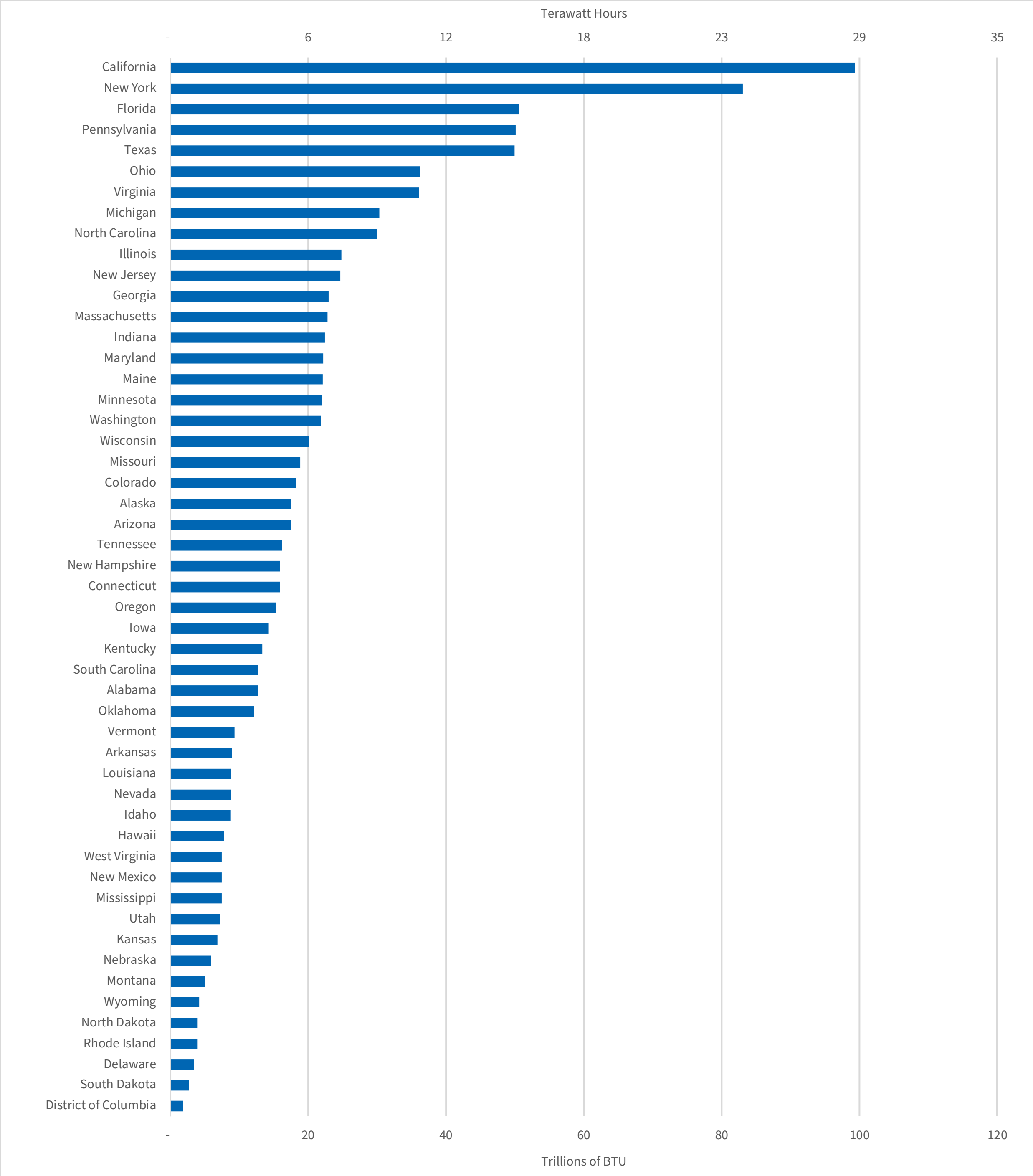
Appendix Figure 9: 2019 Natural Gas Consumed by the Commercial Sector



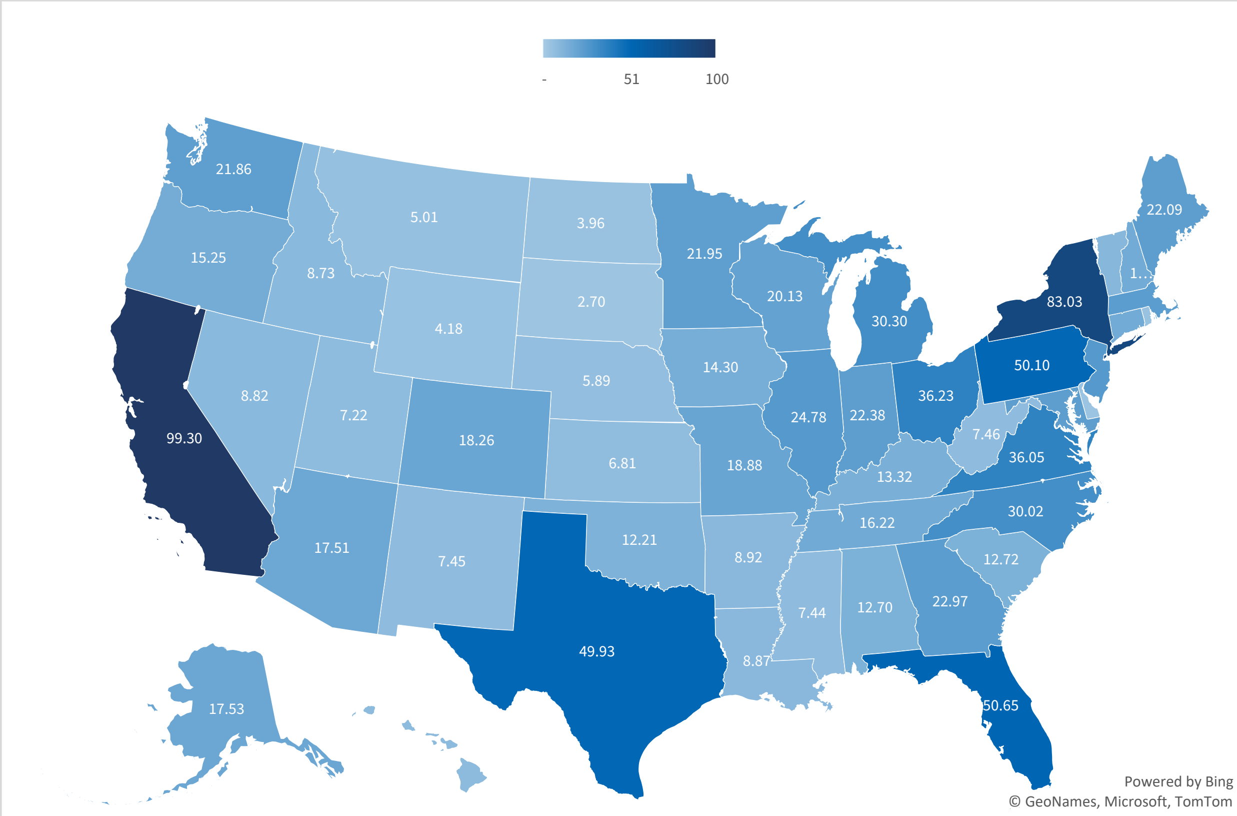
Appendix Figure 10: 2019 Natural Gas Consumed by the Commercial Sector in Billions of Cubic Feet



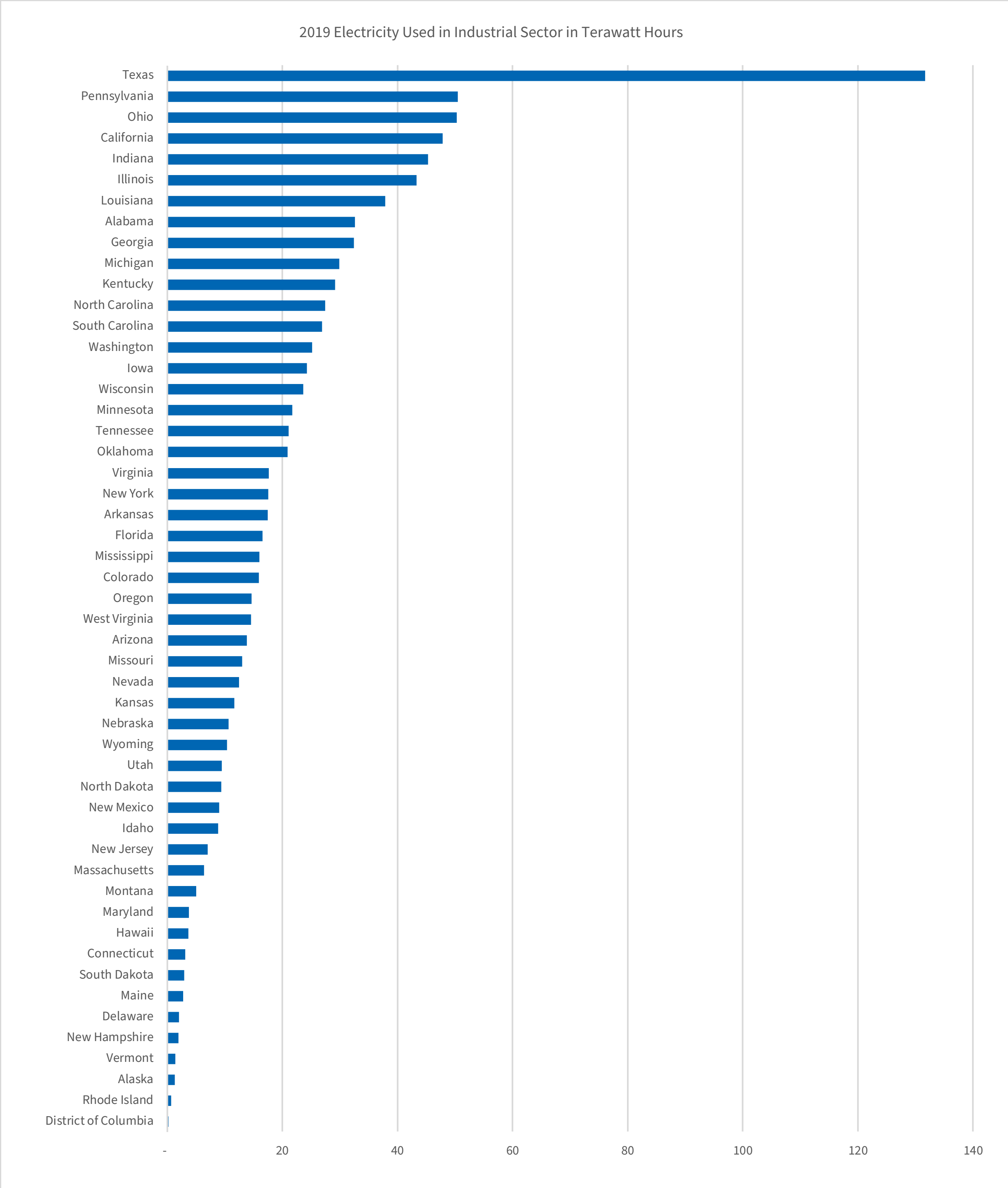
Appendix Figure 11: 2019 Other Heating Fuel Use by the Commercial Sector



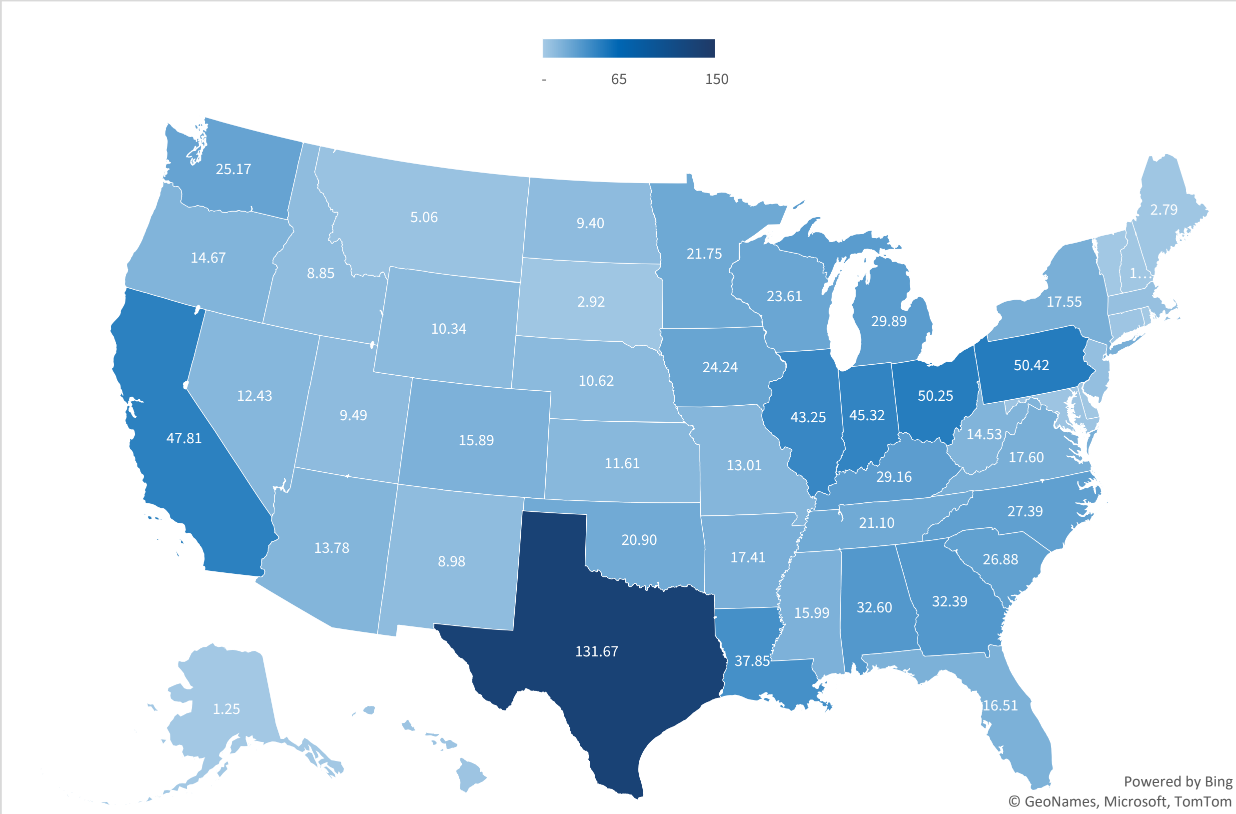
Appendix Figure 12: 2019 Other Heating Fuel Use by the Commercial Sector in Trillions of BTU



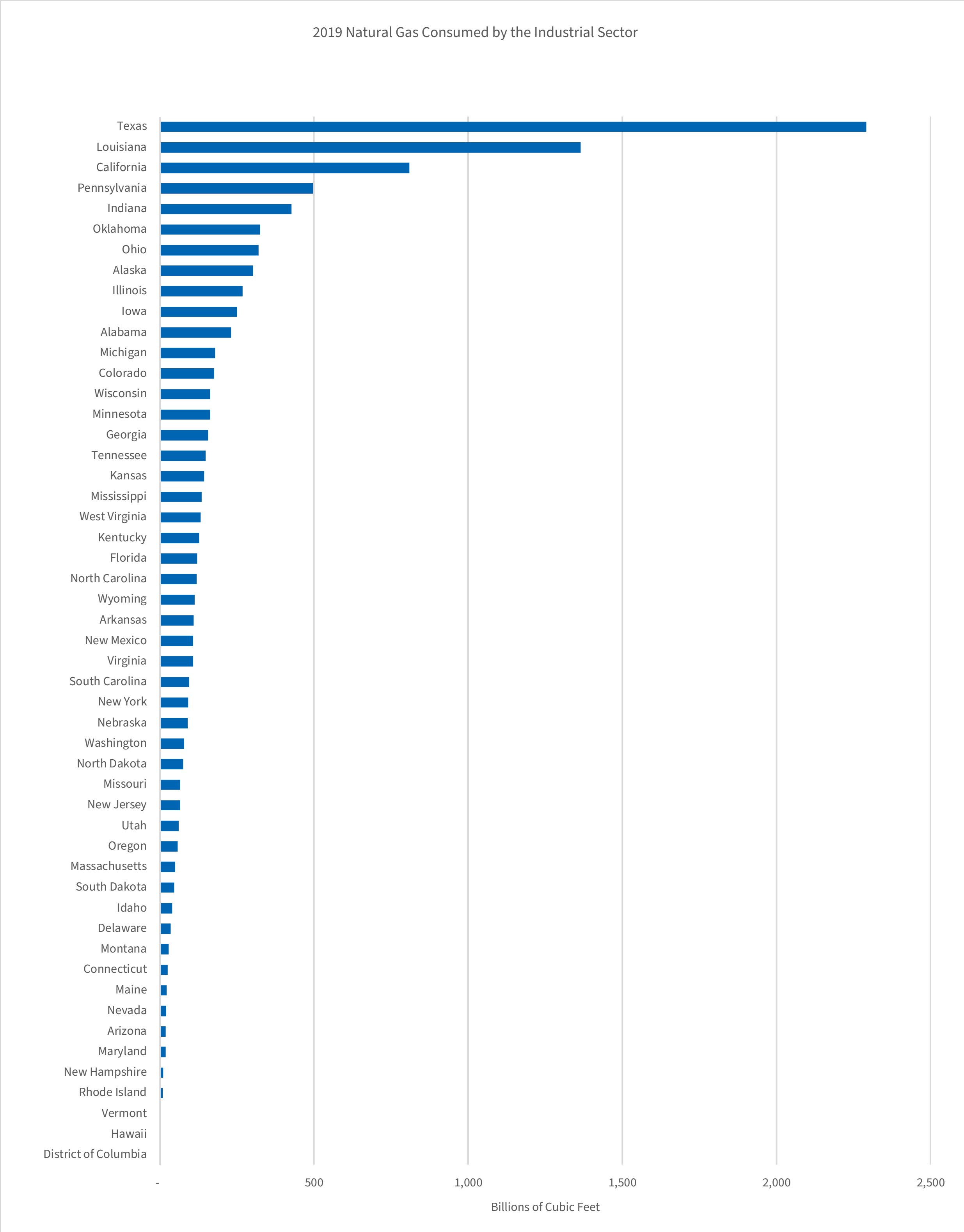
Appendix Figure 13: 2019 Electricity Used in Industrial Sector in Terawatt Hours



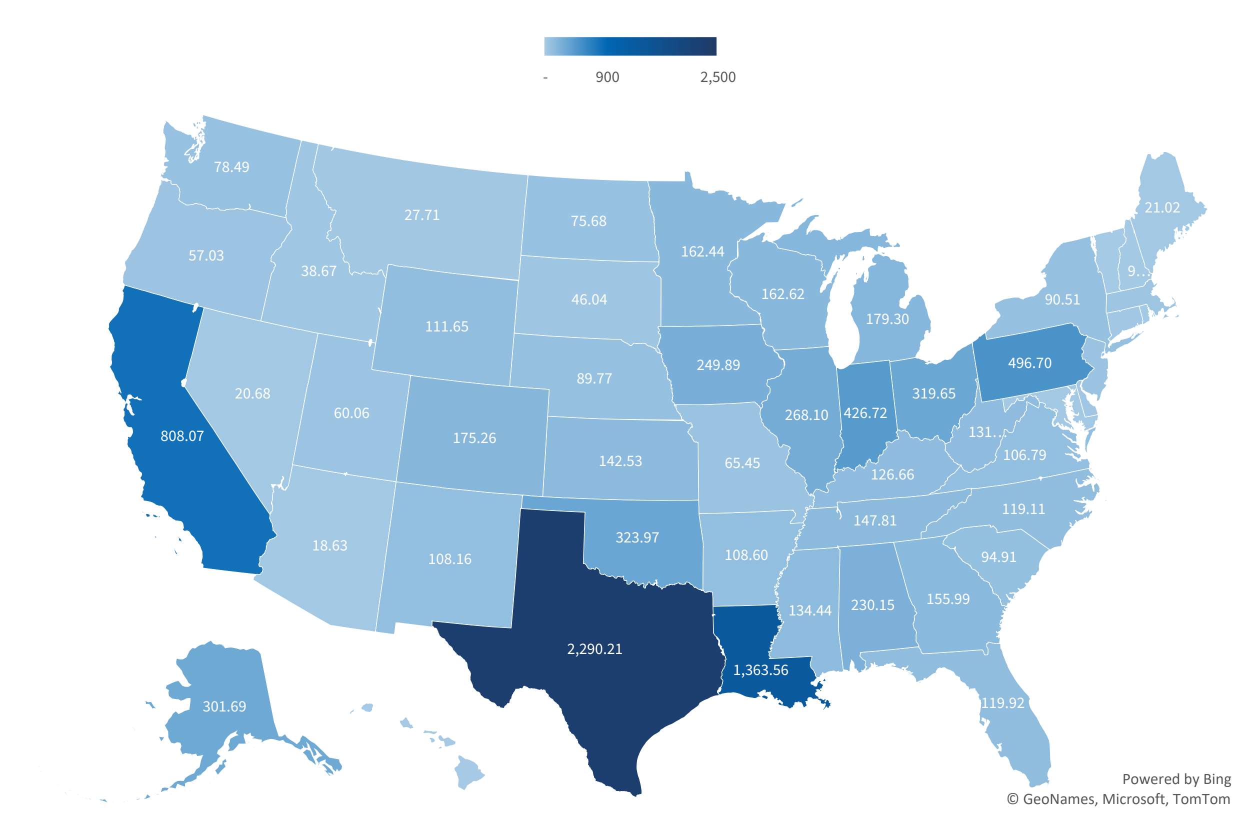
Appendix Figure 14: 2019 Electricity Used in Industrial Sector in Terawatt Hours



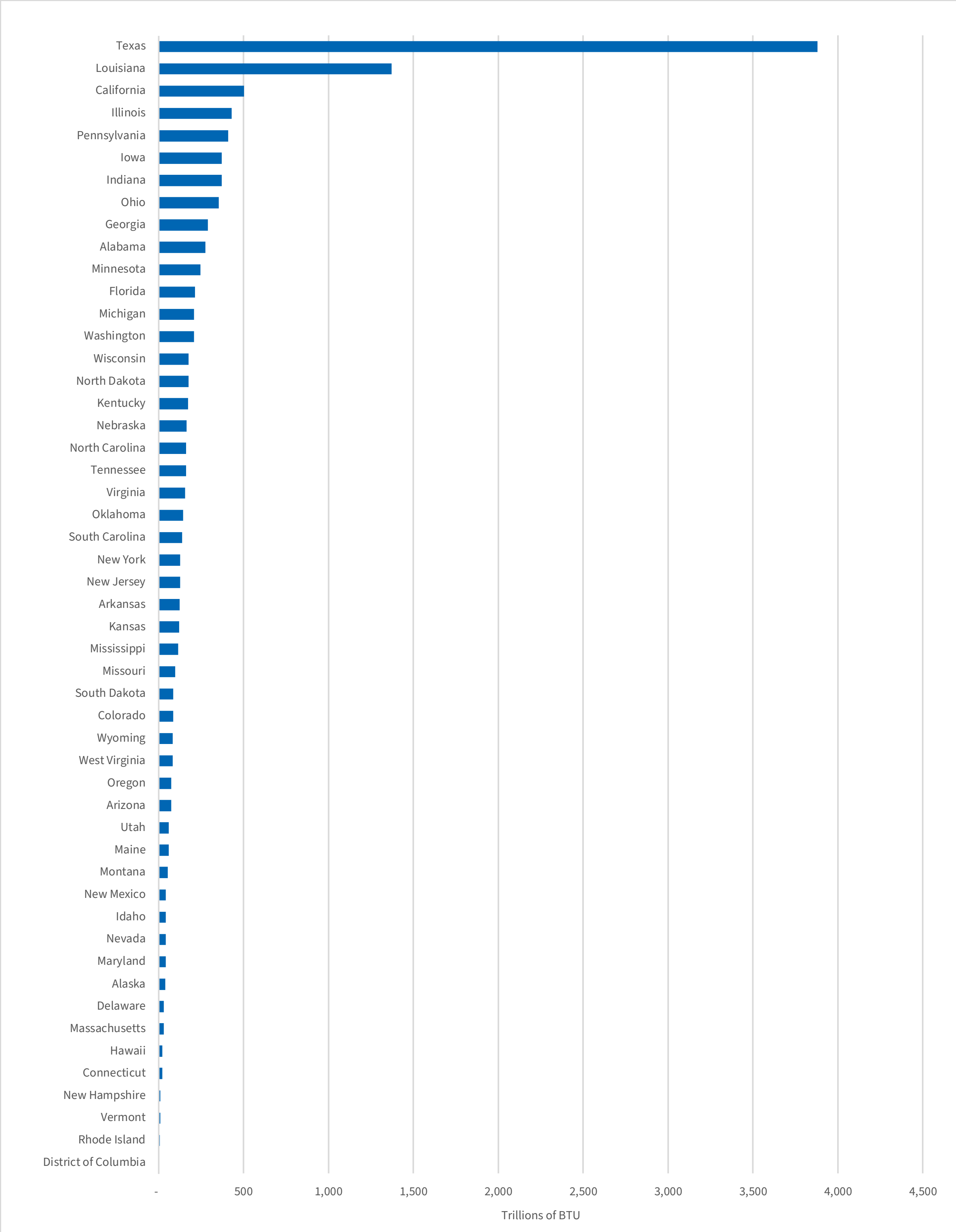
Appendix Figure 15: 2019 Natural Gas Consumed by the Industrial Sector



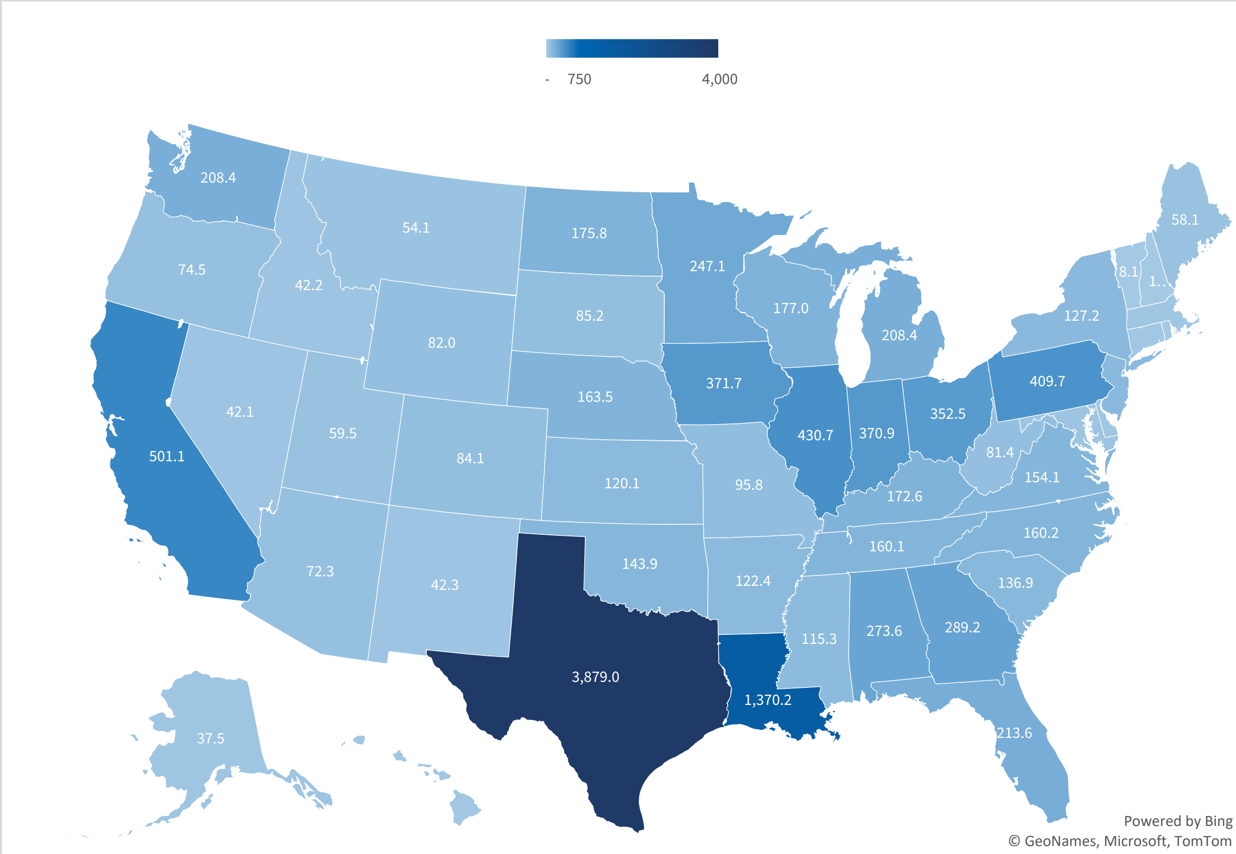
Appendix Figure 16: 2019 Natural Gas Consumed by the Industrial Sector in Billions of Cubic Feet

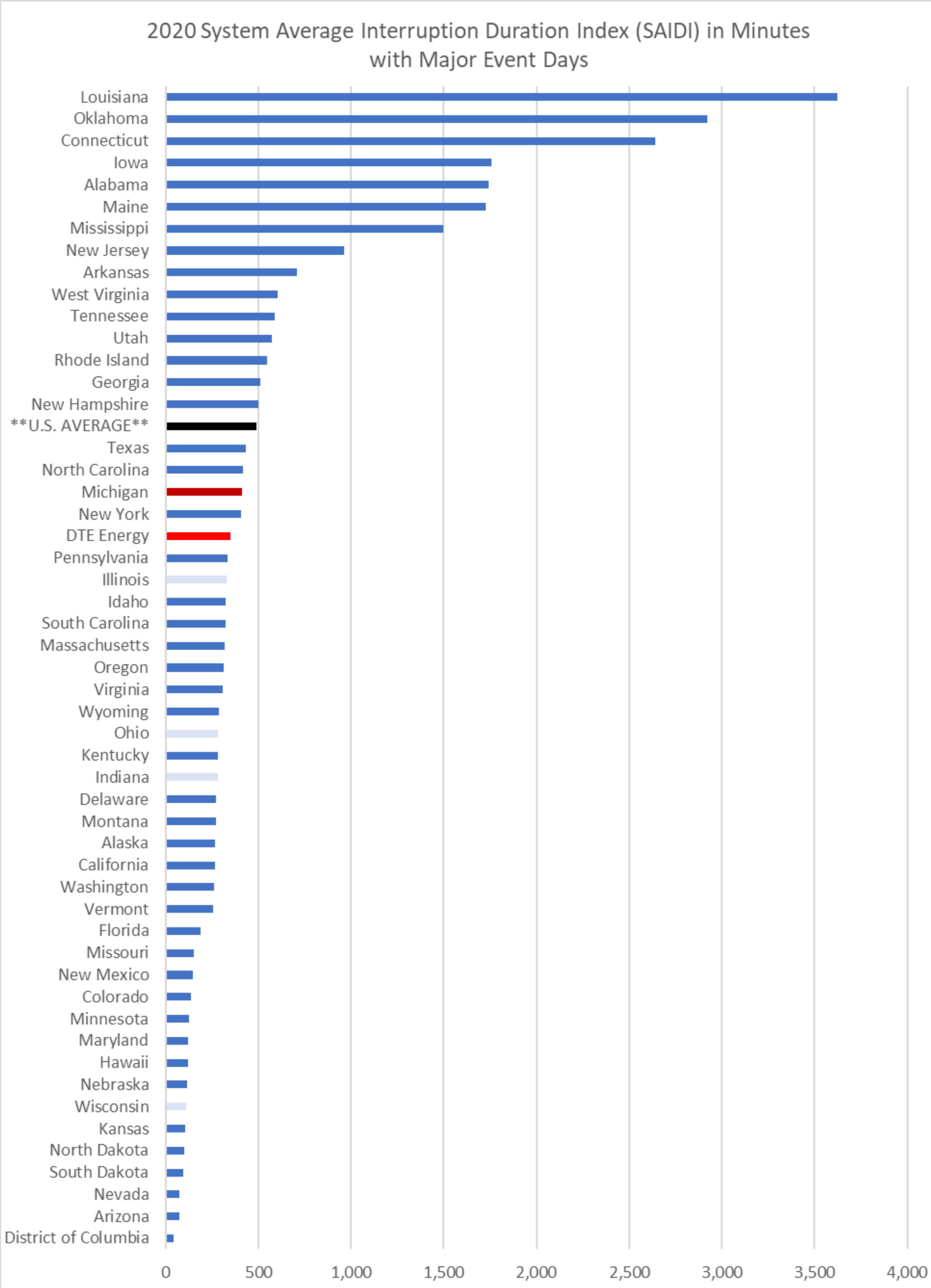


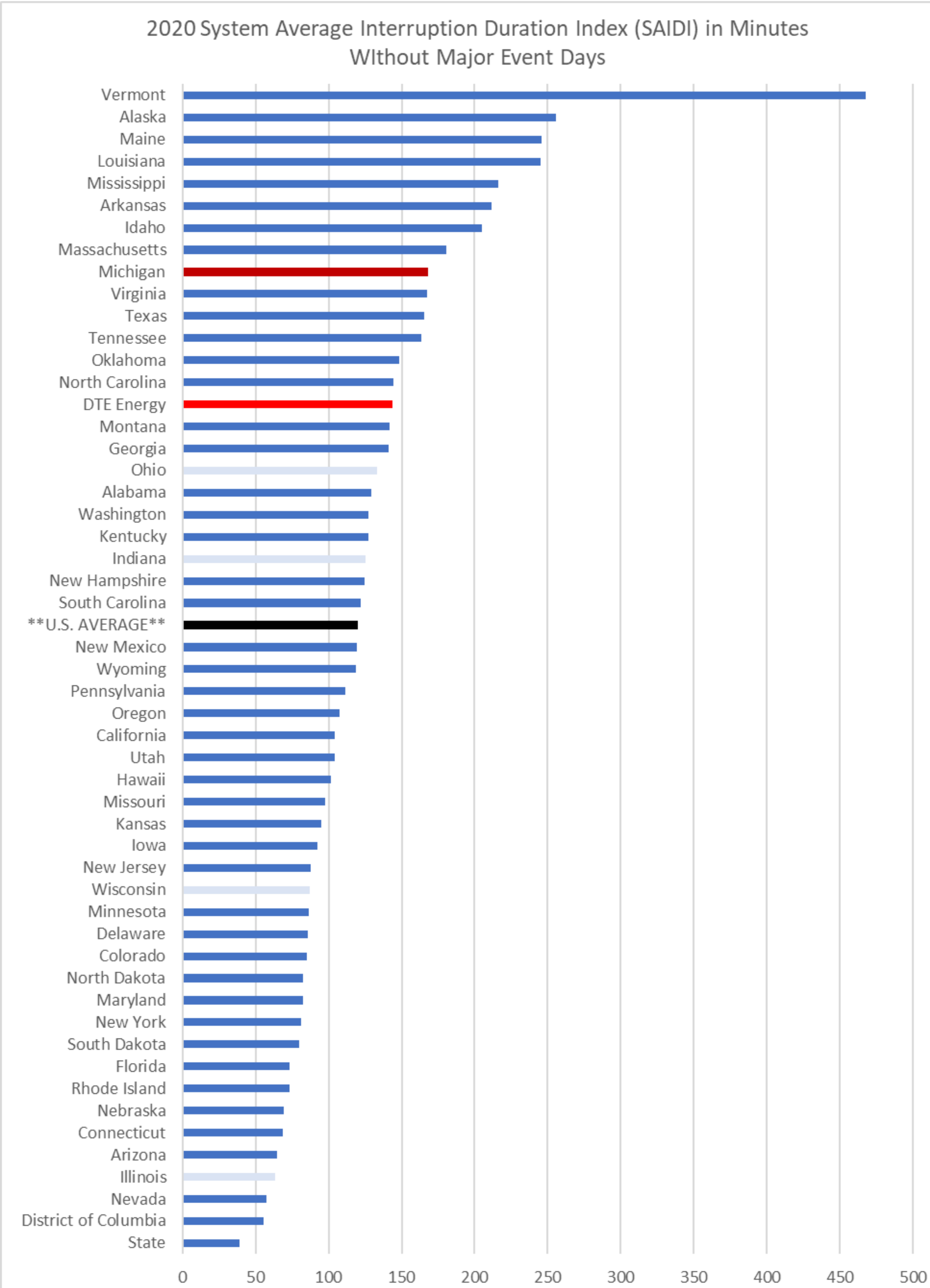
Appendix Figure 17: 2019 Other Heating Fuel Use by the Industrial Sector

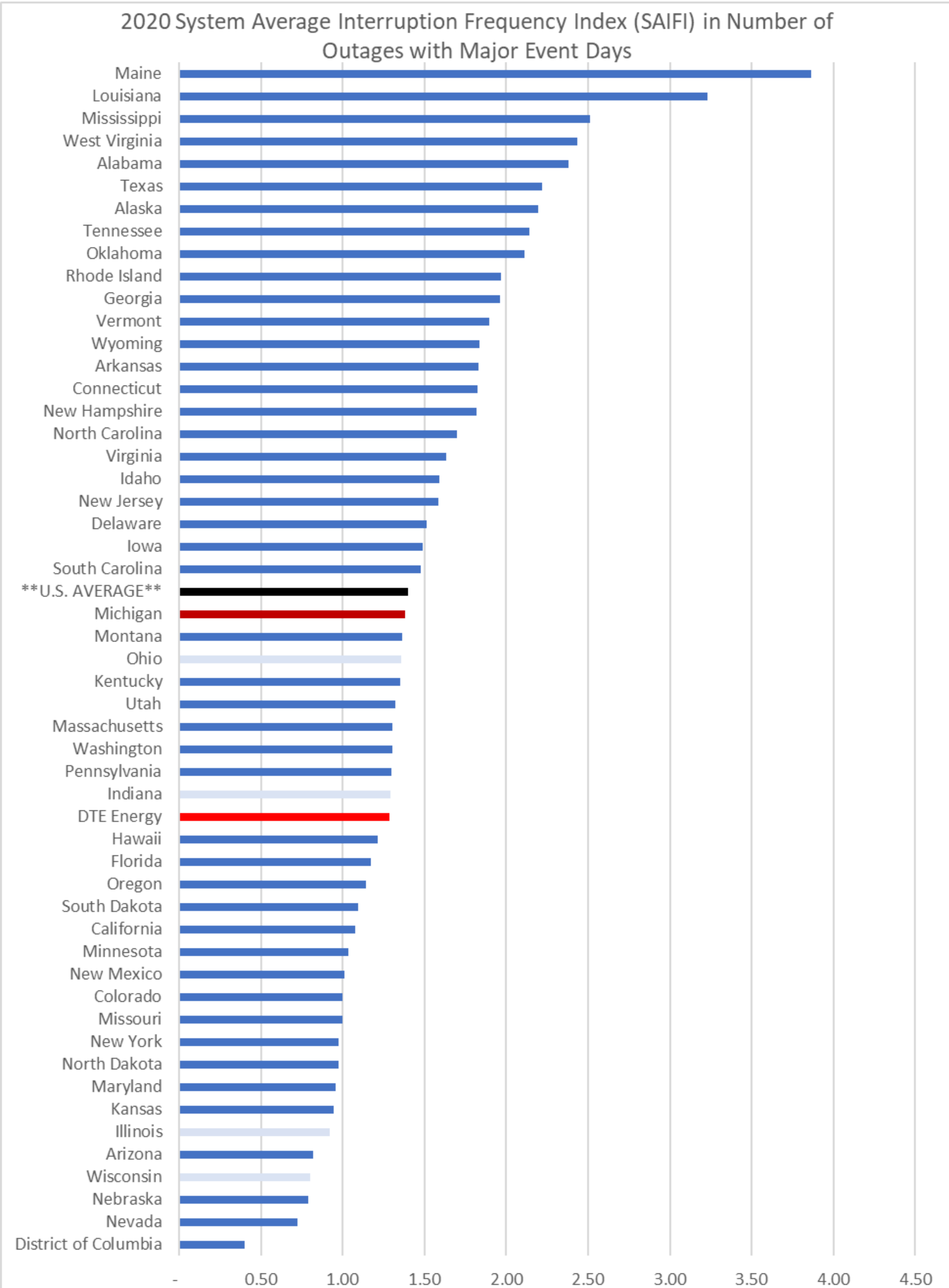


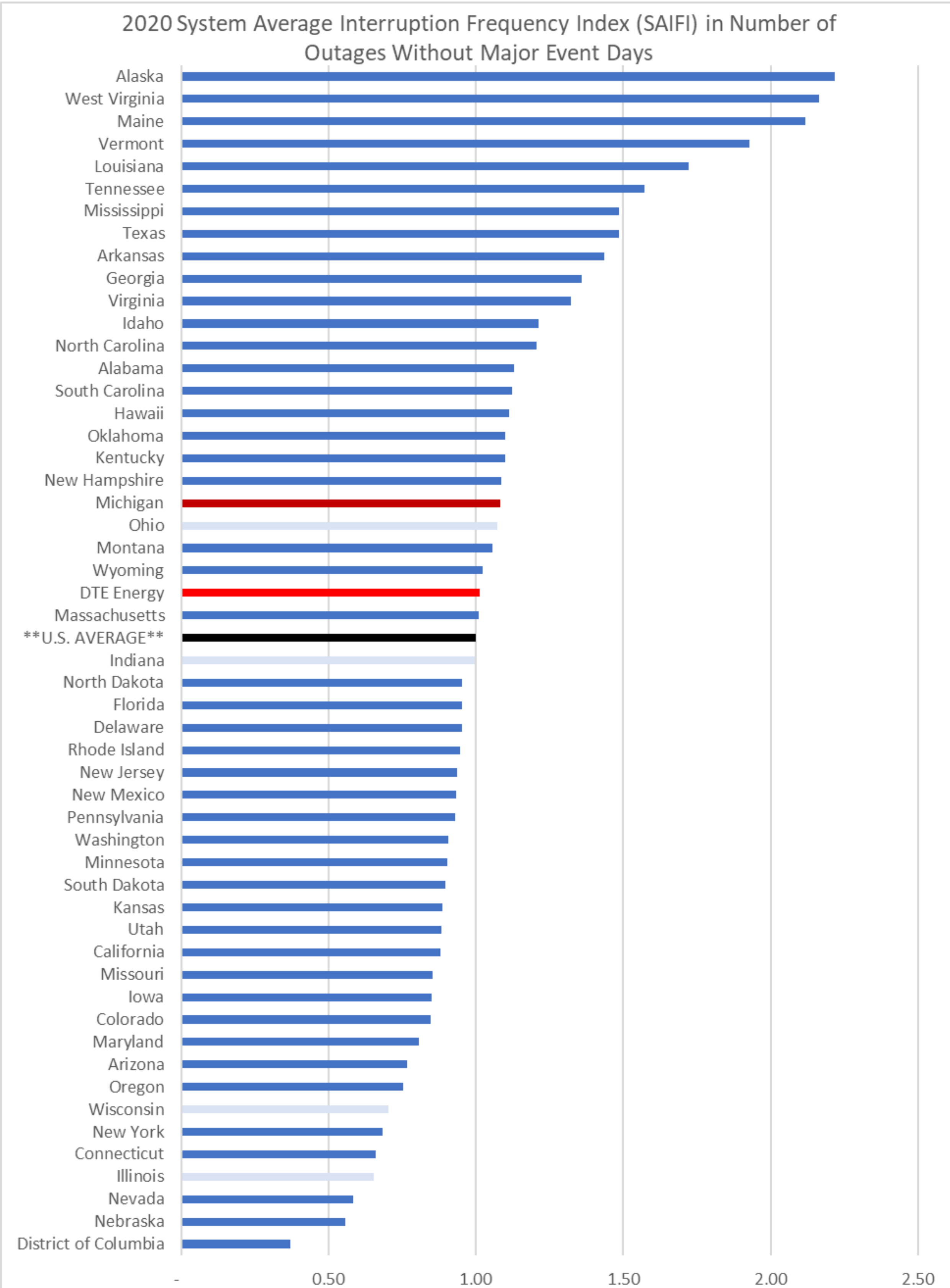
Appendix Figure 18: 2019 Other Heating Fuel Use by the Industrial Sector in Trillions of BTU

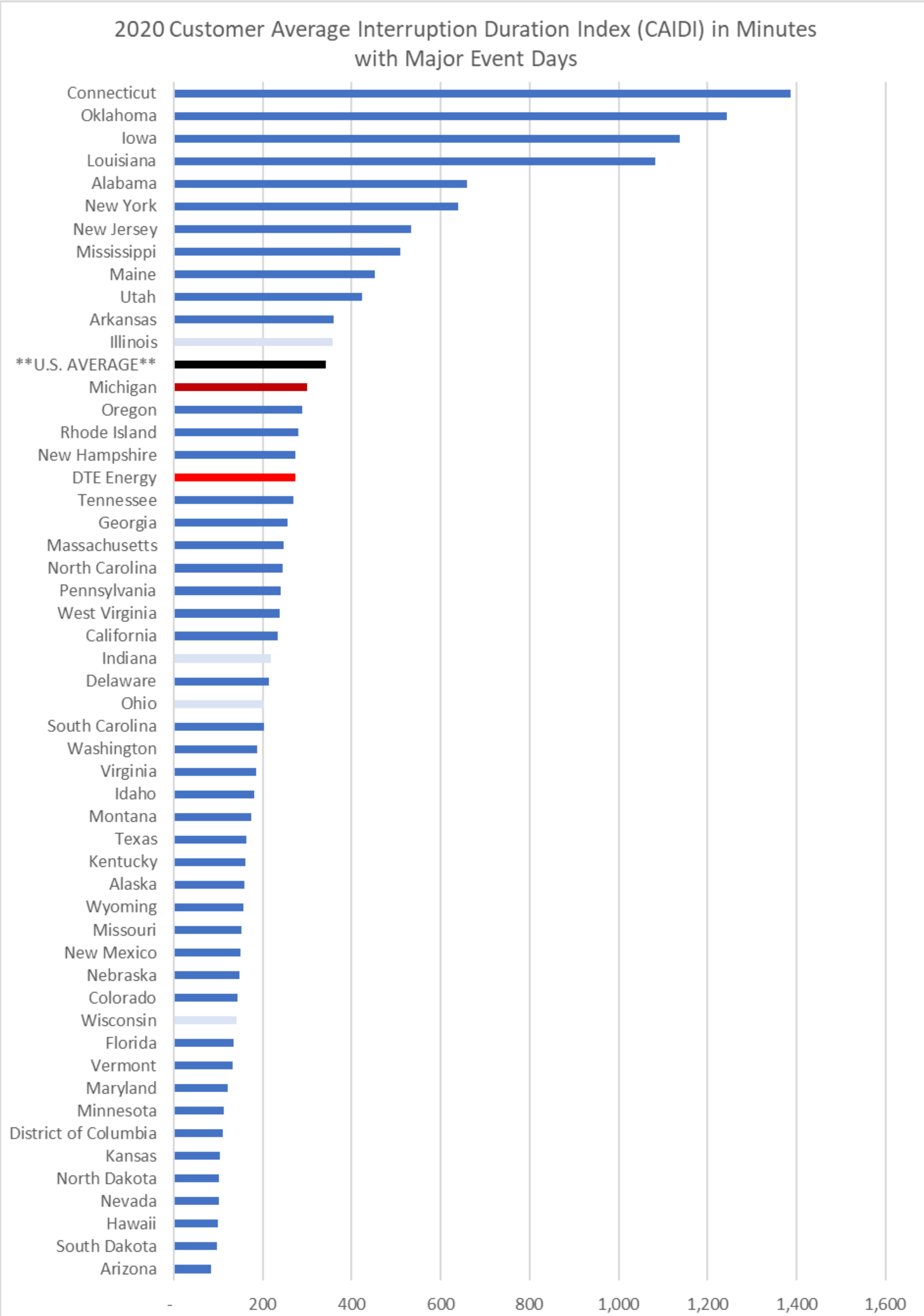


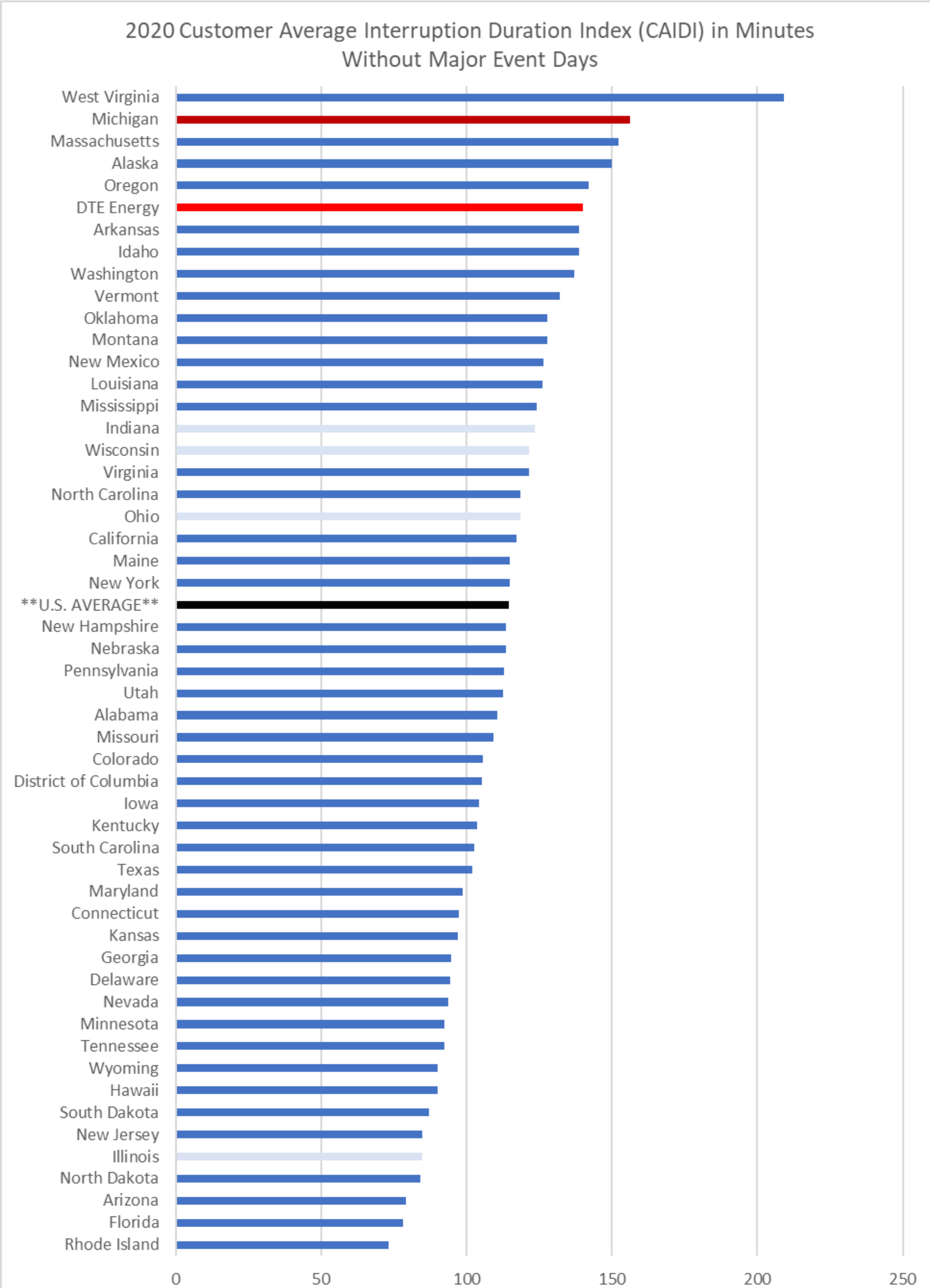

2020 System Average Interruption Duration Index (SAIDI) in Minutes with Major Event Days
Louisiana
Oklahoma
Connecticut
Iowa
Alabama
Maine
Mississippi
New Jersey
Arkansas
West Virginia
Tennessee
Utah
Rhode Island
Georgia
New Hampshire
U.S. AVERAGE
Texas
North Carolina
Michigan
New York
DTE Energy
Pennsylvania
Illinois
Idaho
South Carolina
Massachusetts
Oregon
Virginia
Wyoming
Ohio
Kentucky
Indiana
Delaware
Montana
Alaska
California
Washington
Vermont
Florida
Missouri
New Mexico
Colorado
Minnesota
Maryland
Hawaii
Nebraska
Wisconsin
Kansas
North Dakota
South Dakota
Nevada
Arizona
District of Columbia
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000

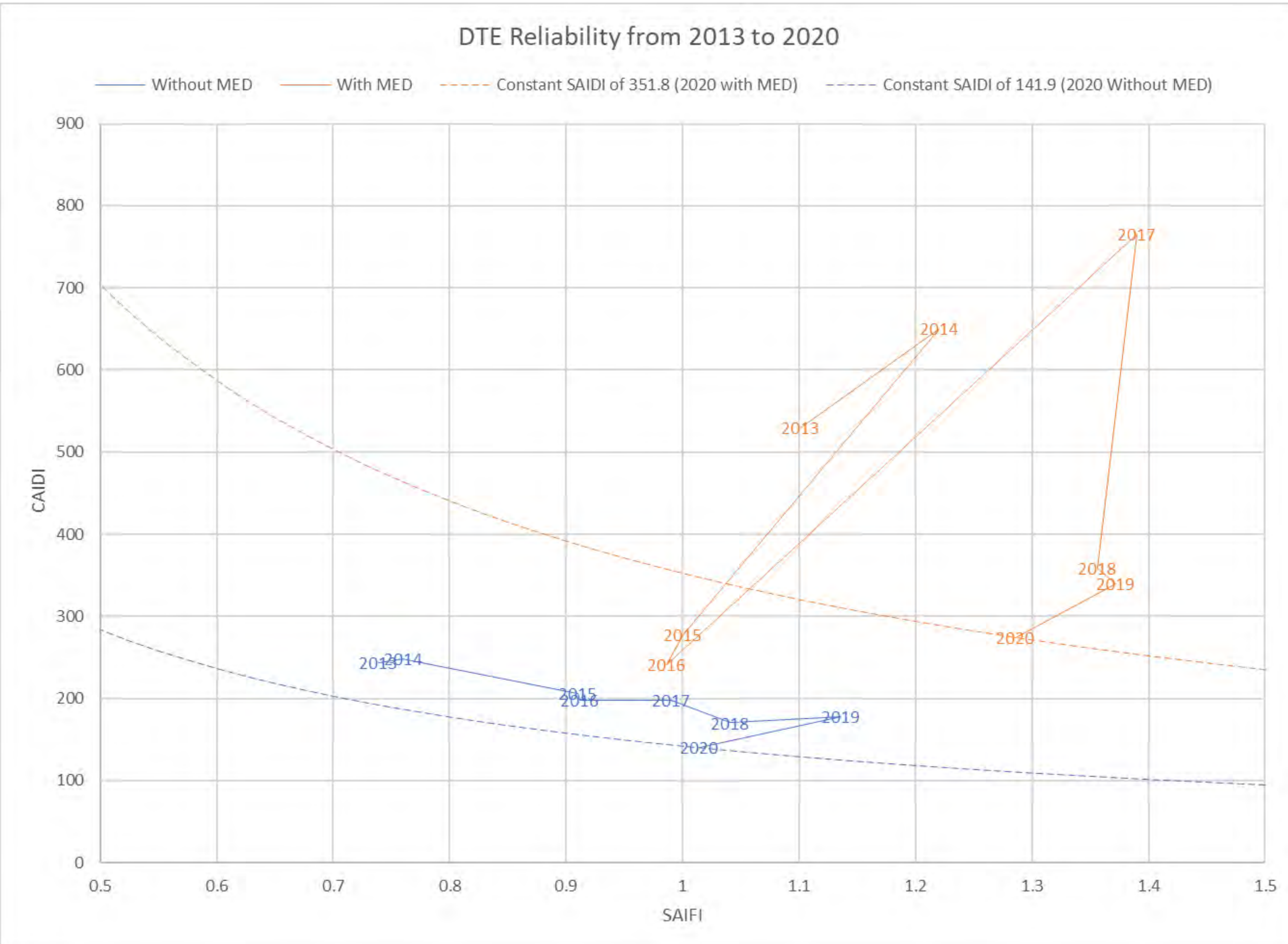

2020 System Average Interruption Duration Index (SAIDI) in Minutes
WIthout Major Event Days
Vermont
Alaska
Maine
Louisiana
Mississippi
Arkansas
Idaho
Massachusetts
Michigan
Virginia
Texas
Tennessee
Oklahoma
North Carolina
DTE Energy
Montana
Georgia
Ohio
Alabama
Washington
Kentucky
Indiana
New Hampshire
South Carolina
U.S. AVERAGE
New Mexico
Wyoming
Pennsylvania
Oregon
California
Utah
Hawaii
Missouri
Kansas
Iowa
New Jersey
Wisconsin
Minnesota
Delaware
Colorado
North Dakota
Maryland
New York
South Dakota
Florida
Rhode Island
Nebraska
Connecticut
Arizona
Illinois
Nevada
District of Columbia
State
0
50
100
150
200
250
300
350
400
450
500

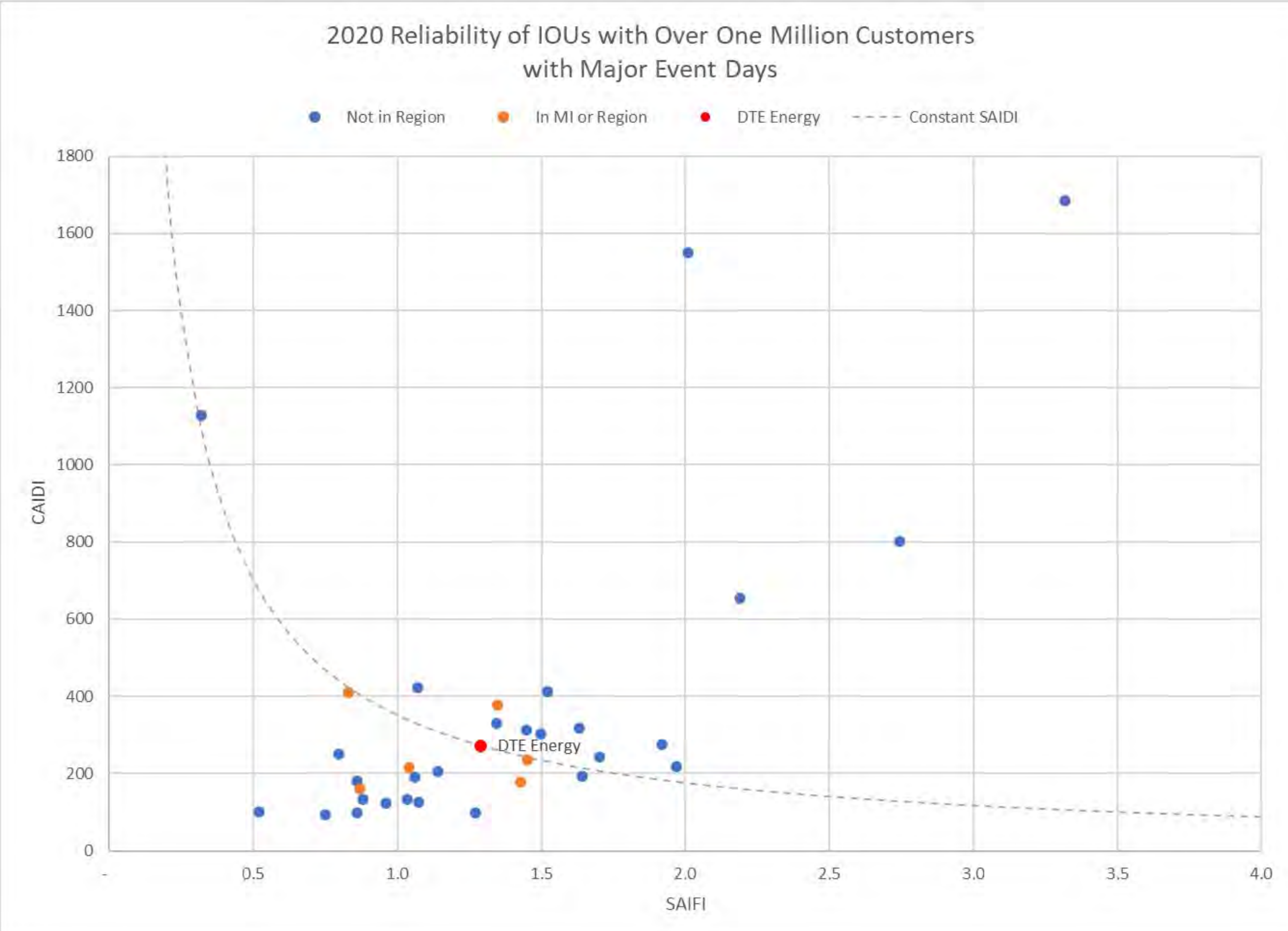

2020 System Average Interruption Frequency Index (SAIFI) in Number of Outages with Major Event Days
Maine
Louisiana
Mississippi
West Virginia
Alabama
Texas
Alaska
Tennessee
Oklahoma
Rhode Island
Georgia
Vermont
Wyoming
Arkansas
Connecticut
New Hampshire
North Carolina
Virginia
Idaho
New Jersey
Delaware
Iowa
South Carolina
U.S. AVERAGE
Michigan
Montana
Ohio
Kentucky
Utah
Massachusetts
Washington
Pennsylvania
Indiana
DTE Energy
Hawaii
Florida
Oregon
South Dakota
California
Minnesota
New Mexico
Colorado
Missouri
New York
North Dakota
Maryland
Kansas
Illinois
Arizona
Wisconsin
Nebraska
Nevada
District of Columbia
-
0.50
1.00
1.50
2.00
2.50
3.00
3.50
4.00
4.50

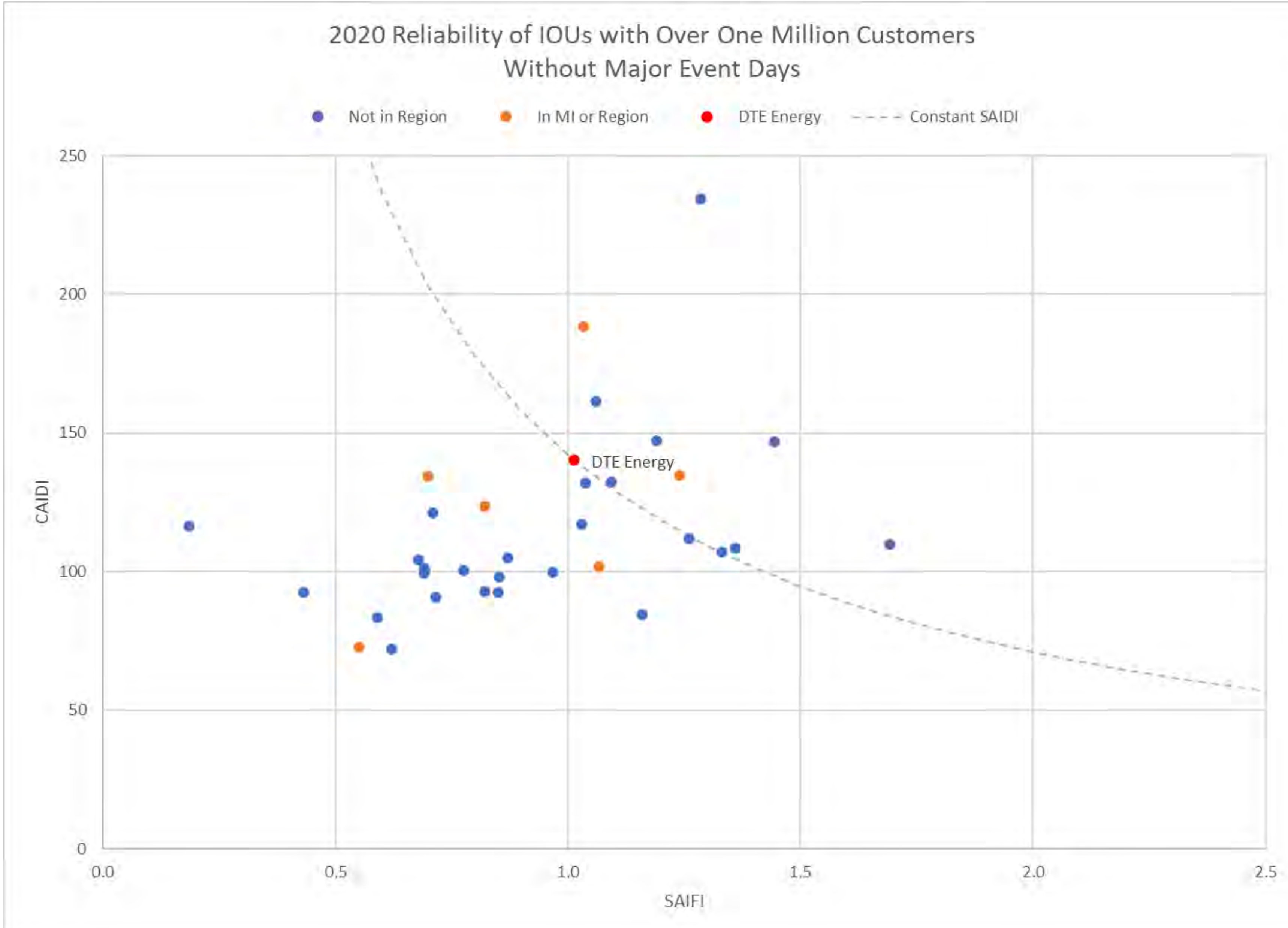

2020 System Average Interruption Frequency Index (SAIFI) in Number of Outages Without Major Event Days
Alaska
West Virginia
Maine
Vermont
Louisiana
Tennessee
Mississippi
Texas
Arkansas
Georgia
Virginia
Idaho
North Carolina
Alabama
South Carolina
Hawaii
Oklahoma
Kentucky
New Hampshire
Michigan
Ohio
Montana
Wyoming
DTE Energy
Massachusetts
U.S. AVERAGE
Indiana
North Dakota
Florida
Delaware
Rhode Island
New Jersey
New Mexico
Pennsylvania
Washington
Minnesota
South Dakota
Kansas
Utah
California
Missouri
Iowa
Colorado
Maryland
Arizona
Oregon
Wisconsin
New York
Connecticut
Illinois
Nevada
Nebraska
District of Columbia
-
0.50
1.00
1.50
2.00
2.50

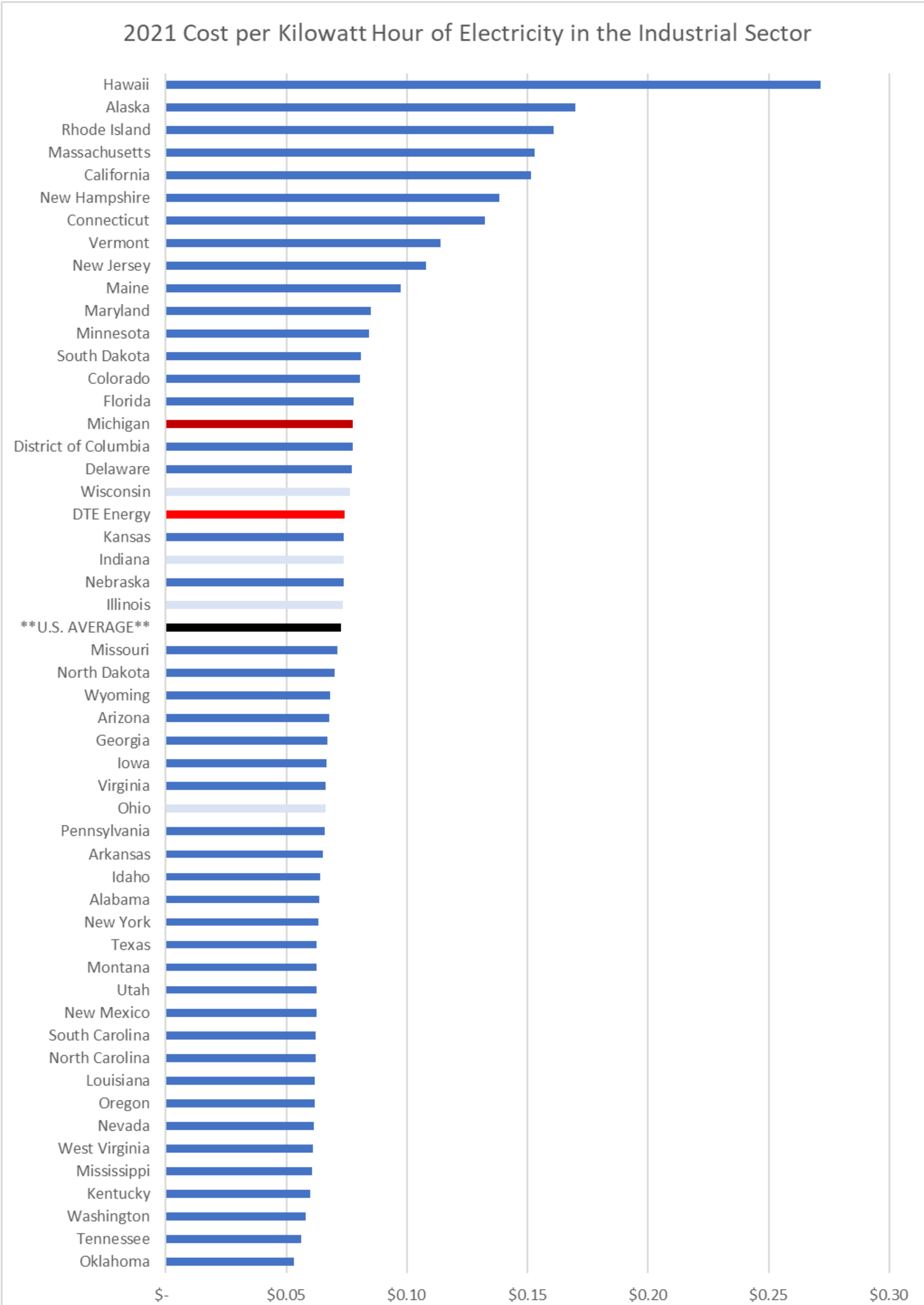

2020 Customer Average Interruption Duration Index (CAIDI) in Minutes with Major Event Days
Connecticut
Oklahoma
Iowa
Louisiana
Alabama
New York
New Jersey
Mississippi
Maine
Utah
Arkansas
Illinois
U.S. AVERAGE
Michigan
Oregon
Rhode Island
New Hampshire
DTE Energy
Tennessee
Georgia
Massachusetts
North Carolina
Pennsylvania
West Virginia
California
Indiana
Delaware
Ohio
South Carolina
Washington
Virginia
Idaho
Montana
Texas
Kentucky
Alaska
Wyoming
Missouri
New Mexico
Nebraska
Colorado
Wisconsin
Florida
Vermont
Maryland
Minnesota
District of Columbia
Kansas
North Dakota
Nevada
Hawaii
South Dakota
Arizona
-
200
400
600
800
1,000
1,200
1,400
1,600

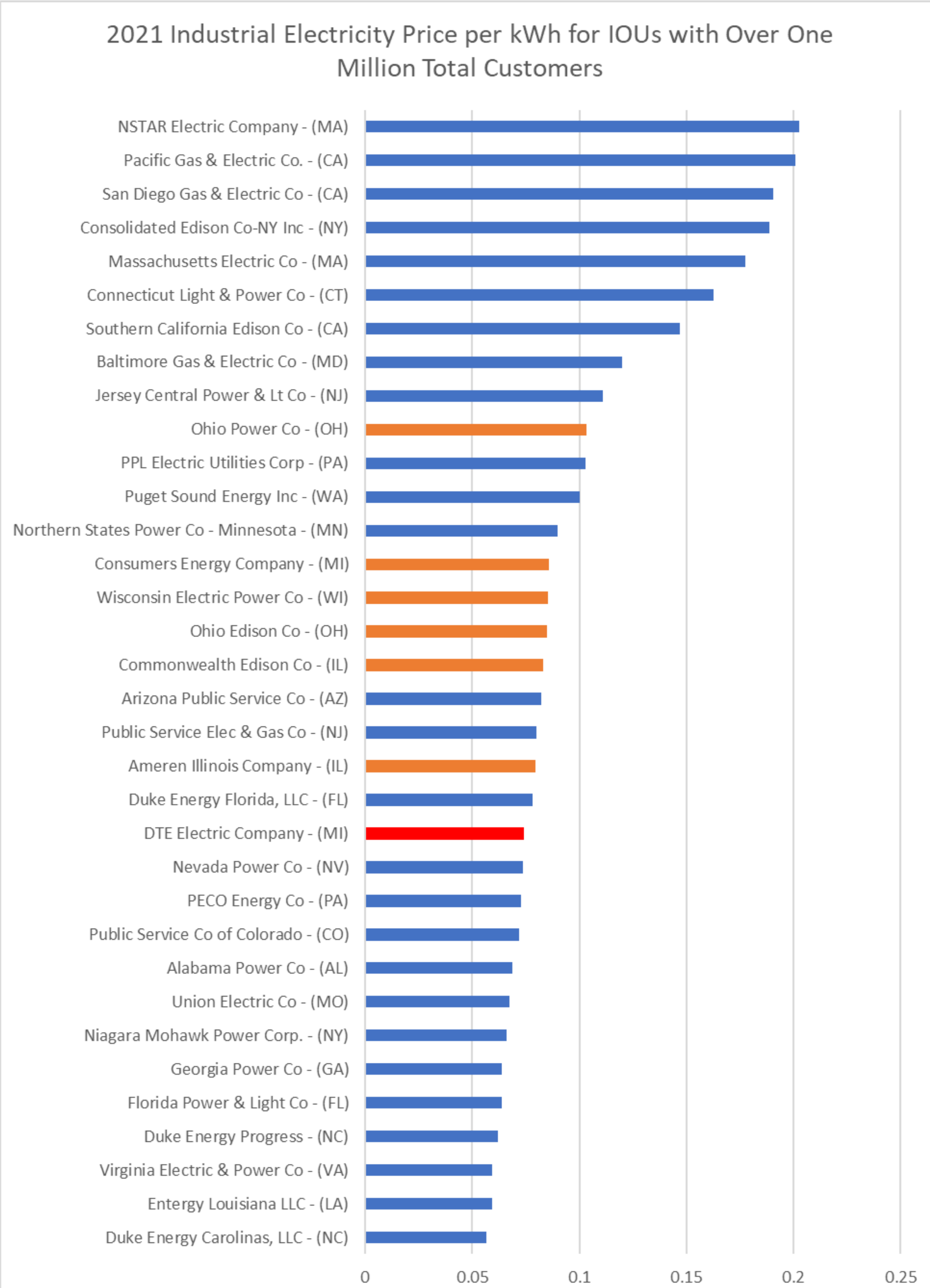

2020 Customer Average Interruption Duration Index (CAIDI) in Minutes
Without Major Event Days
West Virginia
Michigan
Massachusetts
Alaska
Oregon
DTE Energy
Arkansas
Idaho
Washington
Vermont
Oklahoma
Montana
New Mexico
Louisiana
Mississippi
Indiana
Wisconsin
Virginia
North Carolina
Ohio
California
Maine
New York
U.S. AVERAGE
New Hampshire
Nebraska
Pennsylvania
Utah
Alabama
Missouri
Colorado
District of Columbia
Iowa
Kentucky
South Carolina
Texas
Maryland
Connecticut
Kansas
Georgia
Delaware
Nevada
Minnesota
Tennessee
Wyoming
Hawaii
South Dakota
New Jersey
Illinois
North Dakota
Arizona
Florida
Rhode Island
0
50
100
150
200
250

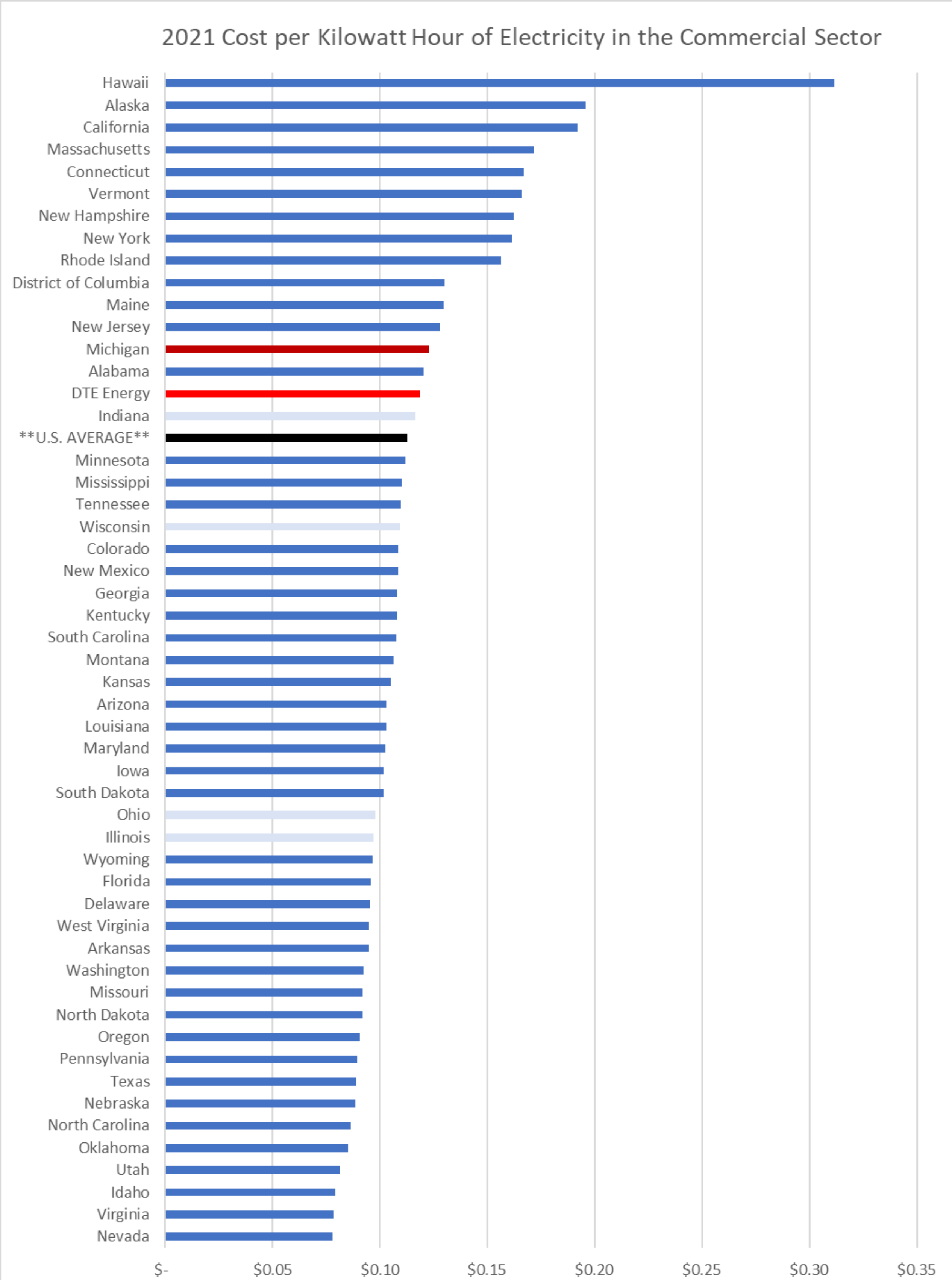

DTE Reliability from 2013 to 2020
Without MED
With MED
Constant SAIDI of 351.8 (2020 with MED)
Constant SAIDI of 141.9 (2020 Without MED)
CAIDI
SAIFI
900
800
700
600
500
400
300
200
100
0
0.5
0.6
0.7
0.8
0.9
1
1.1
1.2
1.3
1.4
1.5
2013
2014
2015
2016
2017
2018
2019
2020

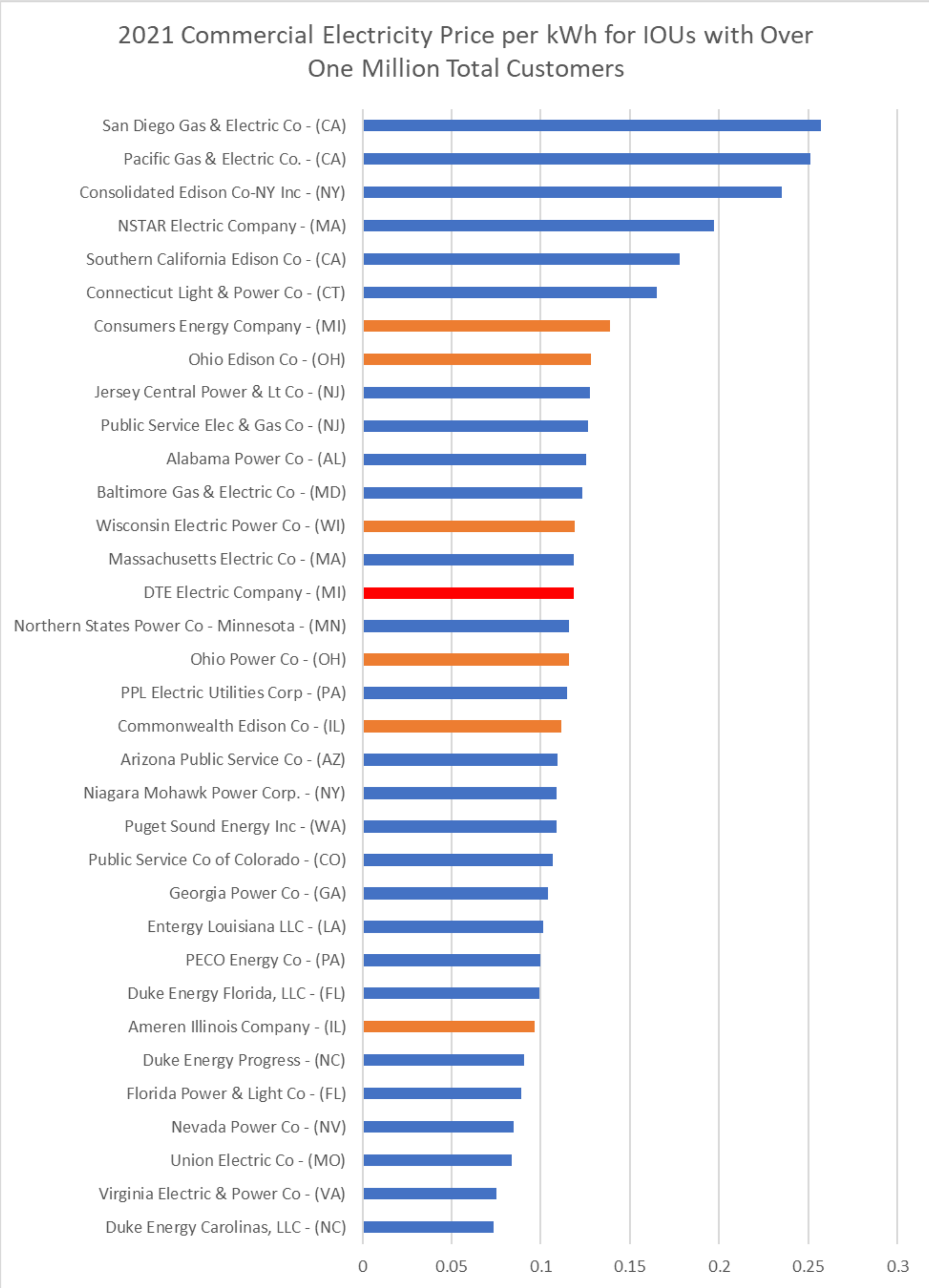

2020 Reliability of IOUs with Over One Million Customers
with Major Event Days
Not in Region
In MI or Region
DTE Energy
Constant SAIDI
CAIDI
1800
1600
1400
1200
1000
800
600
400
200
0
DTE Energy
-
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
SAIFI

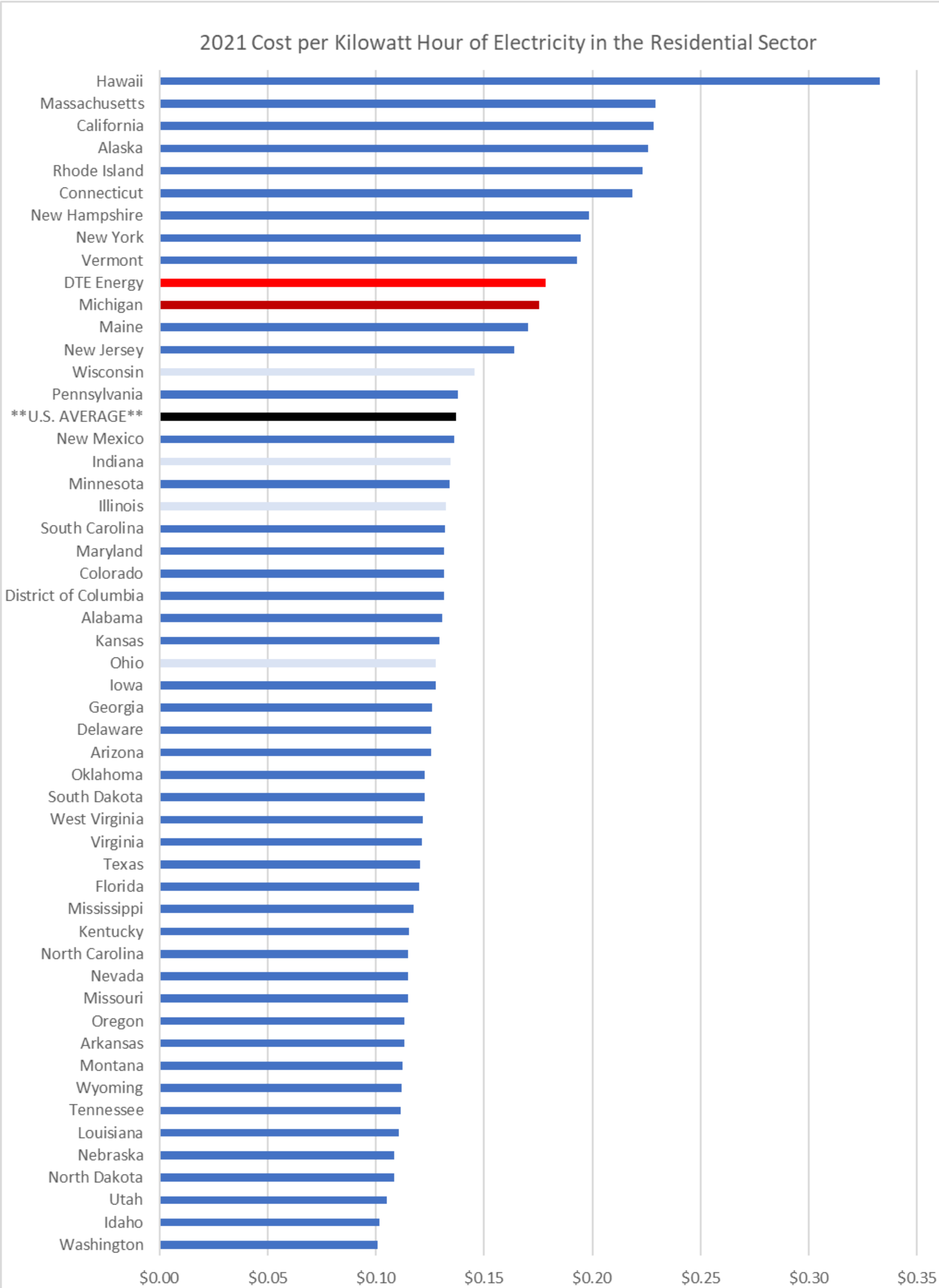

2020 Reliability of IOUs with Over One Million Customers
Without Major Event Days
Not in Region
In MI or Region
DTE Energy
Constant SAIDI
CAIDI
250
200
150
100
50
0
0.0
0.5
1.0
1.5
2.0
2.5
SAIFI
DTE Energy

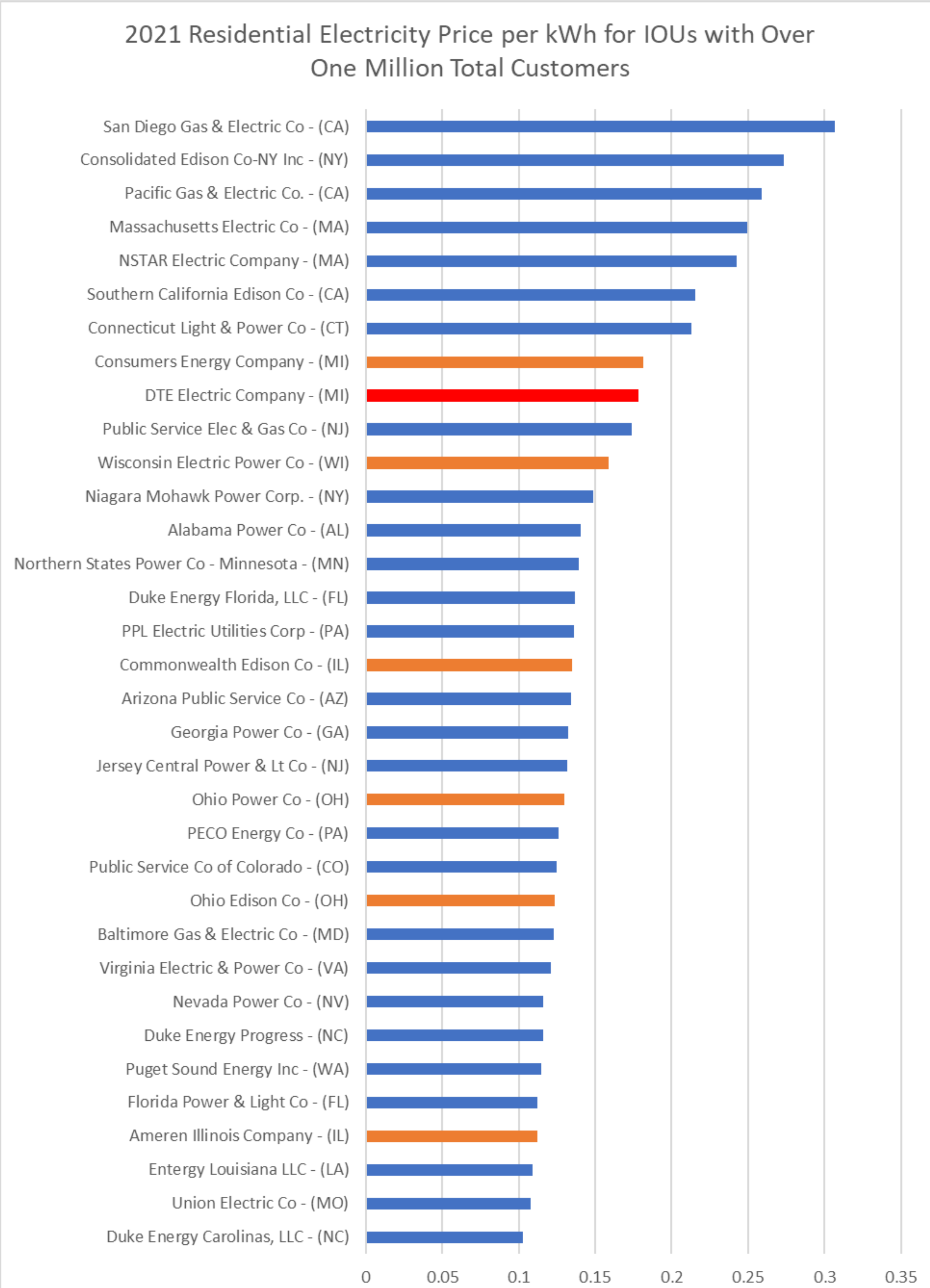

2021 Cost per Kilowatt Hour of Electricity in the Industrial Sector
Hawaii
Alaska
Rhode Island
Massachusetts
California
New Hampshire
Connecticut
Vermont
New Jersey
Maine
Maryland
Minnesota
South Dakota
Colorado
Florida
Michigan
District of Columbia
Delaware
Wisconsin
DTE Energy
Kansas
Indiana
Nebraska
Illinois
U.S. AVERAGE
Missouri
North Dakota
Wyoming
Arizona
Georgia
Iowa
Virginia
Ohio
Pennsylvania
Arkansas
Idaho
Alabama
New York
Texas
Montana
Utah
New Mexico
South Carolina
North Carolina
Louisiana
Oregon
Nevada
West Virginia
Mississippi
Kentucky
Washington
Tennessee
Oklahoma
$-
$0.05
$0.10
$0.15
$0.20
$0.25
$0.30

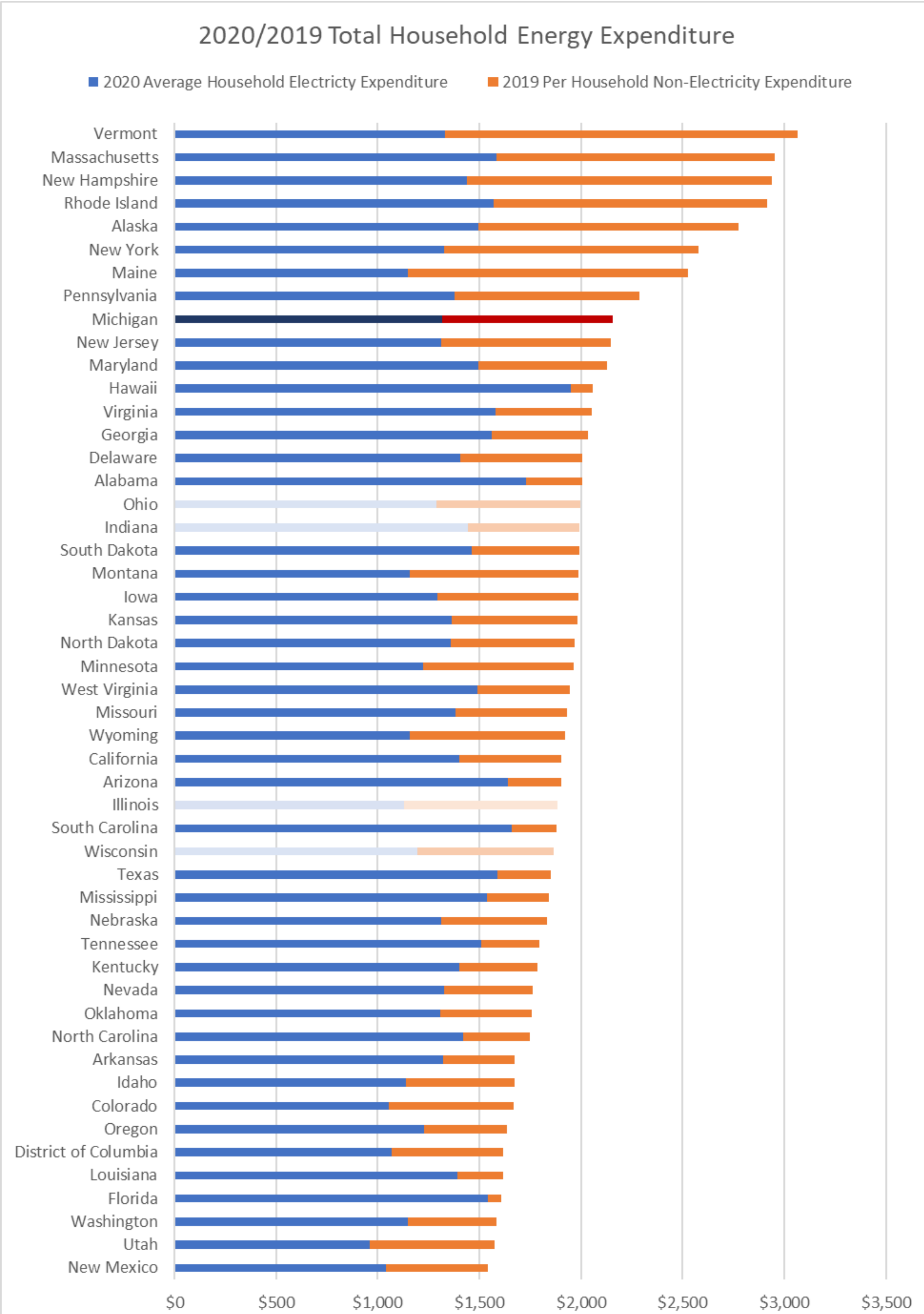

2021 Industrial Electricity Price per kWh for IOUs with Over One Million Total Customers
NSTAR Electric Company - (MA)
Pacific Gas & Electric Co. - (CA)
San Diego Gas & Electric Co - (CA)
Consolidated Edison Co-NY Inc - (NY)
Massachusetts Electric Co - (MA)
Connecticut Light & Power Co - (CT)
Southern California Edison Co - (CA)
Baltimore Gas & Electric Co - (MD)
Jersey Central Power & Lt Co - (NJ)
Ohio Power Co - (OH)
PPL Electric Utilities Corp - (PA)
Puget Sound Energy Inc - (WA)
Northern States Power Co - Minnesota - (MN)
Consumers Energy Company - (MI)
Wisconsin Electric Power Co - (WI)
Ohio Edison Co - (OH)
Commonwealth Edison Co - (IL)
Arizona Public Service Co - (AZ)
Public Service Elec & Gas Co - (NJ)
Ameren Illinois Company - (IL)
Duke Energy Florida, LLC - (FL)
DTE Electric Company - (MI)
Nevada Power Co - (NV)
PECO Energy Co - (PA)
Public Service Co of Colorado - (CO)
Alabama Power Co - (AL)
Union Electric Co - (MO)
Niagara Mohawk Power Corp. - (NY)
Georgia Power Co - (GA)
Florida Power & Light Co - (FL)
Duke Energy Progress - (NC)
Virginia Electric & Power Co - (VA)
Entergy Louisiana LLC - (LA)
Duke Energy Carolinas, LLC - (NC)
0
0.05
0.1
0.15
0.2
0.25

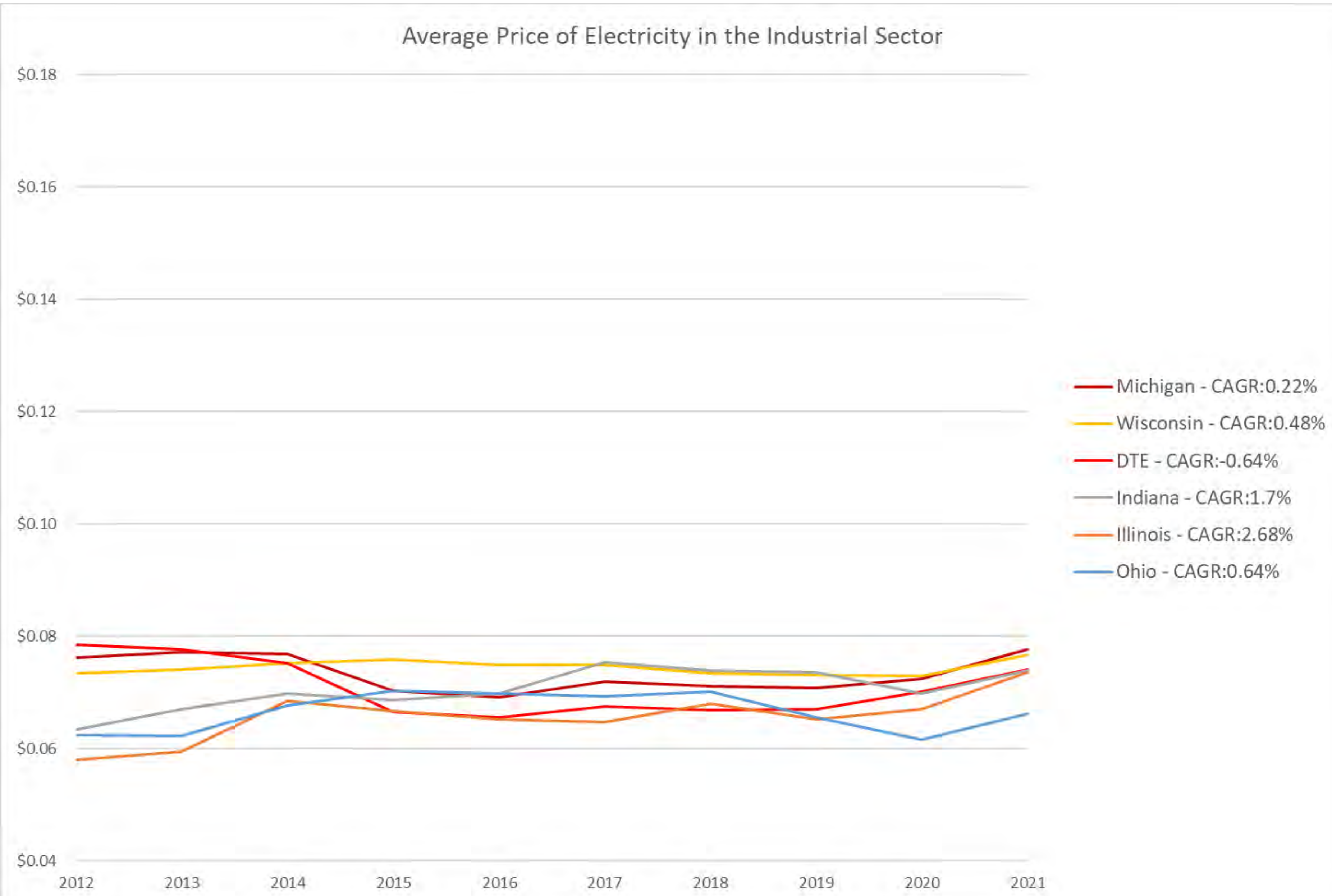

2021 Cost per Kilowatt Hour of Electricity in the Commercial Sector
Hawaii
Alaska
California
Massachusetts
Connecticut
Vermont
New Hampshire
New York
Rhode Island
District of Columbia
Maine
New Jersey
Michigan
Alabama
DTE Energy
Indiana
U.S. AVERAGE
Minnesota
Mississippi
Tennessee
Wisconsin
Colorado
New Mexico
Georgia
Kentucky
South Carolina
Montana
Kansas
Arizona
Louisiana
Maryland
Iowa
South Dakota
Ohio
Illinois
Wyoming
Florida
Delaware
West Virginia
Arkansas
Washington
Missouri
North Dakota
Oregon
Pennsylvania
Texas
Nebraska
North Carolina
Oklahoma
Utah
Idaho
Virginia
Nevada
$-
$0.05
$0.10
$0.15
$0.20
$0.25
$0.30
$0.35

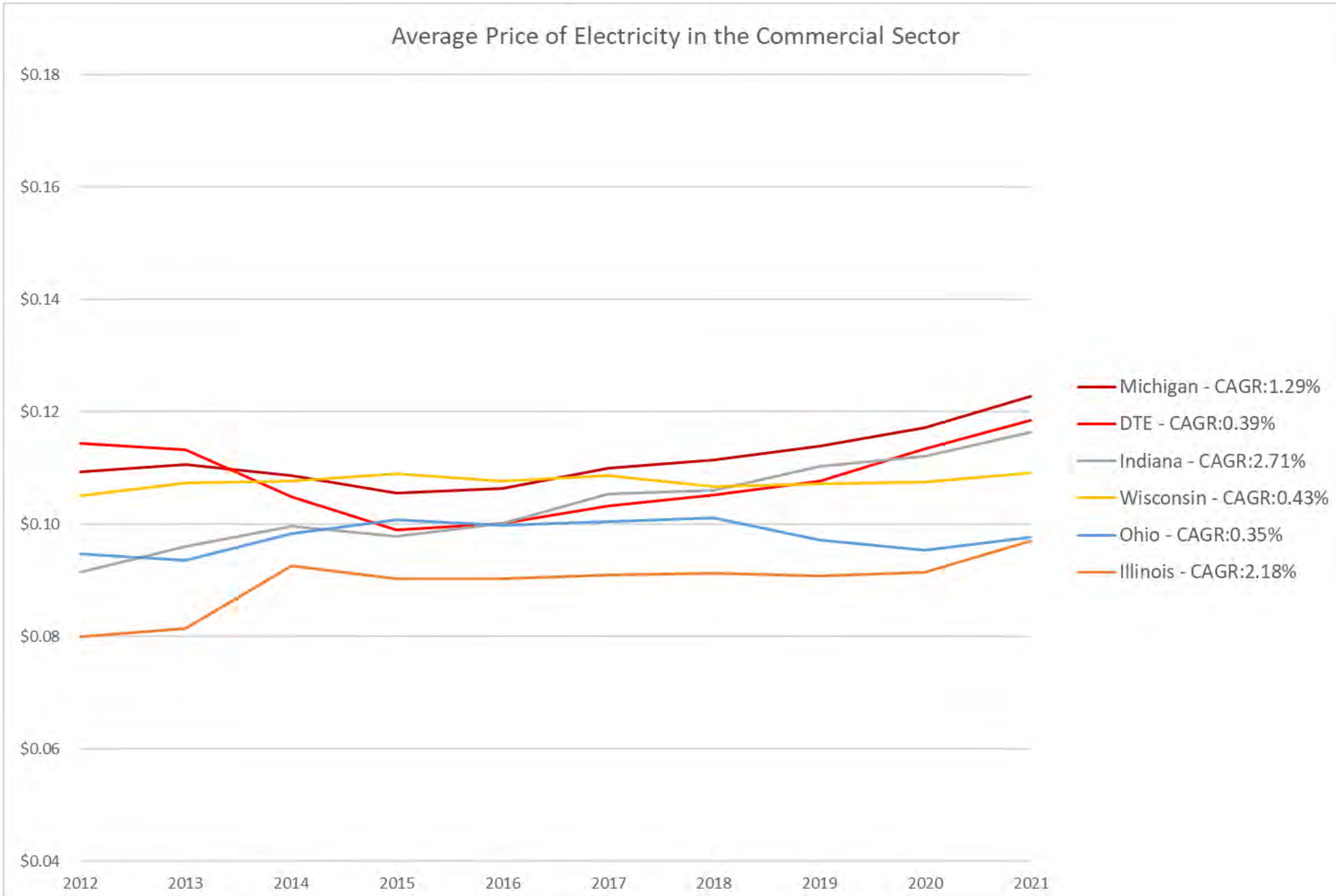

2021 Commercial Electricity Price per kWh for IOUs with Over One Million Total Customers
San Diego Gas & Electric Co - (CA)
Pacific Gas & Electric Co. - (CA)
Consolidated Edison Co-NY Inc - (NY)
NSTAR Electric Company - (MA)
Southern California Edison Co - (CA)
Connecticut Light & Power Co - (CT)
Consumers Energy Company - (MI)
Ohio Edison Co - (OH)
Jersey Central Power & Lt Co - (NJ)
Public Service Elec & Gas Co - (NJ)
Alabama Power Co - (AL)
Baltimore Gas & Electric Co - (MD)
Wisconsin Electric Power Co - (WI)
Massachusetts Electric Co - (MA)
DTE Electric Company - (MI)
Northern States Power Co - Minnesota - (MN)
Ohio Power Co - (OH)
PPL Electric Utilities Corp - (PA)
Commonwealth Edison Co - (IL)
Arizona Public Service Co - (AZ)
Niagara Mohawk Power Corp. - (NY)
Puget Sound Energy Inc - (WA)
Public Service Co of Colorado - (CO)
Georgia Power Co - (GA)
Entergy Louisiana LLC - (LA)
PECO Energy Co - (PA)
Duke Energy Florida, LLC - (FL)
Ameren Illinois Company - (IL)
Duke Energy Progress - (NC)
Florida Power & Light Co - (FL)
Nevada Power Co - (NV)
Union Electric Co - (MO)
Virginia Electric & Power Co - (VA)
Duke Energy Carolinas, LLC - (NC)
0
0.05
0.1
0.15
0.2
0.25
0.3

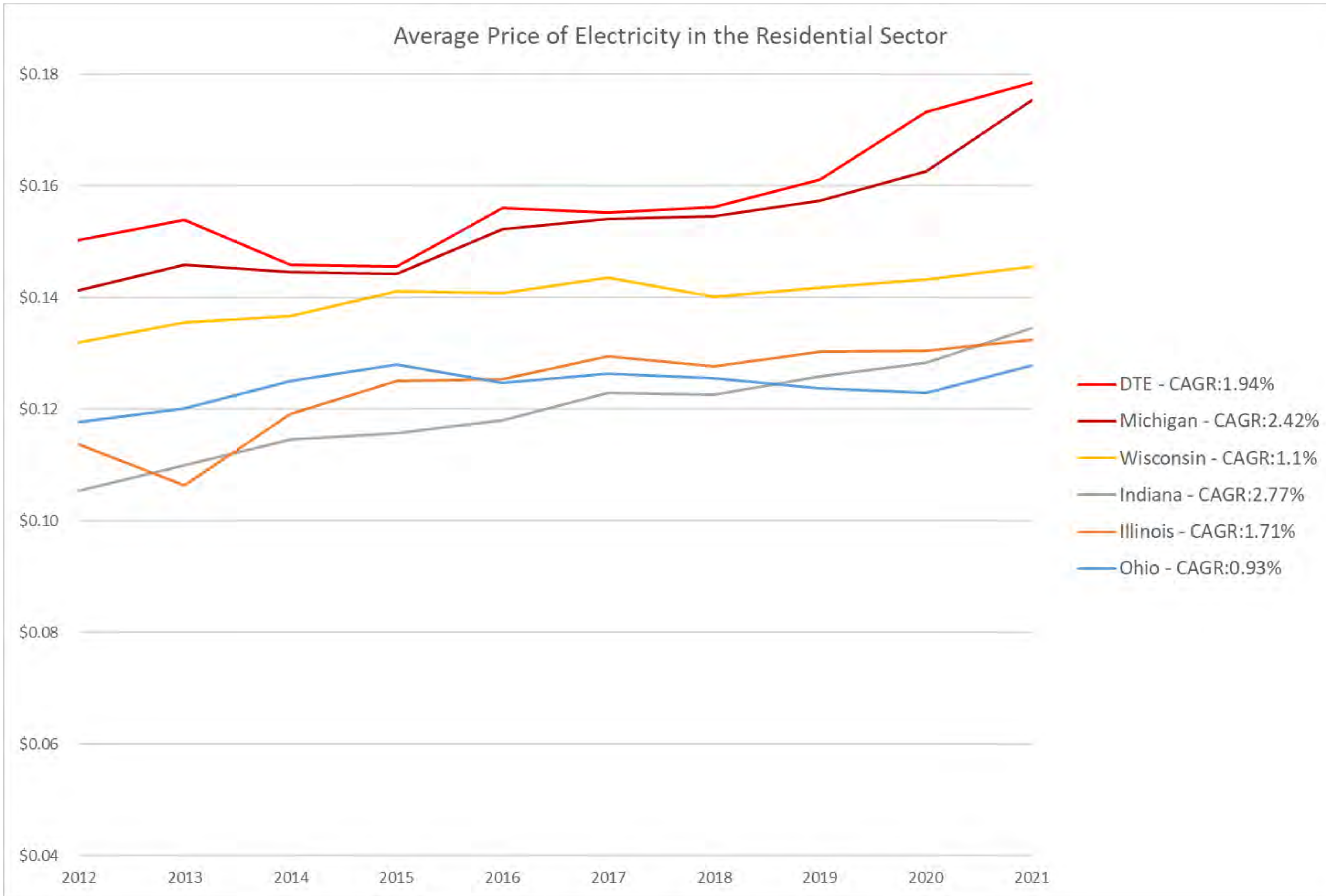

2021 Cost per Kilowatt Hour of Electricity in the Residential Sector
Hawaii
Massachusetts
California
Alaska
Rhode Island
Connecticut
New Hampshire
New York
Vermont
DTE Energy
Michigan
Maine
New Jersey
Wisconsin
Pennsylvania
U.S. AVERAGE
New Mexico
Indiana
Minnesota
Illinois
South Carolina
Maryland
Colorado
District of Columbia
Alabama
Kansas
Ohio
Iowa
Georgia
Delaware
Arizona
Oklahoma
South Dakota
West Virginia
Virginia
Texas
Florida
Mississippi
Kentucky
North Carolina
Nevada
Missouri
Oregon
Arkansas
Montana
Wyoming
Tennessee
Louisiana
Nebraska
North Dakota
Utah
Idaho
Washington
$0.00
$0.05
$0.10
$0.15
$0.20
$0.25
$0.30
$0.35

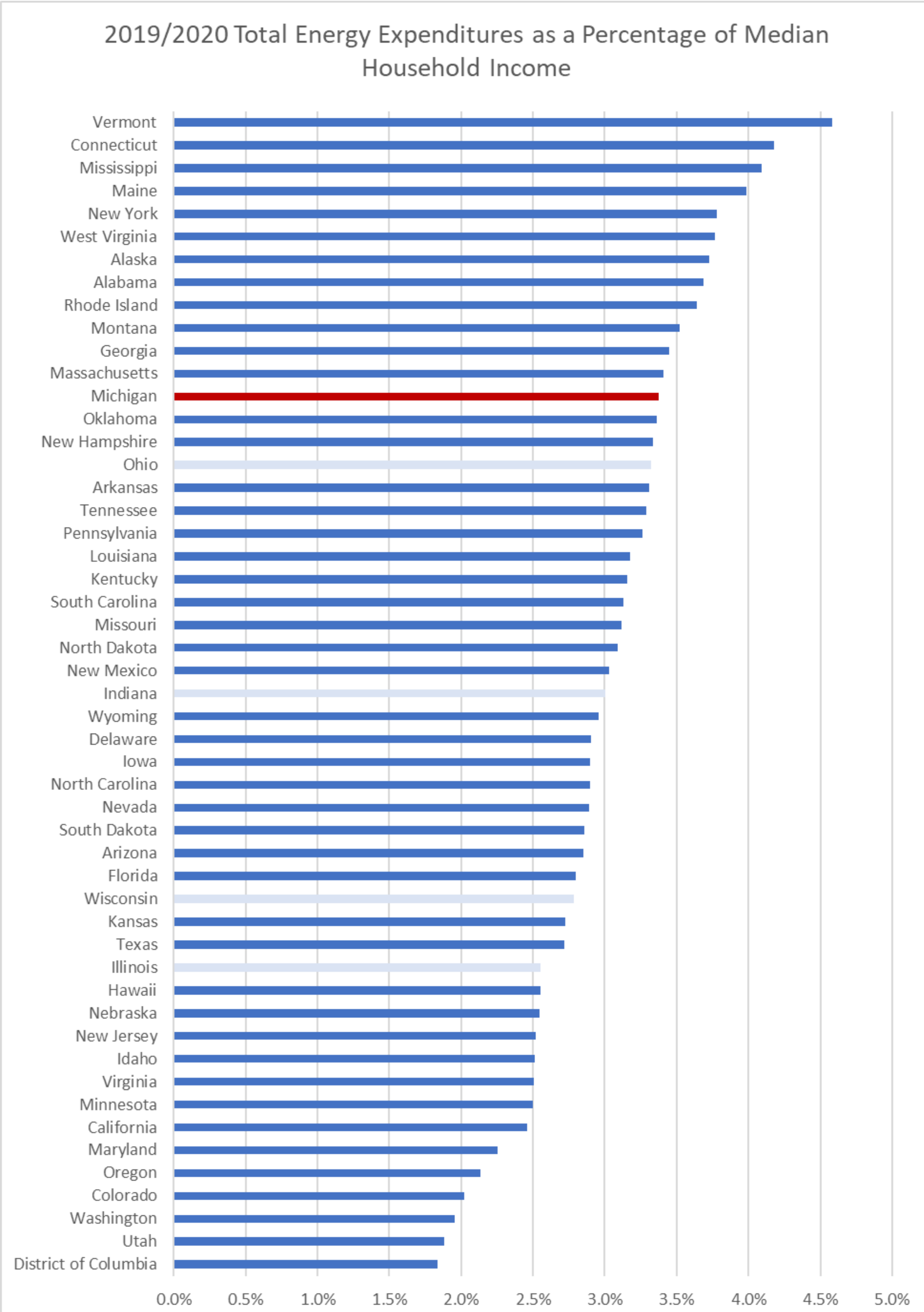

2021 Residential Electricity Price per kWh for IOUs with Over One Million Total Customers
San Diego Gas & Electric Co - (CA)
Consolidated Edison Co-NY Inc - (NY)
Pacific Gas & Electric Co. - (CA)
Massachusetts Electric Co - (MA)
NSTAR Electric Company - (MA)
Southern California Edison Co - (CA)
Connecticut Light & Power Co - (CT)
Consumers Energy Company - (MI)
DTE Electric Company - (MI)
Public Service Elec & Gas Co - (NJ)
Wisconsin Electric Power Co - (WI)
Niagara Mohawk Power Corp. - (NY)
Alabama Power Co - (AL)
Northern States Power Co - Minnesota - (MN)
Duke Energy Florida, LLC - (FL)
PPL Electric Utilities Corp - (PA)
Commonwealth Edison Co - (IL)
Arizona Public Service Co - (AZ)
Georgia Power Co - (GA)
Jersey Central Power & Lt Co - (NJ)
Ohio Power Co - (OH)
PECO Energy Co - (PA)
Public Service Co of Colorado - (CO)
Ohio Edison Co - (OH)
Baltimore Gas & Electric Co - (MD)
Virginia Electric & Power Co - (VA)
Nevada Power Co - (NV)
Duke Energy Progress - (NC)
Puget Sound Energy Inc - (WA)
Florida Power & Light Co - (FL)
Ameren Illinois Company - (IL)
Entergy Louisiana LLC - (LA)
Union Electric Co - (MO)
Duke Energy Carolinas, LLC - (NC)
0
0.05
0.1
0.15
0.2
0.25
0.3
0.35

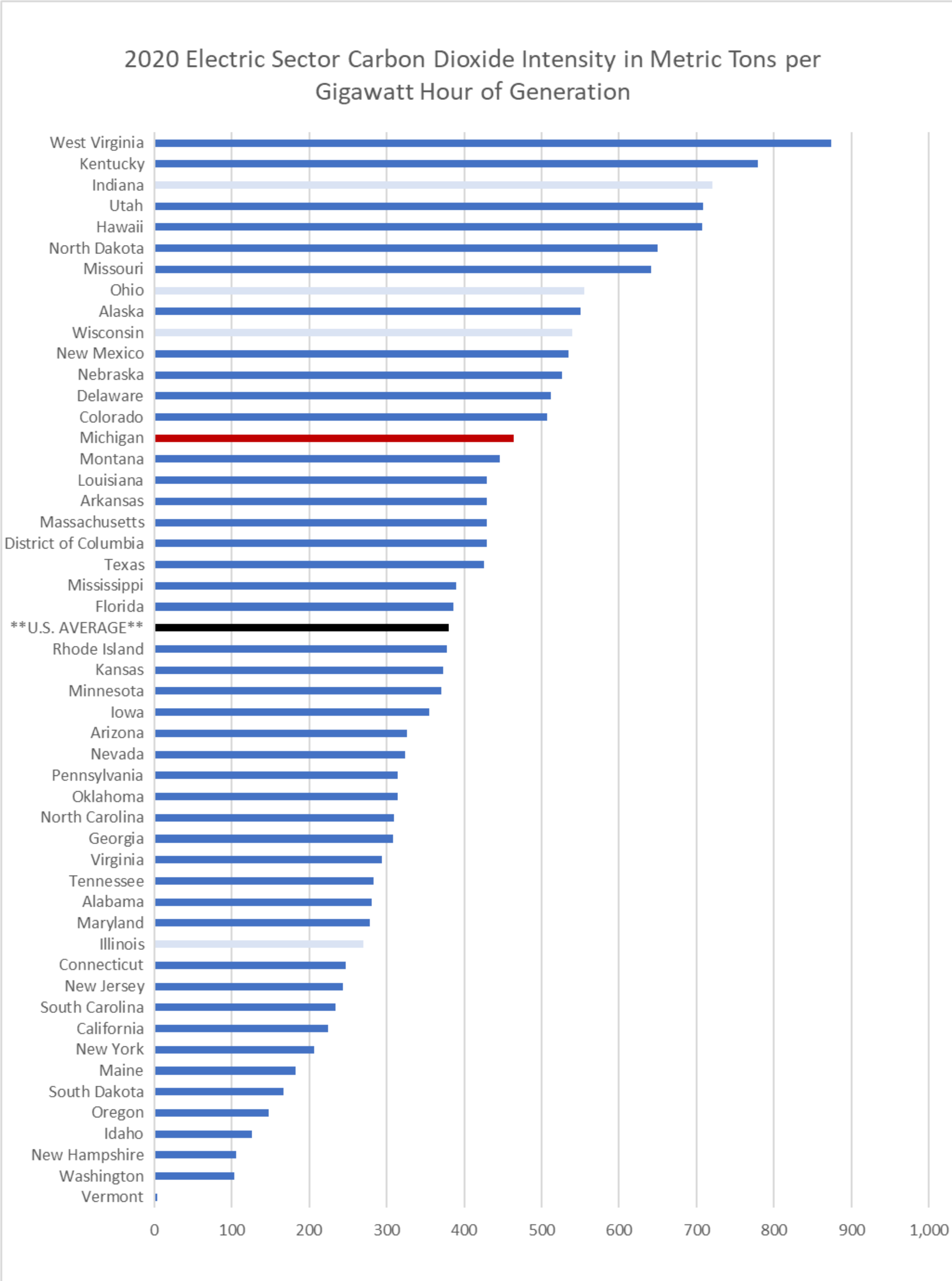

2020/2019 Total Household Energy Expenditure
2020 Average Household Electricty Expenditure
2019 Per Household Non-Electricity Expenditure
Vermont
Massachusetts
New Hampshire
Rhode Island
Alaska
New York
Maine
Pennsylvania
Michigan
New Jersey
Maryland
Hawaii
Virginia
Georgia
Delaware
Alabama
Ohio
Indiana
South Dakota
Montana
Iowa
Kansas
North Dakota
Minnesota
West Virginia
Missouri
Wyoming
California
Arizona
Illinois
South Carolina
Wisconsin
Texas
Mississippi
Nebraska
Tennessee
Kentucky
Nevada
Oklahoma
North Carolina
Arkansas
Idaho
Colorado
Oregon
District of Columbia
Louisiana
Florida
Washington
Utah
New Mexico
$0
$500
$1,000
$1,500
$2,000
$2,500
$3,000
$3,500

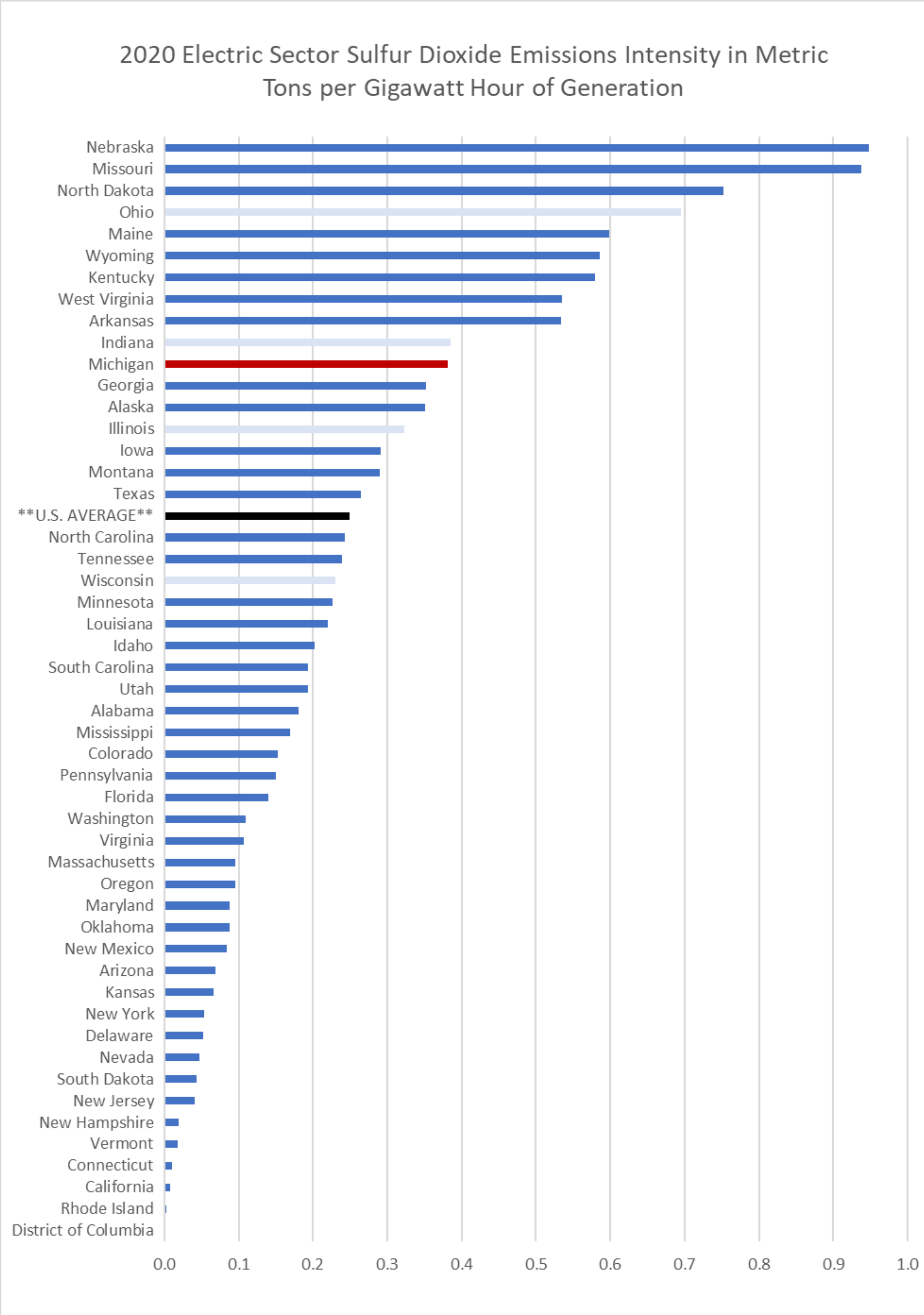

Average Price of Electricity in the Industrial Sector
$0.18
$0.16
$0.14
$0.12
$0.10
$0.08
$0.06
$0.04
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
Michigan - CAGR:0.22%
Wisconsin - CAGR:0.48%
DTE - CAGR:-0.64%
Indiana - CAGR:1.7%
Illinois - CAGR:2.68%
Ohio - CAGR:0.64%

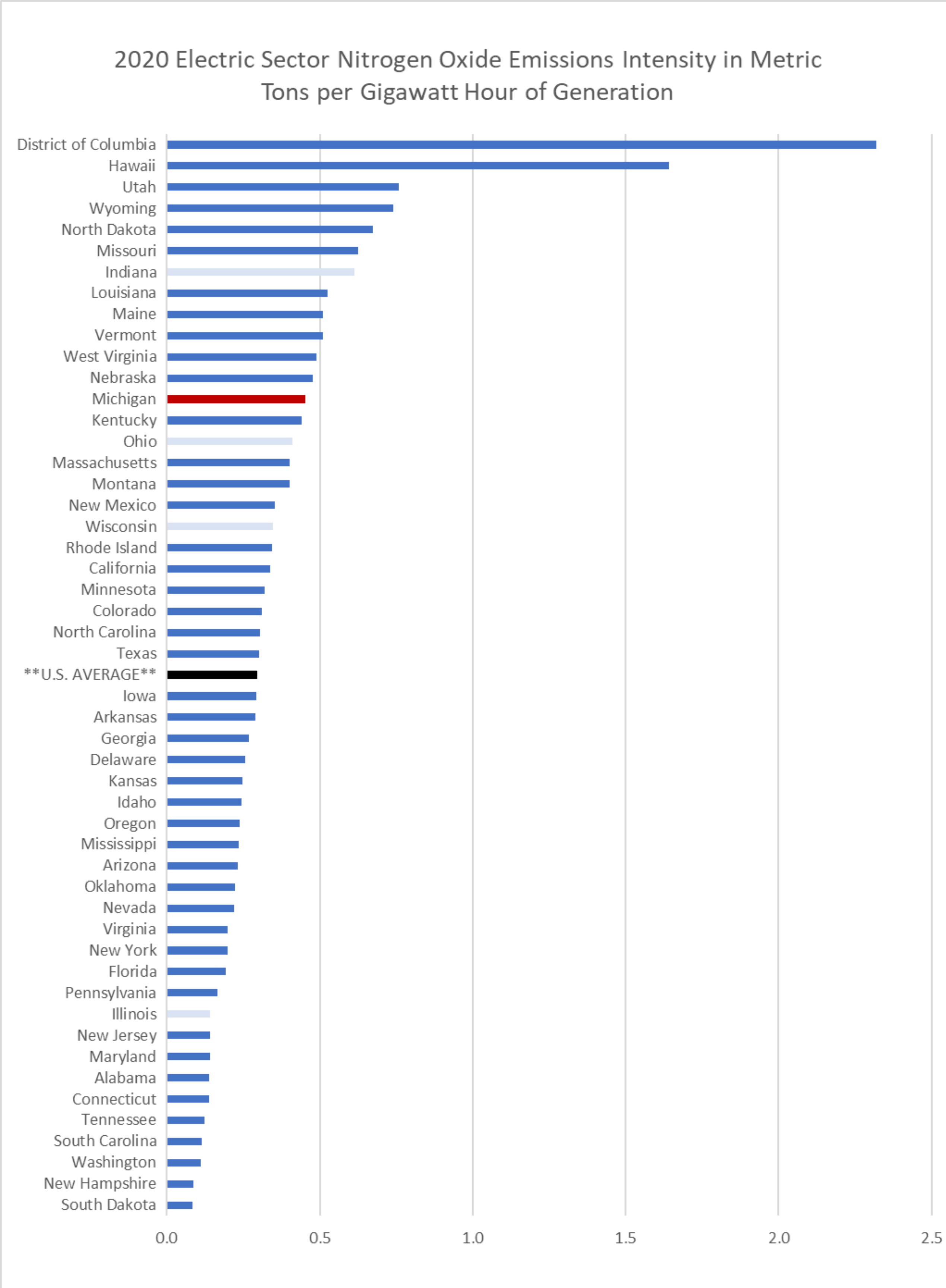

Average Price of Electricity in the Commercial Sector
$0.18
$0.16
$0.14
$0.12
$0.10
$0.08
$0.06
$0.04
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
Michigan - CAGR:1.29%
DTE - CAGR:0.39%
Indiana - CAGR:2.71%
Wisconsin - CAGR:0.43%
Ohio - CAGR:0.35%
Illinois - CAGR:2.18%


Average Price of Electricity in the Residential Sector
$0.18
$0.16
$0.14
$0.12
$0.10
$0.08
$0.06
$0.04
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
DTE - CAGR:1.94%
Michigan - CAGR:2.42%
Wisconsin - CAGR:1.1%
Indiana - CAGR:2.77%
Illinois - CAGR:1.71%
Ohio - CAGR:0.93%


2019/2020 Total Energy Expenditures as a Percentage of Median Household Income
Vermont
Connecticut
Mississippi
Maine
New York
West Virginia
Alaska
Alabama
Rhode Island
Montana
Georgia
Massachusetts
Michigan
Oklahoma
New Hampshire
Ohio
Arkansas
Tennessee
Pennsylvania
Louisiana
Kentucky
South Carolina
Missouri
North Dakota
New Mexico
Indiana
Wyoming
Delaware
Iowa
North Carolina
Nevada
South Dakota
Arizona
Florida
Wisconsin
Kansas
Texas
Illinois
Hawaii
Nebraska
New Jersey
Idaho
Virginia
Minnesota
California
Maryland
Oregon
Colorado
Washington
Utah
District of Columbia
0.0%
0.5%
1.0%
1.5%
2.0%
2.5%
3.0%
3.5%
4.0%
4.5%
5.0%


2020 Electric Sector Carbon Dioxide Intensity in Metric Tons per Gigawatt Hour of Generation
West Virginia
Kentucky
Indiana
Utah
Hawaii
North Dakota
Missouri
Ohio
Alaska
Wisconsin
New Mexico
Nebraska
Delaware
Colorado
Michigan
Montana
Louisiana
Arkansas
Massachusetts
District of Columbia
Texas
Mississippi
Florida
U.S. AVERAGE
Rhode Island
Kansas
Minnesota
Iowa
Arizona
Nevada
Pennsylvania
Oklahoma
North Carolina
Georgia
Virginia
Tennessee
Alabama
Maryland
Illinois
Connecticut
New Jersey
South Carolina
California
New York
Maine
South Dakota
Oregon
Idaho
New Hampshire
Washington
Vermont
0
100
200
300
400
500
600
700
800
900
1,000


2020 Electric Sector Sulfur Dioxide Emissions Intensity in Metric Tons per Gigawatt Hour of Generation
Nebraska
Missouri
North Dakota
Ohio
Maine
Wyoming
Kentucky
West Virginia
Arkansas
Indiana
Michigan
Georgia
Alaska
Illinois
Iowa
Montana
Texas
U.S. AVERAGE
North Carolina
Tennessee
Wisconsin
Minnesota
Louisiana
Idaho
South Carolina
Utah
Alabama
Mississippi
Colorado
Pennsylvania
Florida
Washington
Virginia
Massachusetts
Oregon
Maryland
Oklahoma
New Mexico
Arizona
Kansas
New York
Delaware
Nevada
South Dakota
New Jersey
New Hampshire
Vermont
Connecticut
California
Rhode Island
District of Columbia
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0


2020 Electric Sector Nitrogen Oxide Emissions Intensity in Metric Tons per Gigawatt Hour of Generation
District of Columbia
Hawaii
Utah
Wyoming
North Dakota
Missouri
Indiana
Louisiana
Maine
Vermont
West Virginia
Nebraska
Michigan
Kentucky
Ohio
Massachusetts
Montana
New Mexico
Wisconsin
Rhode Island
California
Minnesota
Colorado
North Carolina
Texas
U.S. AVERAGE
Iowa
Arkansas
Georgia
Delaware
Kansas
Idaho
Oregon
Mississippi
Arizona
Oklahoma
Nevada
Virginia
New York
Florida
Pennsylvania
Illinois
New Jersey
Maryland
Alabama
Connecticut
Tennessee
South Carolina
Washington
New Hampshire
South Dakota
0.0
0.5
1.0
1.5
2.0
2.5

MPSC Case No.:	U-20836
Requestor:	AG
Question No.:	AGDE-1.13
Respondent:	A. Willis
	1 of 1

Question: Provide all analyses prepared by or for the Company that compare its present or proposed rates to other electric distribution companies. Provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Answer: See attachments.

Attachment: U-20836 AGDE-1.13 Spring 2021 Rate Benchmarking
U-20836 AGDE-1.13 Spring 2021 EIA Benchmarking Data

Spring 2021 Electric Rate and Bill Benchmarking – GRC Committee

May ??, 2021

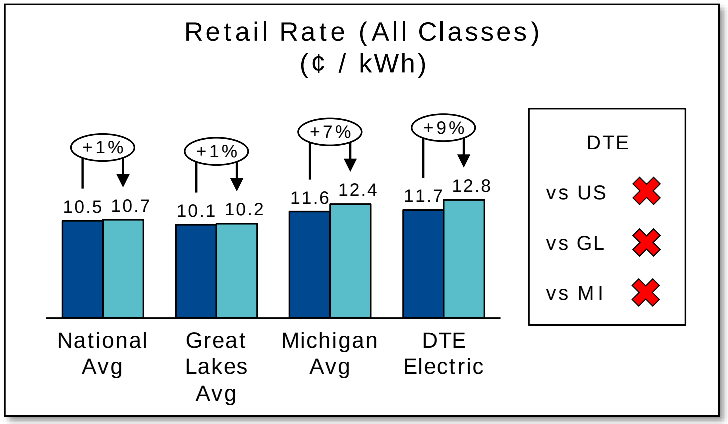
Today we are sharing final 2020 benchmarking results for electric rates and bills

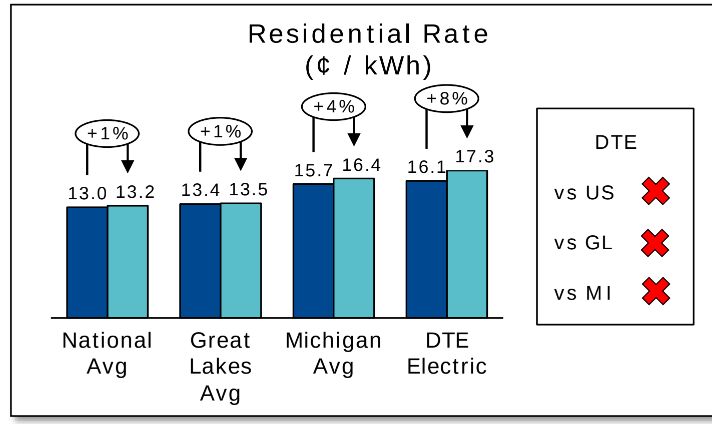
		Distributed 11/30/2020 Fall 2020	**Today's update** Spring 2021
Rates	Electric	• 2020 through July (preliminary) • 2019 full year (final)	• 2020 full year (final)
Residential Bills	Electric	• 2019 full year (final)	• 2020 full year (final)
	Gas	• 2019 full year (final)	• NA

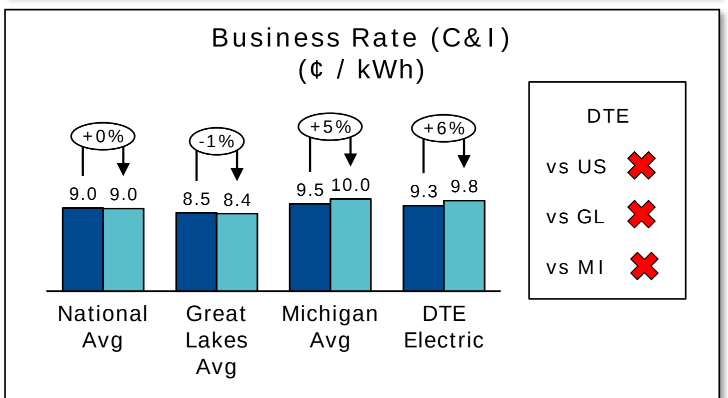
Note: Preliminary benchmarking refers to results based on the sum of monthly data (from EIA form 861M). Final data refers to results from reconciled full-year data (from EIA form 861 for electric and EIA Form 176 for gas)

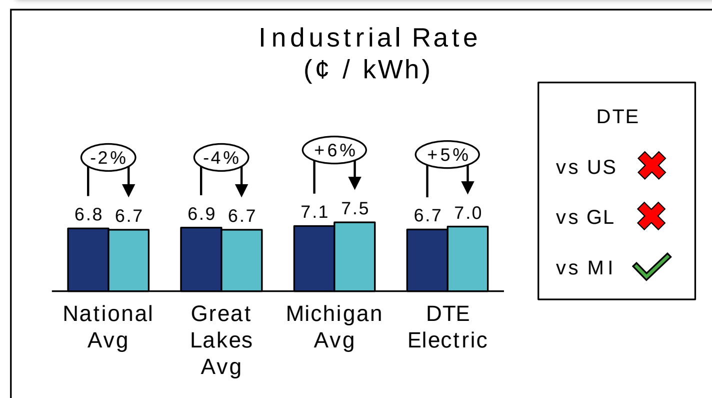
From 2019 to 2020, DTE Electric business rates increased while regional and national averages decreased or remained flat

2019
2020





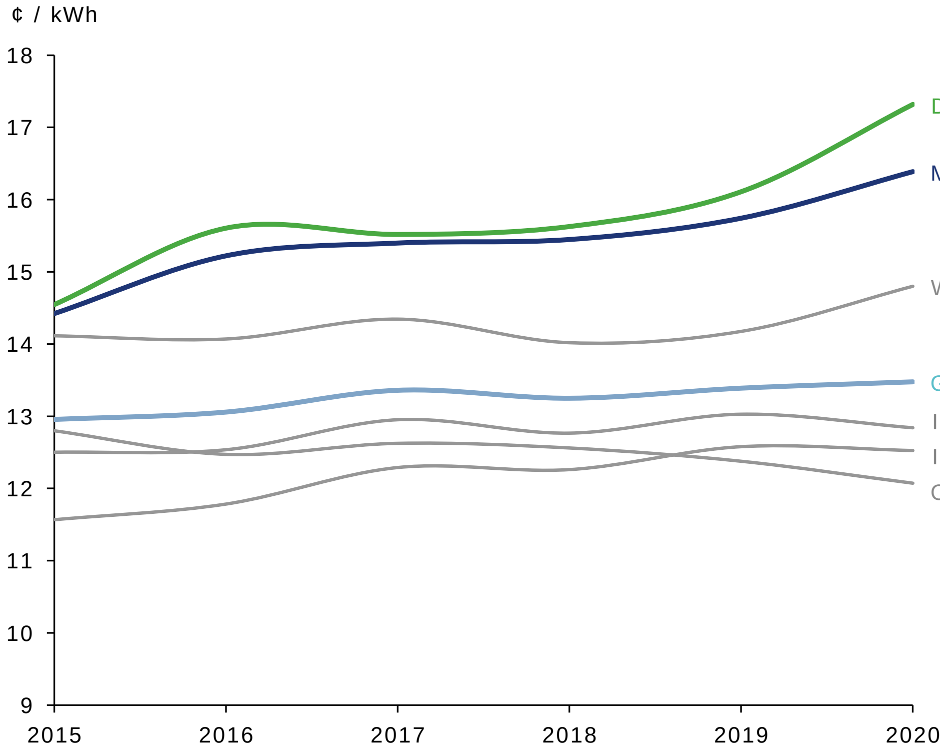




DTE

Source: EIA form 861 and 861M

Looking over the long-term, DTE and Michigan have the highest residential 5-year rate growth in the region



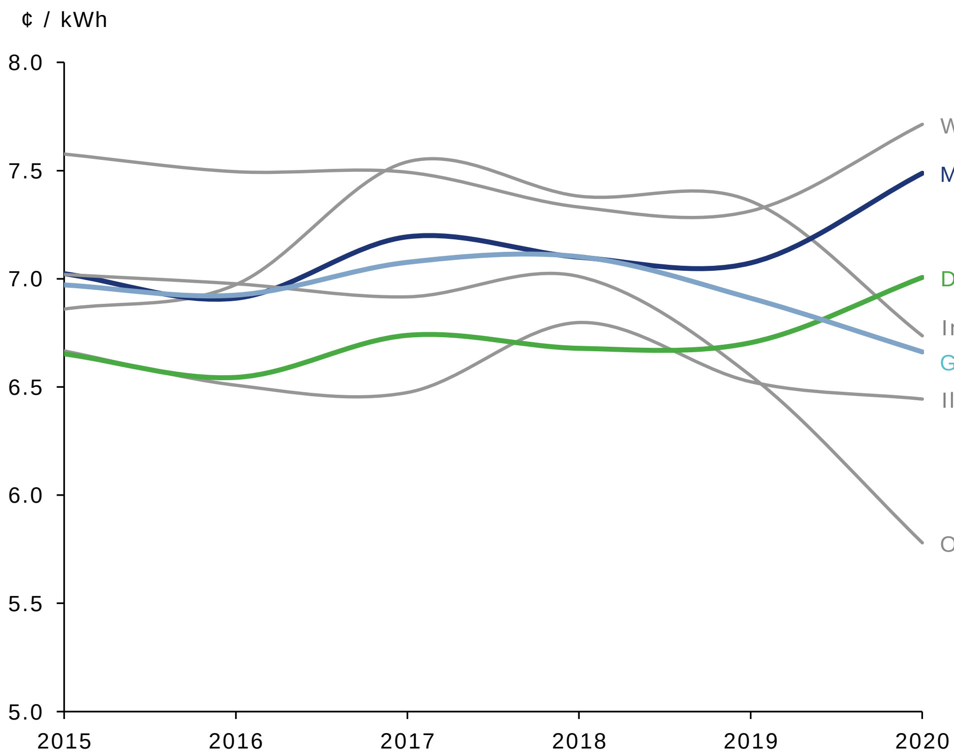
Average annual growth

	1-year	3-year	5-year
DTE	7.5 %	3.7 %	3.5 %
Michigan	4.1 %	2.1 %	2.6 %
Wisconsin	4.4%	1.0%	1.0%
Great Lakes avg.	0.7 %	0.3 %	0.8 %
Illinois	-1.4%	-0.3%	0.5%
Indiana	-0.4%	0.6%	1.6%
Ohio	-2.5%	-1.5%	-1.2%

Source: EIA form 861M and 861

Michigan and DTE have the highest industrial rate growth over 5 years

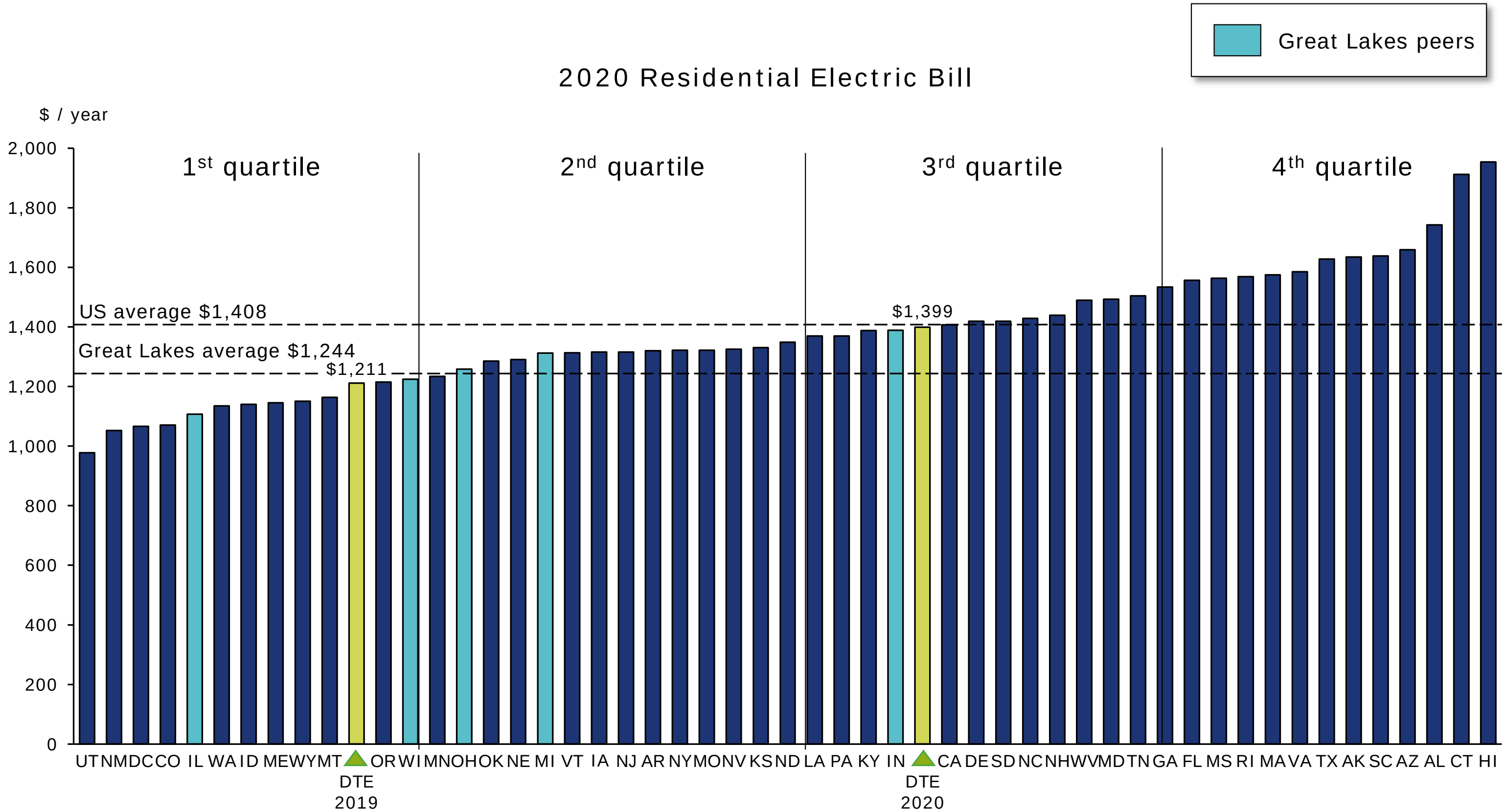
Industrial Electric Rate



Average annual growth

	1-year	3-year	5-year
Wisconsin	5.5%	1.0%	0.4%
Michigan	5.9 %	1.3 %	1.3 %
DTE	4.5 %	1.3 %	$\boxed{1.0\ \%}$
Indiana	-8.5%	-3.7%	-0.4%
Great Lakes avg.	-3.6 %	-2.0 %	-0.9 %
Illinois	-1.2%	-0.2%	-0.7%
Ohio	-11.8%	-5.8%	-3.8%

DTE average electric bills increased 15% from 2019 and moved into the 3rd quartile across the US

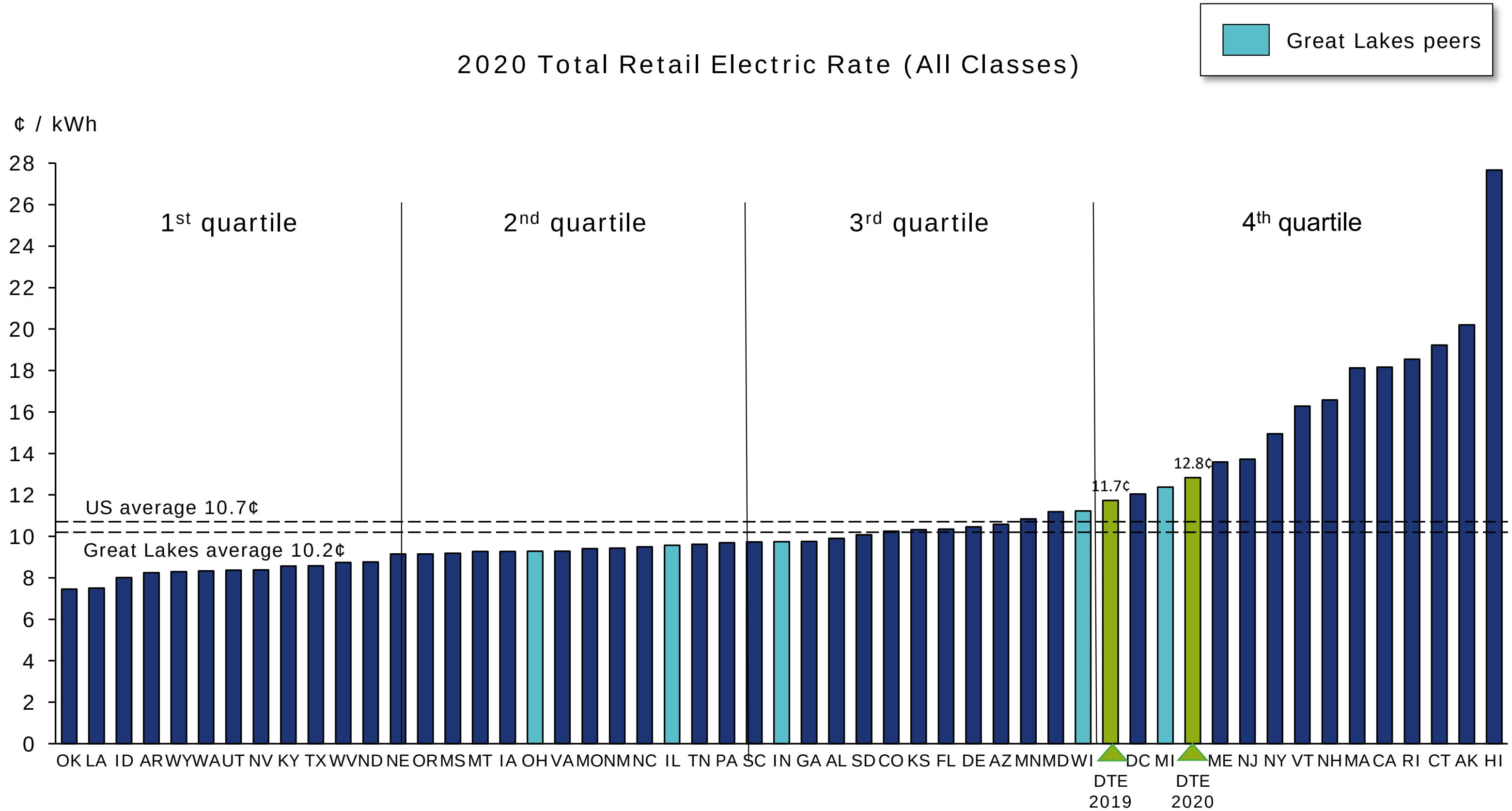


DTE

Source: EIA form 861M

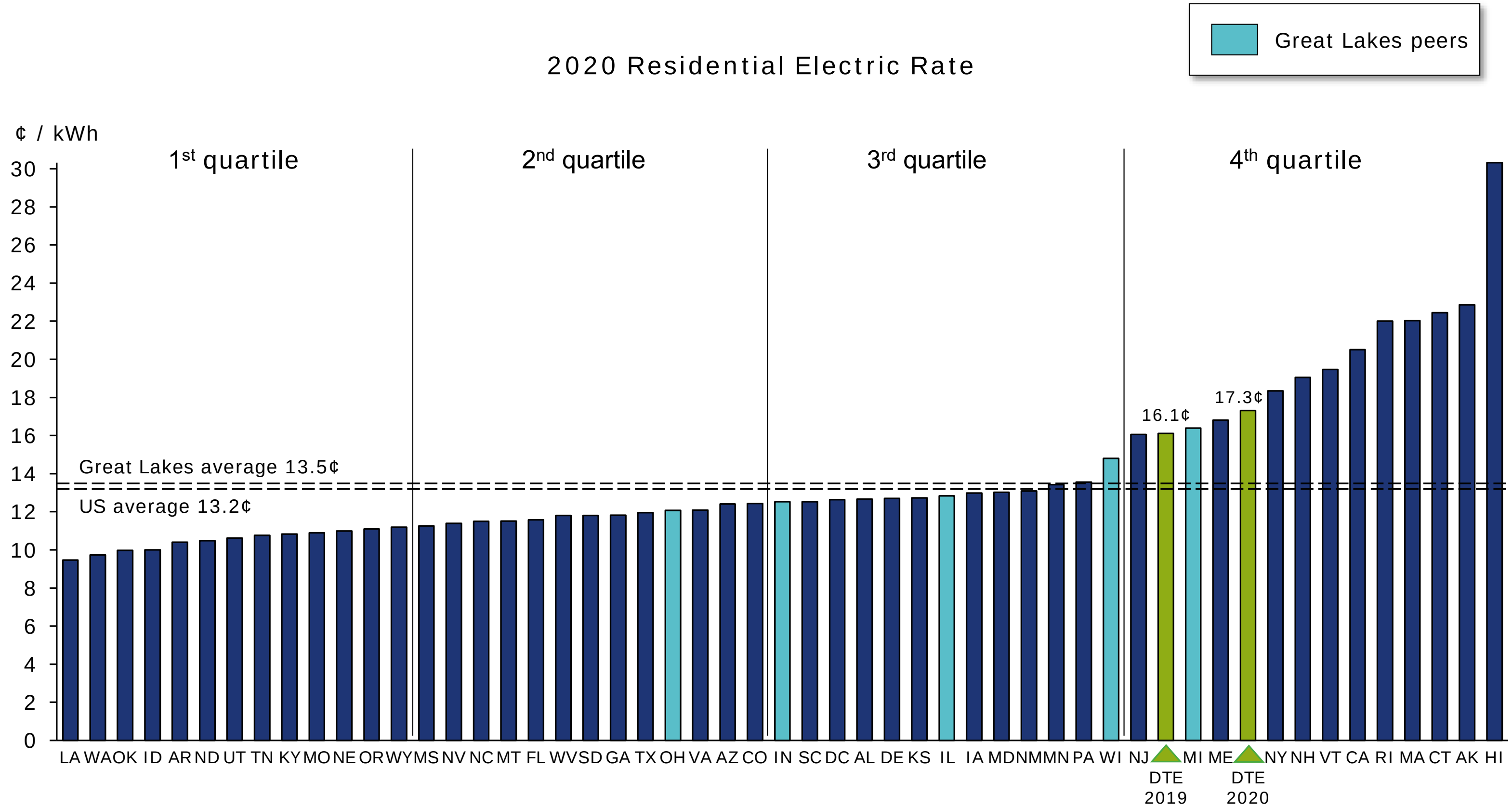
Appendix

In 2020, Michigan and DTE average total retail rates were 16% and 20%, respectively, above the US average and 21% and 25%, respectively, above the regional average



Source: EIA form 861M

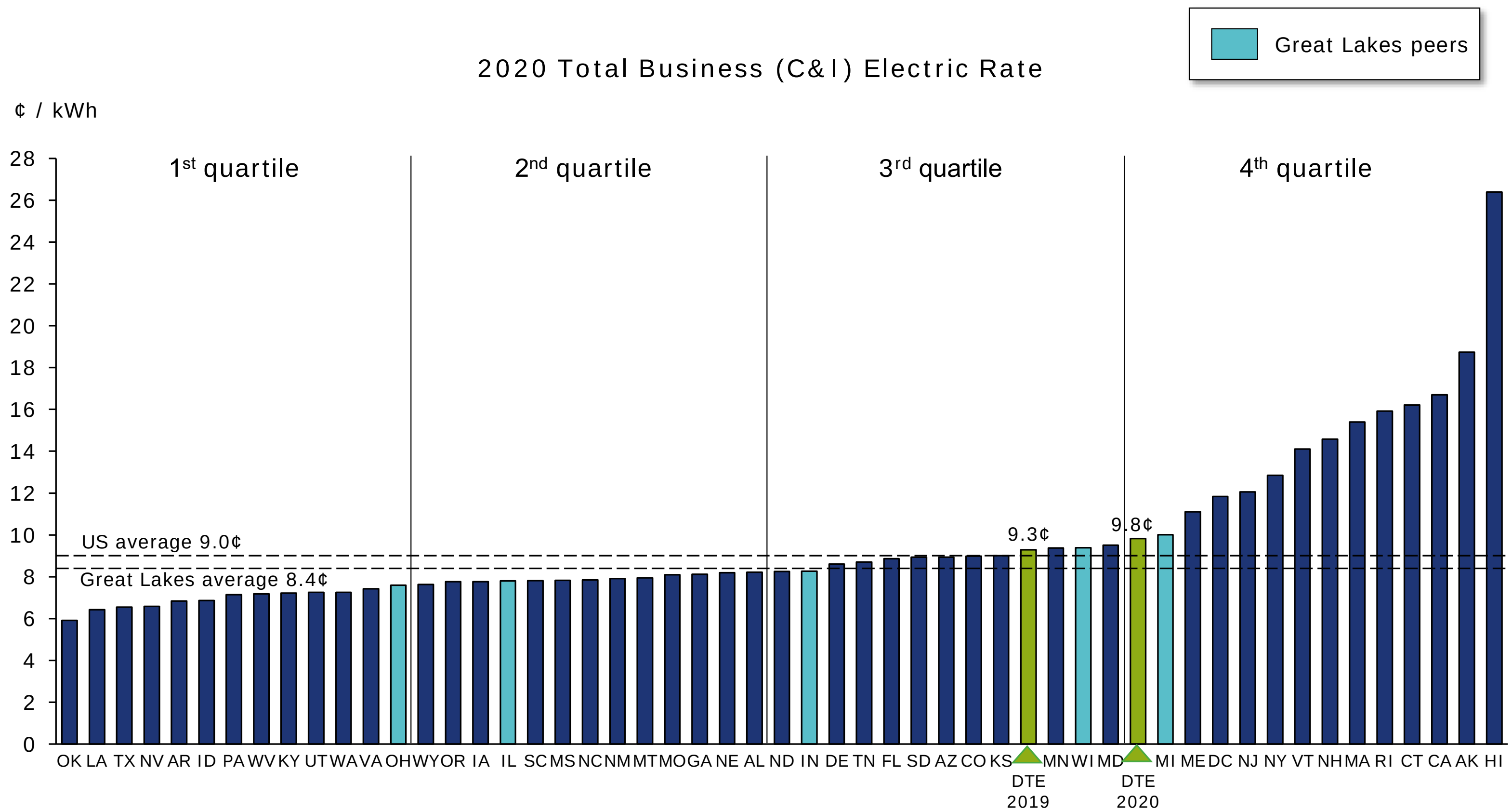
Michigan and DTE average residential rates were 24% and 31% above the US average, respectively; and 22% and 28%, respectively, above the regional average



Source: EIA form 861M

Michigan and DTE average business rates were 11% and 9% above the US average, respectively; and 19% and 17%, respectively, above the regional average

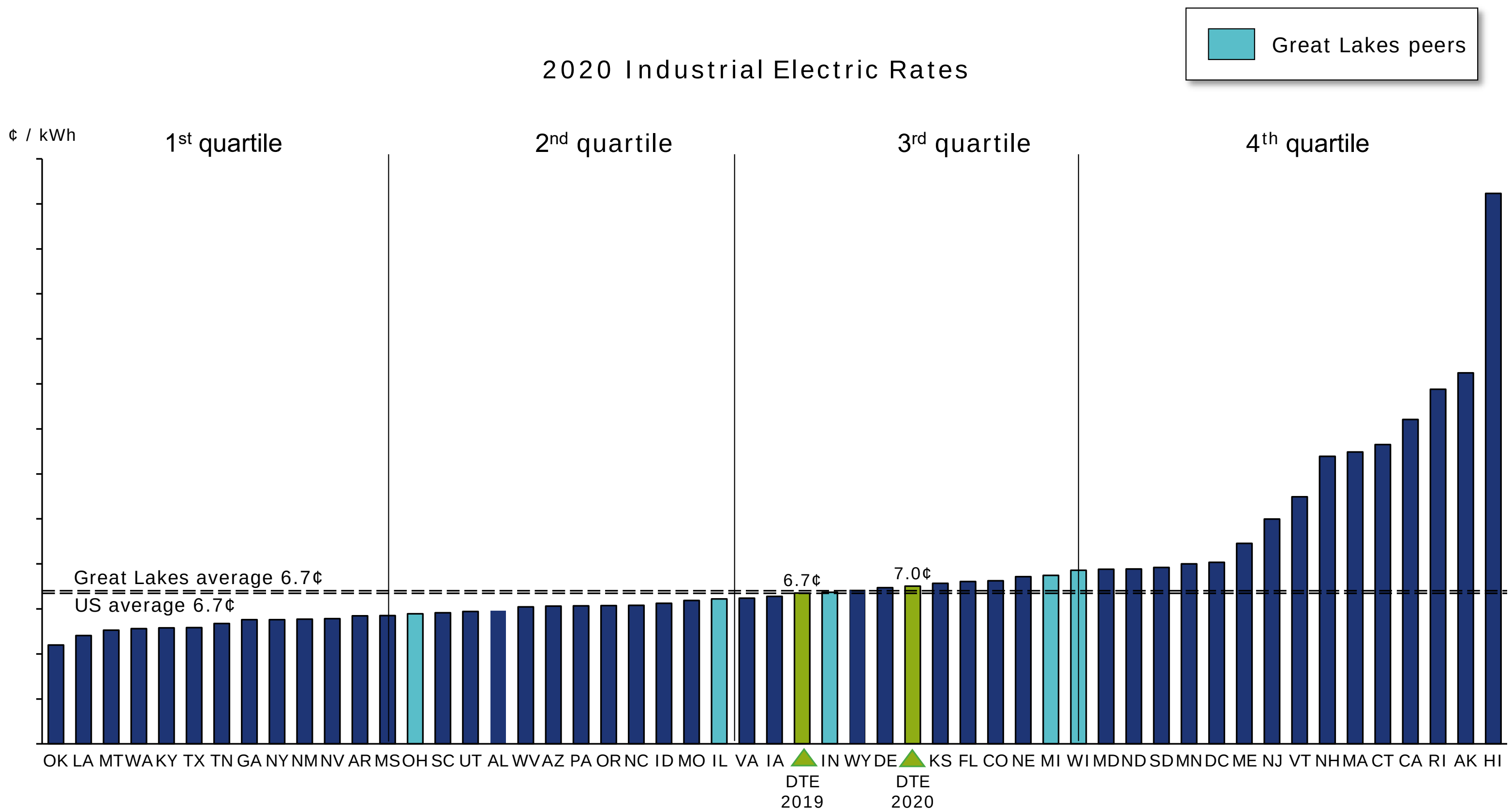
2020 Total Business (C&I) Electric Rate



DTE

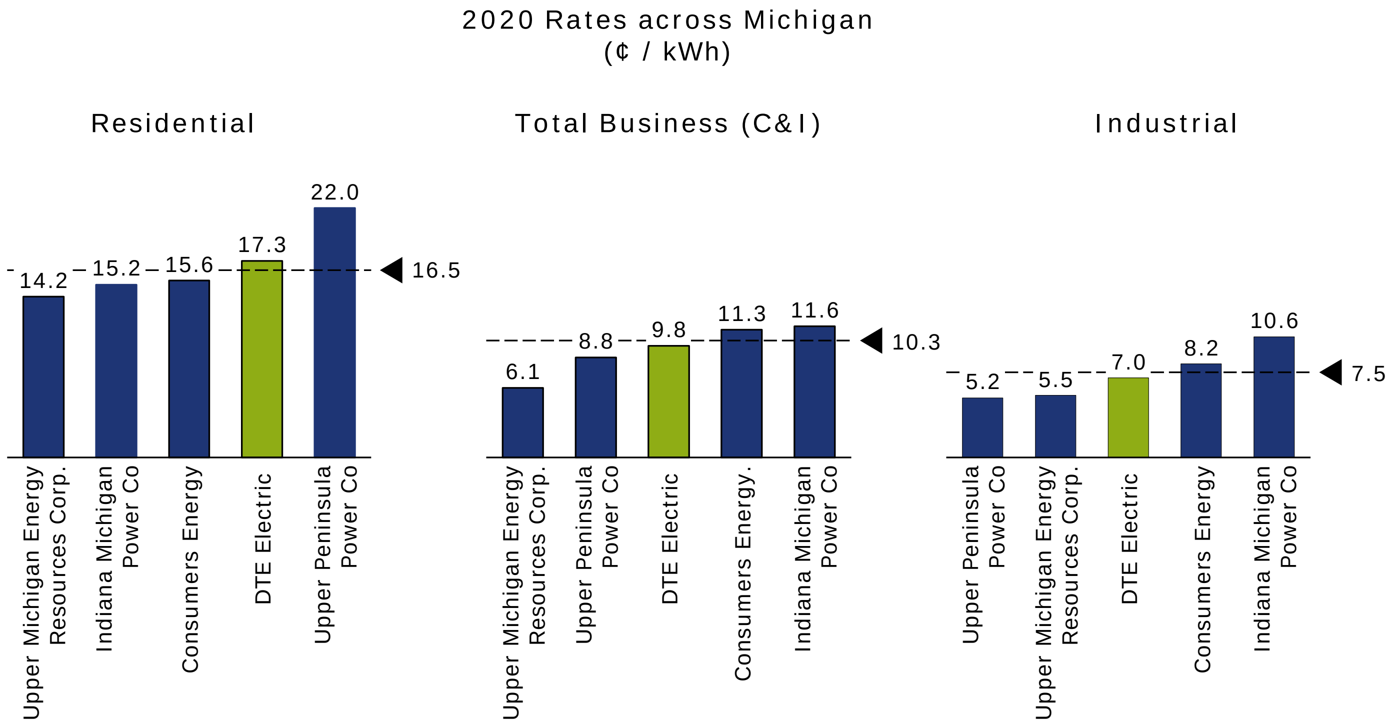
Source: EIA form 861M

Michigan average industrial rates were 12% above the US average while DTE industrial rates were 5% above the US and the region average



Source: EIA form 861M

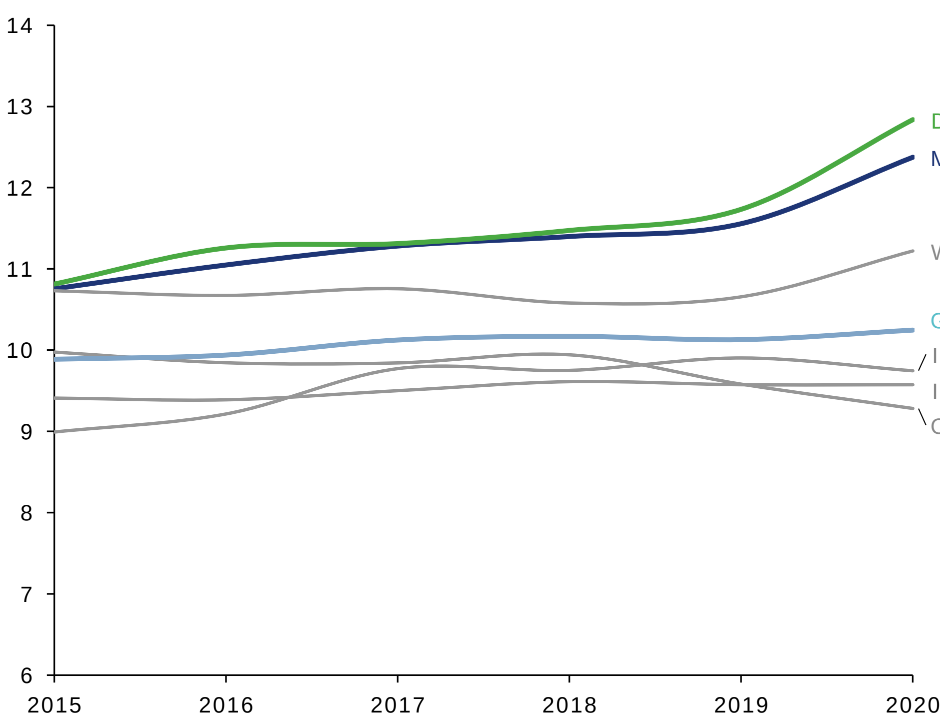
DTE Electric's 2020 business and industrial rates were below the Michigan average



DTE business and industrial rates are below the Michigan average

Source: EIA form 861M

The changes in DTE Electric retail rates compare unfavorably to our regional average over the 1, 3, and 5 year period

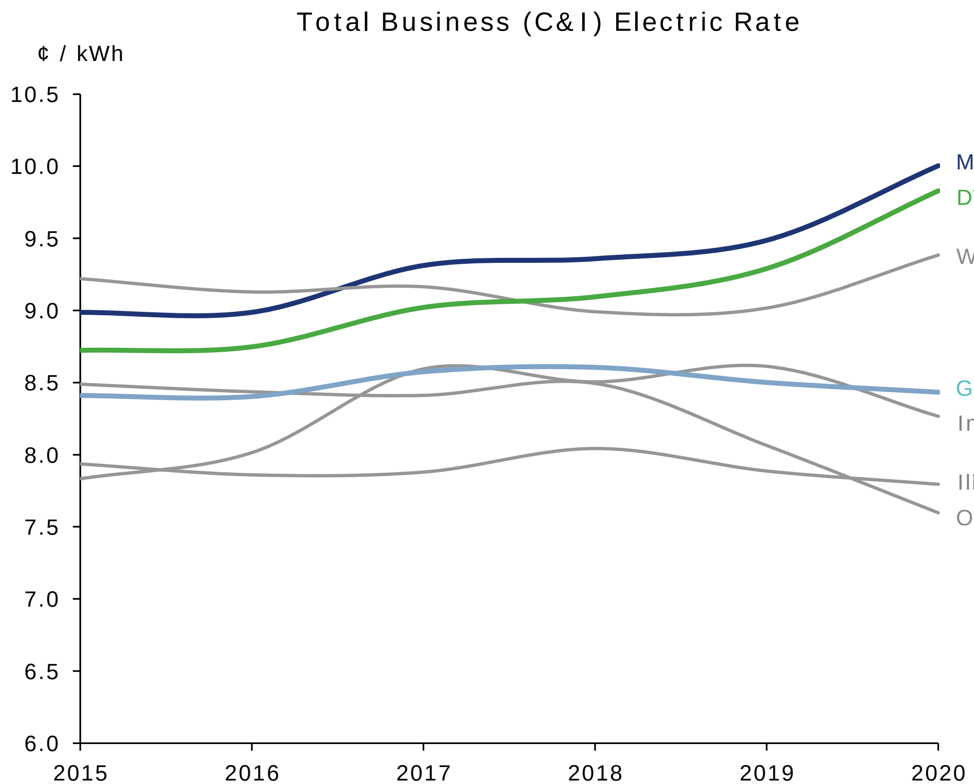


Average annual growth

	1-year	3-year	5-year
DTE	9.4 %	4.3 %	3.5 %
Michigan	7.1 %	3.1 %	2.8 %
Wisconsin	5.3%	1.4%	0.9%
Great Lakes avg.	1.2 %	0.4 %	0.7 %
Indiana	-1.6%	-0.1%	1.6%
Illinois	0%	0.3%	0.3%
Ohio	-3.1%	-1.9%	-1.4%

Source: EIA form 861M and 861

DTE total business rate changes compare unfavorably to the regional average over 1, 3, and 5 year periods



Average annual growth

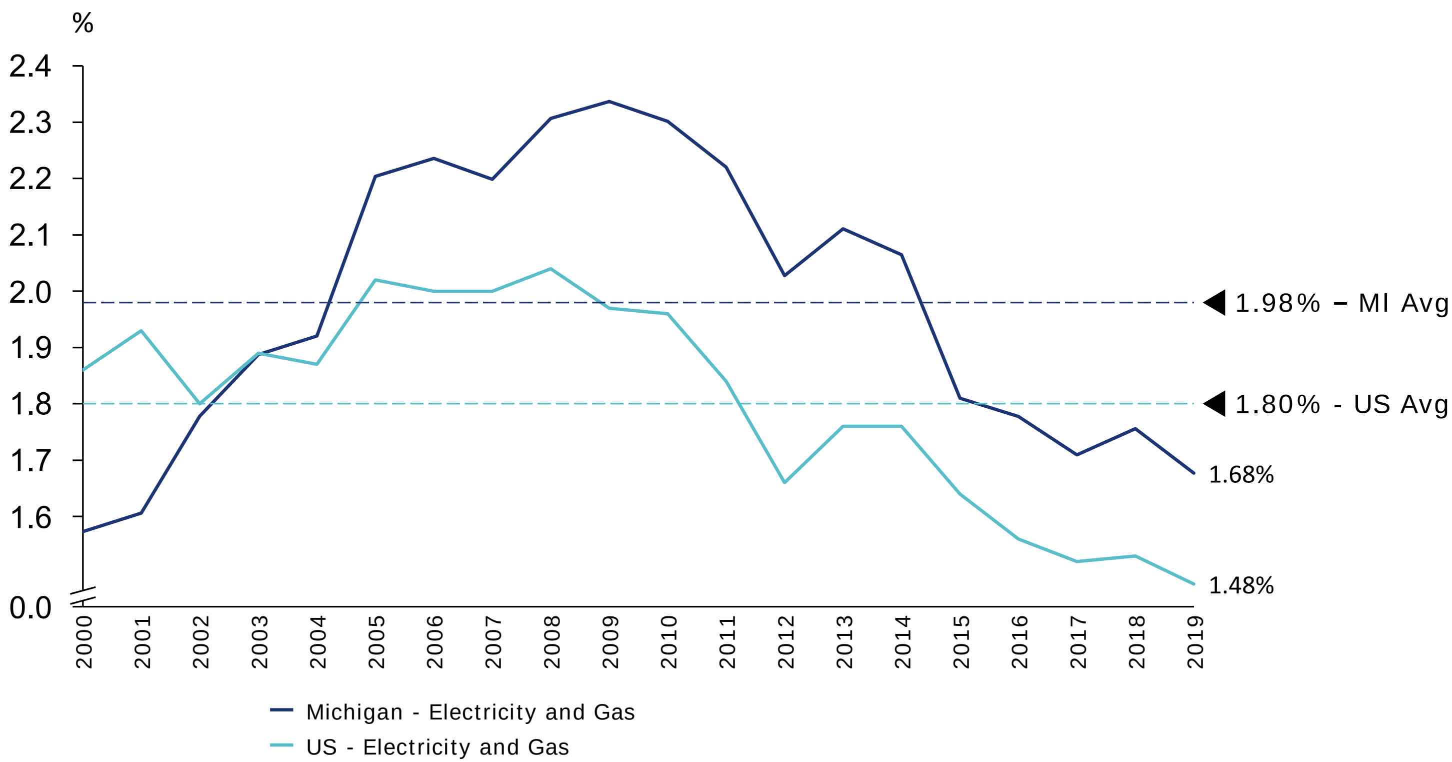
	1-year	3-year	5-year
Michigan	5.4 %	2.4 %	2.2 %
DTE	5.8 %	2.9 %	2.4 %
Wisconsin	4.1%	0.8%	0.4%
Great Lakes avg.	-0.8 %	-0.6 %	0.1 %
Indiana	-4.0%	-1.3%	1.1%
Illinois	-1.2%	-0.4%	-0.4%
Ohio	-5.8%	-3.3%	-2.2%

DTE

Source: EIA form 861M and 861

Michigan residential electric and gas utility expenditures are low relative to the recent past and have been tracking the national average

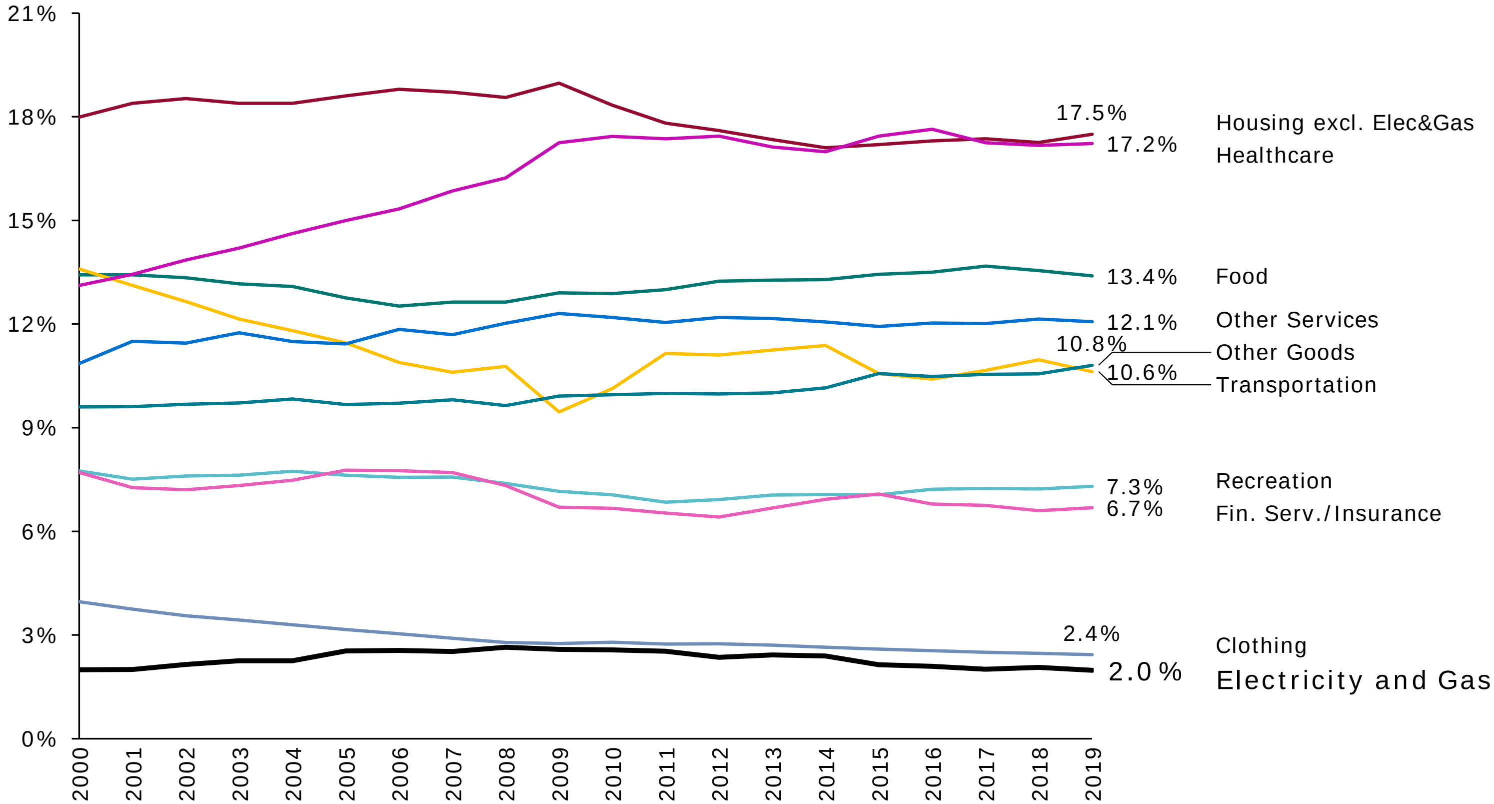
Michigan and US utility spending as a percent of disposable income over time



- BEA Table 2.1. and EIA
- BEA SAINC1 Personal Income Summary: Personal Income, Population, Per Capita Personal Income

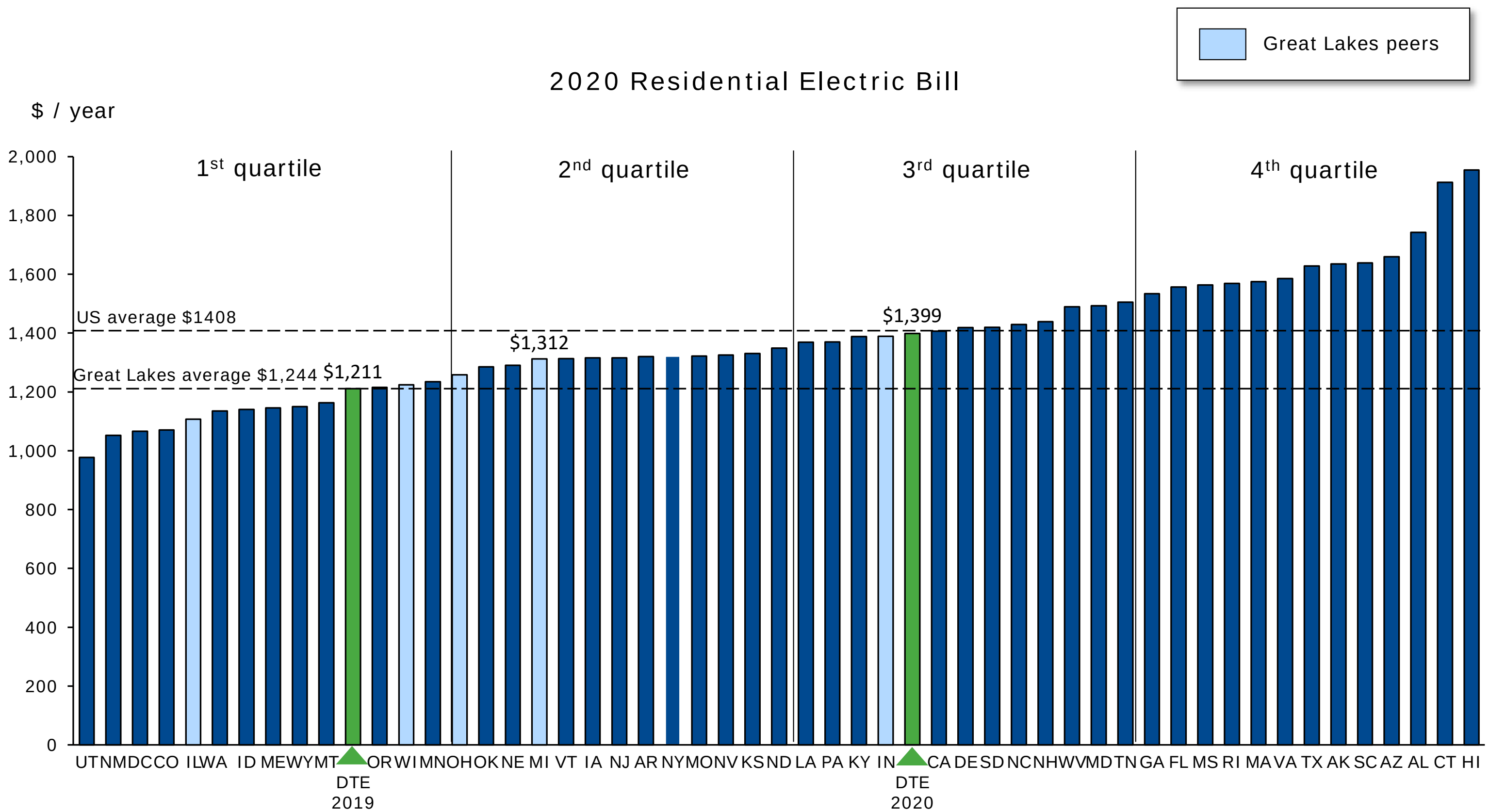
Within Michigan, residential electric and gas utility expenditures remain small relative to other typical categories of household spend

Michigan percentage of personal consumption over time



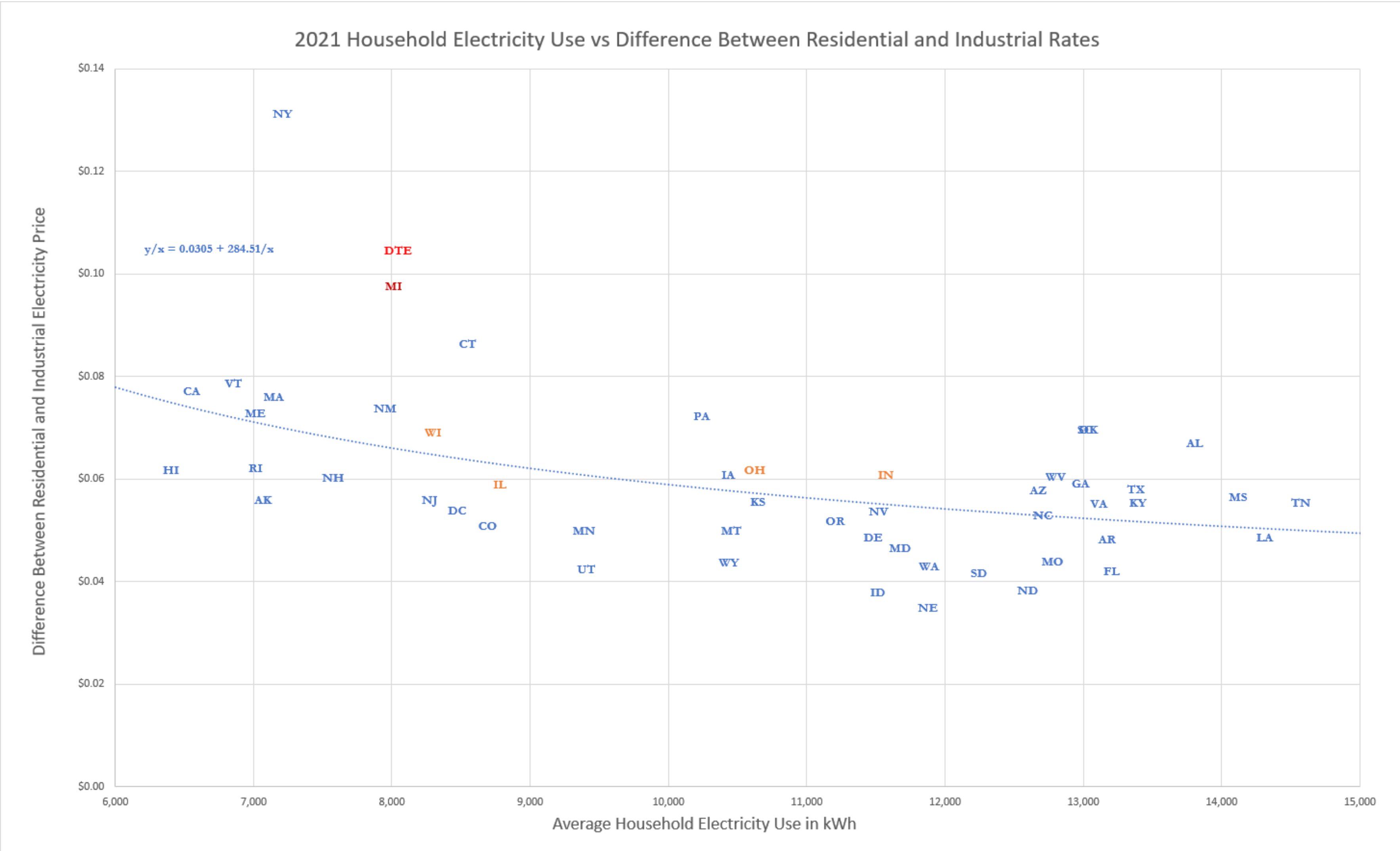
Source: BEA SAEXP1 Total personal consumption expenditures (PCE) by state (Michigan), EIA for Electric and Gas

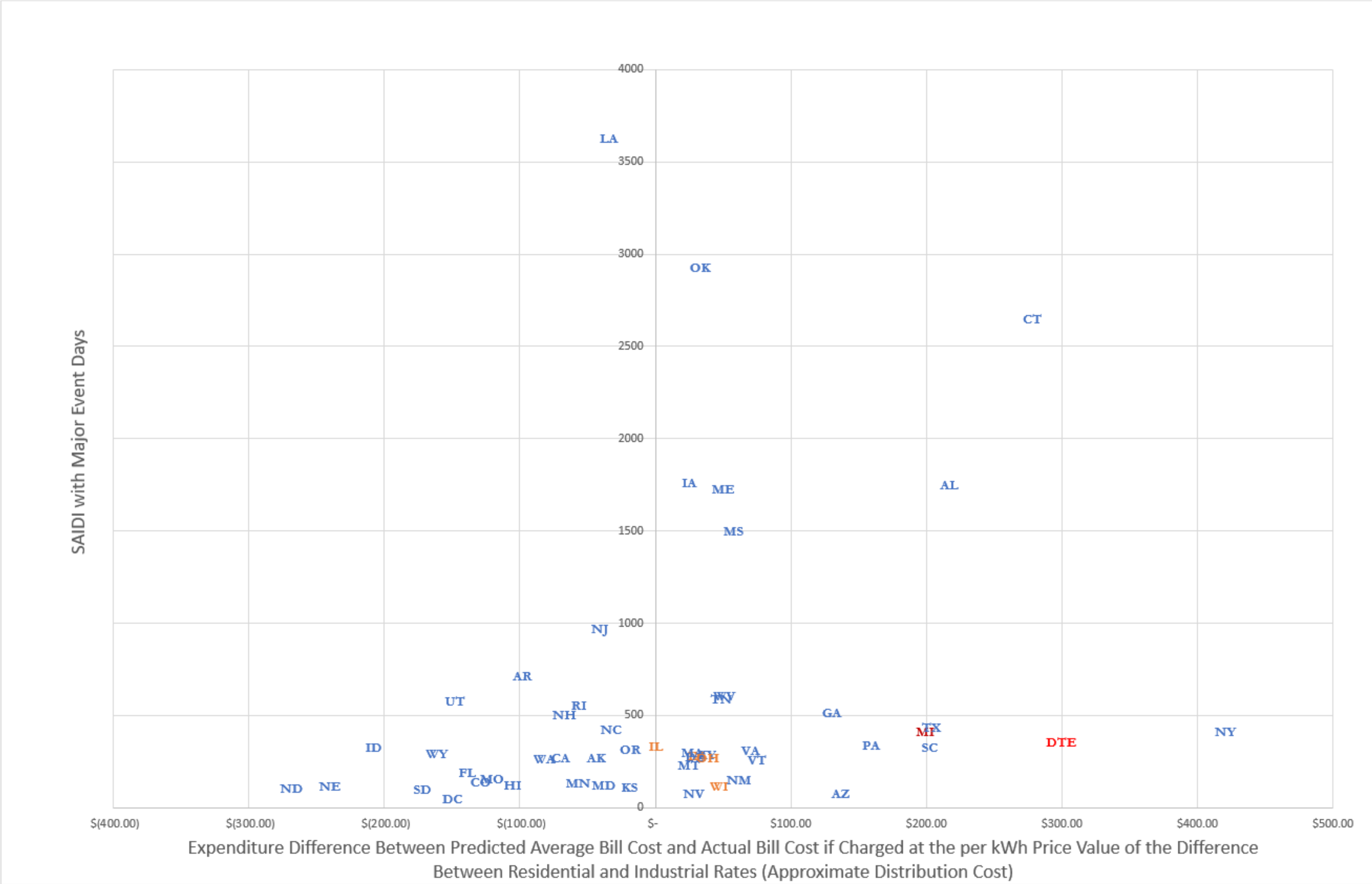
In 2020, DTE residential electric bills were 1% below and Michigan bills were 7% below the US average

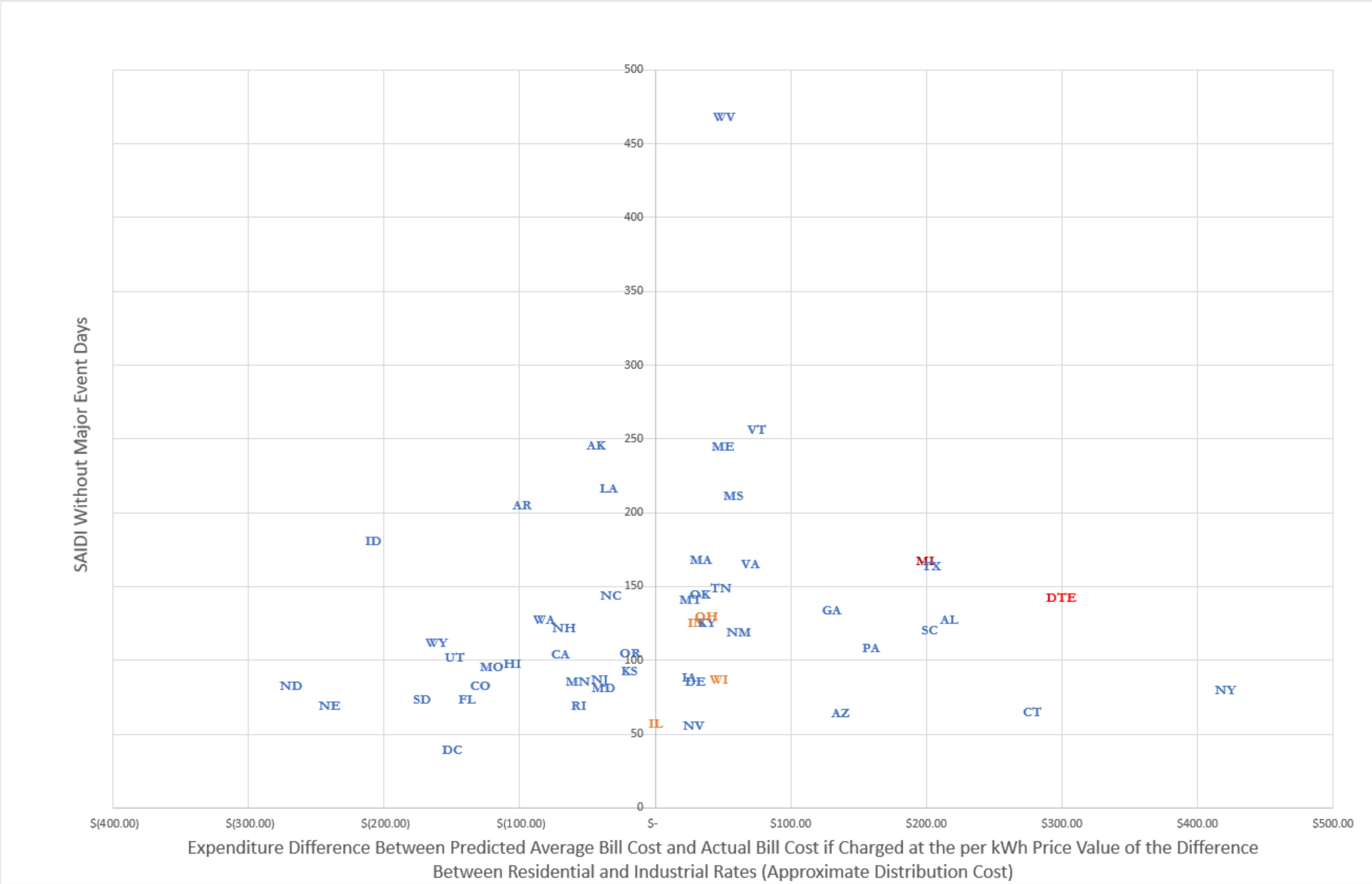


Source: EIA form 861


2021 Household Electricity Use vs Household Expenditures on Electricity if Electricity is Priced at the DIfference Between Industrial and Residential Electricity Prices
Household Expenditures on Electricity if Priced at the Difference Between Residential and Industrial Rates
Average Household Electricity Use in kWh
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$-
6,000
7,000
8,000
9,000
10,000
11,000
12,000
13,000
14,000
15,000
y = 0.0305x + 284.51
NY
DTE
MI
CT
PA
IN
OH
IA
NV
KS
OR
DE
MD
NM
WI
VT
MA
CA
ME
IL
MT
WA
SD
ND
NH
NJ
DC
CO
MN
WY
RI
ID
NE
HI
AK
UT
OK
SC
AL
MS
TN
WV
GA
TX
KY
AZ
VA
LA
NC
AR
MO
FL


2021 Household Electricity Use vs Difference Between Residential and Industrial Rates
Difference Between Residential and Industrial Electricity Price
Average Household Electricity Use in kWh
y/x = 0.0305 + 284.51/x
$0.14
$0.12
$0.10
$0.08
$0.06
$0.04
$0.02
$0.00
6,000
7,000
8,000
9,000
10,000
11,000
12,000
13,000
14,000
15,000
NY
DTE
MI
CT
CA
VT
MA
ME
NM
WI
PA
AL
HI
RI
NH
IA
OH
IN
WV
GA
TX
AZ
MS
TN
AK
NJ
IL
KS
VA
KY
DC
NV
NC
CO
OR
MN
MT
DE
AR
LA
MD
MO
WY
WA
FL
UT
SD
ID
ND
NE


SAIDI with Major Event Days
Expenditure Difference Between Predicted Average Bill Cost and Actual Bill Cost if Charged at the per kWh Price Value of the Difference Between Residential and Industrial Rates (Approximate Distribution Cost)
4000
3500
3000
2500
2000
1500
1000
500
0
$(400.00)
$(300.00)
$(200.00)
$(100.00)
$-
$100.00
$200.00
$300.00
$400.00
$500.00
LA
OK
CT
IA
ME
AL
MS
NJ
AR
UT
RI
NH
NC
GA
TX
MI
DTE
NY
ID
WY
IL
PA
SC
OR
VA
VT
WA
CA
AK
FL
CO
MO
HI
MN
MD
KS
NM
WI
ND
NE
SD
DC
NV
AZ
MT


SAIDI Without Major Event Days
500
450
400
350
300
250
200
150
100
50
0
$(400.00)
$(300.00)
$(200.00)
$(100.00)
$-
$100.00
$200.00
$300.00
$400.00
$500.00
WV
VT
AK
ME
LA
MS
AR
ID
MA
VA
MI
TX
DTE
NC
TN
OK
MT
GA
OH
AL
WA
IN
KY
NH
SC
NM
WY
PA
UT
CA
OR
MO
HI
KS
IA
WI
DE
ND
MN
NJ
CO
MD
NY
SD
FL
NE
RI
CT
AZ
IL
NV
DC
Expenditure Difference Between Predicted Average Bill Cost and Actual Bill Cost if Charged at the per kWh Price Value of the Difference Between Residential and Industrial Rates (Approximate Distribution Cost)

MPSC Case No.:	U-20836
Requestor:	EIB
Question No.:	EIBDE-1.2a
Respondent:	B. Burns
	1 of 1

Question: See testimony of Benjamin J. H. Burns, p. BJHB-17, specifically, Figure 1.

a. Please provide the data for this figure as an Excel spreadsheet.

Answer: Please see attached, tab 2a.

Attachment: *U-20836 EIBDE-1.2a-c EV Forecasts.xlsx*

MPSC Case No.:	U-20836
Requestor:	EIB
Question No.:	EIBDE-1.2b
Respondent:	B. Burns
	1 of 1

Question: See testimony of Benjamin J. H. Burns, p. BJHB-17, specifically, Figure 1.

b. Please describe the method used to develop the projection presented in Figure 1. If based on a sales forecast and fleet turnover model, please provide those assumptions and calculations.

Answer: A Michigan forecast was developed by averaging the following three forecasts as shown in the attachment, tab 2b:

1. National forecast from Bloomberg New Energy Finance (BNEF) from June 2021 and applied to Michigan using a calculated Michigan discount rate compared to national EV sales (based on 2020 percent of EV sales in Michigan and nationally of 1.1% and 2.4%, respectively, and ramping to equal percent of sales by 2030)
2. National forecast from Automotive Communities Partnership (ACP) from June 2021 and applied to Michigan using the same methodology
3. Michigan-specific forecast from IHS from December 2019

From there, DTE Electric then projected those sales into DTE's electric service territory by ramping down from 71% in 2020 (actual value) to 50% by 2030 (projected value).

For a cumulative volume, DTE Electric adds the sales year over year, but subtracts the sales from 10 years prior (assumes a 10-year life for calculating turnover).

Attachment: *U-20836 EIBDE-1.2a-c EV Forecasts.xlsx*

MPSC Case No.:	U-20836
Requestor:	EIB
Question No.:	EIBDE-1.2c
Respondent:	B. Burns
	1 of 1

Question: See testimony of Benjamin J. H. Burns, p. BJHB-17, specifically, Figure 1.

c. Has DTE Electric developed this or other projections by vehicle class? If so, please provide those.

Answer: Yes, the Company also projected fleet sales in four categories (medium-duty, heavy-duty, transit buses, and school buses) as shown in tab "2c" of the attachment (but not included in BJHB-17, Figure 1).

Attachment: *U-20836 EIBDE-1.2a-c EV Forecasts.xlsx*

MPSC Case No.:	U-20836
Requestor:	EIB
Question No.:	EIBDE-1.2d
Respondent:	B. Burns
	1 of 1

Question: See testimony of Benjamin J. H. Burns, p. BJHB-17, specifically, Figure 1.

d. Has DTE Electric developed projections of the charging infrastructure that will be necessary to support the EV population that DTE Electric projects in its service territory? If so, please provide those.

Answer: Yes. DTE Electric utilizes the Alternative Fuels Data Center Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite. See page 40, Table 7 of my testimony for a forecast of the charging infrastructure needed in 2023 and the assumptions used (footnote 48).

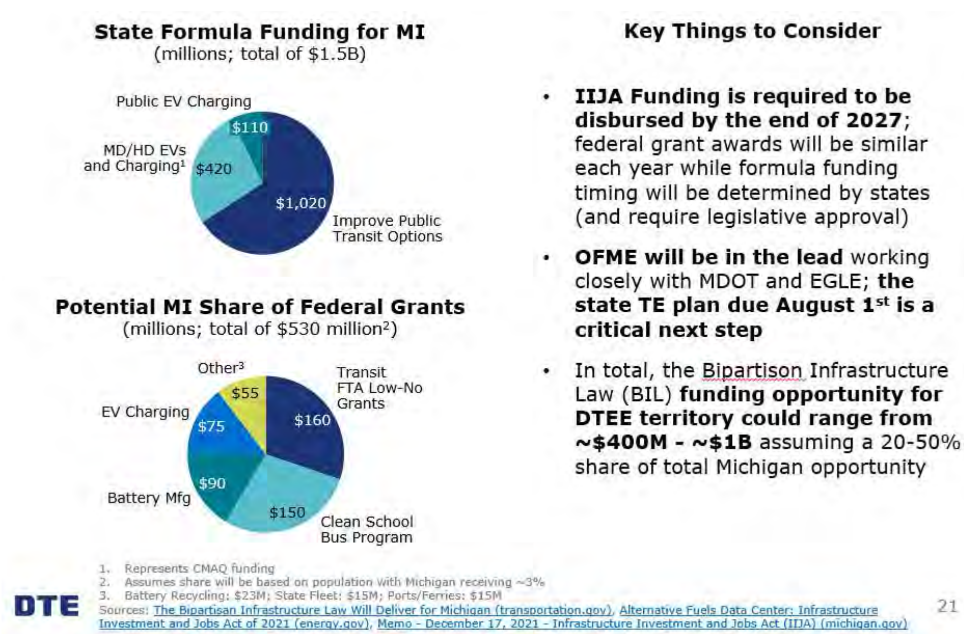
Attachment: *None*

MPSC Case No.:	U-20836
Requestor:	EIB
Question No.:	EIBDE-1.11a
Respondent:	B. Burns
	1 of 1

Question: Apparently, subsequent to DTE Electric's preparation of testimony for this case, Federal and State governments have announced a number of initiatives to plan, finance, and implement electric vehicle charging infrastructure.

a. Has DTE Electric analyzed those announcements? If so, please provide those analyses.

Answer: DTE has analyzed the Bipartisan Infrastructure Law (BIL) to understand the potential size of the funding available for Michigan and DTE Electric territory (see screenshot below of compiled analysis gathered for Charging Forward stakeholder meeting on March 21st). DTE is working closely with the State offices to ensure that the Company's proposed pilots and BIL funding are complementary to each other.



Attachment: *None*

MPSC Case No.:	U-20836
Requestor:	EIB
Question No.:	EIBDE-1.11b
Respondent:	B. Burns
	1 of 1

Question: Apparently, subsequent to DTE Electric's preparation of testimony for this case, Federal and State governments have announced a number of initiatives to plan, finance, and implement electric vehicle charging infrastructure.

b. Do the various announcements have any implications for DTE Electric's projections or proposals in this case? If so, please explain those implications.

Answer: Not at this time, since the current proposal's test period is only through October 31, 2023. DTE Electric has always intended for Charging Forward to be complementary to other sources of funding, similar to how the Company has partnered with EGLE to deploy the VW Settlement Funds for DCFCs. However, if utility cost-share is expected as part of fund disbursement, the Company anticipates needing to scale the volume of make-ready rebates up (and potentially decrease the size of the rebate, depending on the BIL cost-share portion).

Attachment: *None*

MPSC Case No.:	U-20836
Requestor:	EIB
Question No.:	EIBDE-1.11c
Respondent:	B. Burns
	1 of 1

Question: Apparently, subsequent to DTE Electric's preparation of testimony for this case, Federal and State governments have announced a number of initiatives to plan, finance, and implement electric vehicle charging infrastructure.

c. Do the various announcements present any opportunities for DTE Electric to advance transportation electrification in addition to those that DTE Electric proposed in this case? If so, please explain those opportunities.

Answer: The Company views the elements presented in this case to be well aligned with these funding announcements. A couple of examples of this would be 1) the expansion of funding for electric transit buses paired with DTE Electric's proposal for Transit Batteries, which should further improve the economics for transit agencies to electrify their fleet, and 2) federal funding will be focused on highway corridor DCFC deployment, and DTE Electric's rebates and incentives will help support those installations.

However, additional guidance will be needed in order for DTE Electric to fully understand the opportunities available, including the State of Michigan's Transportation Electrification plan which is due 8/1/22 but can be submitted at any point before then. As soon as that plan is submitted, the Company will be able to confidently begin engaging with customers that would qualify for funding.

Attachment: *None*

DTE Electric Company
Plant Study
Production COSS by Unit/Grouping
(thousands of dollars)

Case No. U-20836
Exhibit No. (DJ9)
Schedule No. W1
Witness: D B Jester
Page: Page 1 of 5

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		- Total Electric	Belle River Unit 1	Belle River Unit 2	Greenwood	Monroe Unit 1	Monroe Unit 2	Monroe Unit 3	Monroe Unit 4	Range Road	River Rouge Unit 3
1	Rate Base	10,745,775	653,228	644,630	296,661	1,051,934	1,062,274	1,007,175	830,958	12,038	4,657
2	Revenue	3,208,413	176,963	179,136	102,877	272,953	266,951	267,085	222,220	1,360	5,103
3	Expenses:										
4a	Fuel	645,889	53,612	54,683	29,981	97,243	94,116	95,808	79,920	12	(0)
4b	Transmission Purchases	317,922									
4c	MERC	7,413	836	853		1,516	1,468	1,494	1,246		
5	Purchased Power	395,929									
6	O & M Expense	627,483	39,054	39,833	33,134	56,782	54,956	55,944	46,667	11	(0)
7	Depreciation	454,101	38,644	39,416	16,383	46,425	44,930	45,737	38,156	629	(0)
8	Other (Reg Assets, etc)										
9	Remove Reg Assets										
10	Accretion of Loss/ Gain on Sale										
11	Other Taxes	136,002	7,281	7,427	6,239	9,100	8,808	8,966	7,479	9	4,810
12	Income Taxes	89,299	5,428	5,357	2,465	8,742	8,828	8,370	6,905	100	39
13	Amortizations	-	-	-	-	-	-	-	-	-	-
14	Total Expenses	2,674,037	144,856	147,568	88,203	219,808	213,105	216,319	180,374	761	4,849
15	Net Oper Income	534,376	32,107	31,568	14,674	53,145	53,845	50,766	41,846	600	254
16	AFUDC & Other	42,770	3,428	3,499	1,464	4,079	3,941	4,023	3,358	55	(1)
17	Net Adjustments	(896)	(54)	(54)	(25)	(88)	(89)	(84)	(69)	(1)	(0)
18	Adj Net Oper Income	576,250	35,480	35,013	16,113	57,136	57,698	54,705	45,134	654	253
19	Rate of Return	5.36%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%
20	Return @ 5.556 %	597,035	36,293	35,816	16,483	58,445	59,020	55,959	46,168	669	259
21	Income Deficiency	20,785	813	802	369	1,309	1,322	1,253	1,034	15	6
22	Base Revenue Def / (Sufficiency)	18,047	1,097	1,083	498	1,767	1,784	1,692	1,396	20	8
23	Additional Rev Req	0	-	-	-	-	-	-	-	-	-
24	Total Revenue Def/ (Sufficiency)	18,047	1,097	1,083	498	1,767	1,784	1,692	1,396	20	8
25	Revenue Requirement	3,226,461	178,060	180,218	103,376	274,720	268,735	268,776	223,616	1,381	5,111
26	Misc Revenue	42,746	3,722	3,796	1,592	4,473	4,329	4,407	3,676	60	(0)
27	Rev Req Excl Misc Rev & Nuc Decomm	3,183,715	174,338	176,422	101,783	270,247	264,405	264,369	219,939	1,320	5,111

DTE Electric Company
Plant Study
Production COSS by Unit/Grouping
(thousands of dollars)

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		(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
		Sibley	St. Clair Unit 1	St. Clair Unit 2	St. Clair Unit 3	St. Clair Unit 6	St. Clair Unit 7	CC and HB	Trenton Unit 9
1	Rate Base	20,003	16,890	62,105	50,318	140,713	162,377	9,828	223,156
2	Revenue	2,348	1,062	5,078	4,217	11,957	13,573	871	18,226
3	Expenses:								
4a	Fuel	22	-	-	-	-	-	-	-
4b	Transmission Purchases								
4c	MERC								
5	Purchased Power		-	-	-	-	-	-	-
6	O & M Expense	20	-	-	-	-	-	-	-
7	Depreciation	1,135	-	-	-	-	-	-	-
8	Other (Reg Assets, etc)								
9	Remove Reg Assets								
10	Accretion of Loss/ Gain on Sale								
11	Other Taxes	16	-	1,174	1,054	3,112	3,365	254	4,199
12	Income Taxes	166	140	516	418	1,169	1,349	82	1,854
13	Amortizations	-	-	-	-	-	-	-	-
14	Total Expenses	1,360	140	1,690	1,472	4,281	4,715	335	6,053
15	Net Oper Income	988	921	3,388	2,745	7,676	8,858	536	12,173
16	AFUDC & Other	100	(3)	(9)	(8)	(21)	(25)	(1)	(34)
17	Net Adjustments	(2)	(1)	(5)	(4)	(12)	(14)	(1)	(19)
18	Adj Net Oper Income	1,086	917	3,373	2,733	7,643	8,820	534	12,121
19	Rate of Return	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%
20	Return @ 5.7338 %	1,111	938	3,451	2,796	7,818	9,022	546	12,399
21	Income Deficiency	25	21	77	63	175	202	12	278
22	Base Revenue Def / (Sufficiency)	34	28	104	85	236	273	17	375
20	Return @ 5.7338 %	-	-	-	-	-	-	-	-
24	Total Revenue Def/ (Sufficiency)	34	28	104	85	236	273	17	375
25	Revenue Requirement	2,381	1,090	5,182	4,301	12,194	13,845	888	18,601
26	Misc Revenue	109	-	-	-	-	-	-	-
27	Rev Req Excl Misc Rev & Nuc Dec	2,272	1,090	5,182	4,301	12,194	13,845	888	18,601

DTE Electric Company
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		(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)
		Fermi 2	Ludington	Belle River Peak	Blue Water	Colfax Station	Dean Peaking	Dearborn EC	Delray Peaking	Fermi Peaking	Greenwood Peak
1	Rate Base	2,064,993	505,393	50,538	1,088,513	986	151,679	72,421	26,752	6,595	27,536
2	Revenue	557,110	81,843	15,480	145,411	182	32,342	12,952	5,199	906	8,204
3	Expenses:										
4a	Fuel	38,776	496	8,187	38,057	41	17,106	5,978	1,295	10	2,967
4b	Transmission Purchases										
4c	MERC										
5	Purchased Power										
6	O & M Expense	269,997	11,898	965	10,900	19	1,390	588	523	117	780
7	Depreciation	93,281	23,265	3,249	28,784	64	4,656	1,979	1,761	393	2,628
8	Other (Reg Assets, etc)										
9	Remove Reg Assets										
10	Accretion of Loss/ Gain on Sale										
11	Other Taxes	37,829	15,633	218	2,027	2	110	47	109	9	353
12	Income Taxes	17,160	4,200	420	9,046	8	1,260	602	222	55	229
13	Amortizations	-	-	-	-	-	-	-	-	-	-
14	Total Expenses	457,044	55,493	13,038	88,814	134	24,522	9,194	3,910	584	6,957
15	Net Oper Income	100,066	26,350	2,442	56,597	48	7,821	3,759	1,289	322	1,247
16	AFUDC & Other	12,267	1,143	307	2,617	6	431	181	167	37	250
17	Net Adjustments	(172)	(42)	(4)	(91)	(0)	(13)	(6)	(2)	(1)	(2)
18	Adj Net Oper Income	112,161	27,451	2,745	59,123	54	8,239	3,934	1,453	358	1,496
19	Rate of Return	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%
20	Return @ 5.7338 %	114,731	28,080	2,808	60,478	55	8,427	4,024	1,486	366	1,530
21	Income Deficiency	2,570	629	63	1,355	1	189	90	33	8	34
22	Base Revenue Def / (Sufficiei	3,468	849	85	1,828	2	255	122	45	11	46
20	Return @ 5.7338 %	-	-	-	-	-	-	-	-	-	-
24	Total Revenue Def/ (Sufficien	3,468	849	85	1,828	2	255	122	45	11	46
25	Revenue Requirement	560,578	82,692	15,565	147,239	183	32,597	13,074	5,244	917	8,251
26	Misc Revenue	6,528	2,465	419	3,712	8	604	255	227	51	339
27	Rev Req Excl Misc Rev & Nu	554,050	80,226	15,146	143,527	175	31,993	12,819	5,016	866	7,912

DTE Electric Company
Plant Study
Production COSS by Unit/Grouping
(thousands of dollars)

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		(ac)	(ad)	(ae)	(af)	(ag)	(ah)	(ai)	(aj)
		Hancock St Peak	Monroe PP Peak	Northeast St Peak	Oliver St Peaking	Placid St Peaking	Putnam St Peak	Remer-BR Peak	Renaissance Pp
1	Rate Base	8,616	459	16,804	1,024	1,062	943	1,134	323,425
2	Revenue	1,103	108	2,650	164	202	184	257	66,240
3	Expenses:								
4a	Fuel	(7)	17	662	19	53	44	58	26,273
4b	Transmission Purchases								
4c	MERC								
5	Purchased Power								
6	O & M Expense	138	15	226	20	20	19	31	2,998
7	Depreciation	465	50	762	66	67	65	104	13,084
8	Other (Reg Assets, etc)								
9	Remove Reg Assets								
10	Accretion of Loss/ Gain on Sale								
11	Other Taxes	11	1	18	2	2	2	2	4,315
12	Income Taxes	72	4	140	9	9	8	9	2,688
13	Amortizations	-	-	-	-	-	-	-	-
14	Total Expenses	678	87	1,807	115	151	139	205	49,357
15	Net Oper Income	425	20	843	49	51	45	52	16,883
16	AFUDC & Other	44	5	71	6	6	6	10	711
17	Net Adjustments	(1)	(0)	(1)	(0)	(0)	(0)	(0)	(27)
18	Adj Net Oper Income	468	25	913	56	58	51	62	17,567
19	Rate of Return	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%	5.43%
20	Return @ 5.7338 %	479	25	934	57	59	52	63	17,969
21	Income Deficiency	11	1	21	1	1	1	1	402
22	Base Revenue Def / (Sufficiei	14	1	28	2	2	2	2	543
20	Return @ 5.7338 %	-	-	-	-	-	-	-	-
24	Total Revenue Def/ (Sufficien	14	1	28	2	2	2	2	543
25	Revenue Requirement	1,117	108	2,678	166	204	185	259	66,783
26	Misc Revenue	60	7	98	9	9	8	13	1,303
27	Rev Req Excl Misc Rev & Nu	1,057	102	2,580	158	195	177	245	65,480

DTE Electric Company
Plant Study
Production COSS by Unit/Grouping
(thousands of dollars)

Case No. U-20836
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		(ak)	(al)	(am)	(an)	(ao)	(pp)	(ap)	(aq)
		River Rouge Peak	Slocum St Peak	St Clair PP Peak	Superior St Peak	Wilmot Peaking	Purchased Power	MERC	Transmission
1	Rate Base	482	22,609	3,095	10,189	827	-	32,912	77,843
2	Revenue	124	2,250	456	1,350	199	395,929	7,358	325,641
3	Expenses:								
4a	Fuel	31	51	71	233	73		-	317,922
4b	Transmission Purchases								
4c	MERC								-
5	Purchased Power						395,929	-	
6	O & M Expense	15	189	46	116	18		-	54
7	Depreciation	51	635	155	390	61		4,102	2,528
8	Other (Reg Assets, etc)								
9	Remove Reg Assets								
10	Accretion of Loss/ Gain on Sale								
11	Other Taxes	1	15	4	9	1		1,200	788
12	Income Taxes	4	188	26	85	7		274	647
13	Amortizations	-	-	-	-	-		-	-
14	Total Expenses	103	1,078	302	832	160	395,929	5,575	321,939
15	Net Oper Income	21	1,172	154	518	39	-	1,783	3,702
16	AFUDC & Other	5	58	15	36	6		8	532
17	Net Adjustments	(0)	(2)	(0)	(1)	(0)		(3)	(6)
18	Adj Net Oper Income	26	1,228	168	553	45		1,788	4,228
19	Rate of Return	5.43%	5.43%	5.43%	5.43%	5.43%	N/A	5.43%	5.43%
20	Return @ 5.7338 %	27	1,256	172	566	46	N/A	1,829	4,325
21	Income Deficiency	1	28	4	13	1	N/A	41	97
22	Base Revenue Def / (Sufficie	1	38	5	17	1	N/A	55	131
20	Return @ 5.7338 %	-	-	-	-	-		-	-
24	Total Revenue Def/ (Sufficie	1	38	5	17	1	-	55	131
25	Revenue Requirement	125	2,288	461	1,368	201	395,929	7,413	325,772
26	Misc Revenue	7	82	20	50	8	-	7,413	295
27	Rev Req Excl Misc Rev & N	118	2,206	441	1,317	193	395,929	-	325,477

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-2.39
Respondent:	J. Robinson
	1 of 1

Question: Provide an Excel file that identifies each of DTE's 3239 primary distribution circuits and for each provides its primary distribution voltage, number of customers by major class (residential, commercial, and industrial), and provide an 8760-hour load profile for 2019 or an 8784-hour load profile for 2020.

Answer: The DTE Electric Company objects to providing the requested information for the reasons that the request is overly broad, seeks excessive detail, is unduly burdensome, is not reasonably calculated to lead to the discovery of admissible evidence in this proceeding. The Company does not have hourly data on all or even most of the 3239 circuits available, and it would be excessively burdensome to produce the voltage and number of customers by class in that the Company would have to perform a manual review of each of the 3239 circuits to determine the location of each customer, the class of the customer, and the voltage of each. This would require hundreds of man hours to produce and is not proportional to the unclear relevancy of the information to determining whether the Company's proposed rates are reasonable and prudent. In further answer and without waiving the objection, the Company would state as follows:

The information as requested is not available. Complete data to compile an 8760-hour load profile is not available on all 3239 primary distribution circuits at this time.

Attachment: N/A

Michigan Public Service Commission
DTE Electric Company
Capacity Charge Revenue Requirement by Customer Class
TME October 31, 2023
(thousands of dollars)

CAPACITY CHARGE
Cost of Service Study
75-0-25
PRODUCTION COSTS

Case No. U-20836
Exhibit: (DJ11)
Schedule: F1.5
Witness: D B Jester
Page: 1 0f 1

		(a) Total Electric with 2020 Reconciliation	(b) Total Electric without 2020 Reconciliation
	CAPACITY COSTS DETERMINATION		
1	Net Production Costs Rev. Req. (Exh A-16 Sch F1.1 Line 27)	$ 2,802,137	$ 2,802,137
2	Less Fuel (Exh A-16 Sch F1.1 Line 4)	(653,302)	(653,302)
3	Less MISO Energy in PP (Exh A-13 Sch C4 Lines 20-21)	(36,539)	(36,539)
4	Less Other Energy in PP (WPA16PF1 Sch 11.5 Line 14)	(234,384)	(234,384)
5	Less Variable O&M (Exh A-16 Sch F1.5 Page 5 Line 8)	(31,768)	(31,768)
6	Subtotal	$ 1,846,144	$ 1,846,144
7a	Proj 2022 Energy Sales Rev Net of Fuel (Per A-26, Sch P3, Line 26)	(895,162)	(895,162)
7b	Proj 2022 Energy Sales Rev Net of Fuel (Per A-26, Sch P3, Line 27)	245,295	-
7	Proj 2022 Energy Sales Rev Net of Fuel inc 2022 reconciliation (Per A-26, Sch	(649,867)	(895,162)
8	Capacity Revenue Requirement (Line 6 + Line 7)	$ 1,196,277	$ 950,981
	Allocator		
9	Sch 200B 4 CP Excl R10	100.0000	100.0000
	Revenue Requirement		
10	Capacity Revenue Requirement (Line 8 * Line 9/100)	$ 1,196,277	$ 950,981
11	Non-Capacity Revenue Requirement (Line 12 less Line 10)	1,987,439	2,232,734
12	Total Production Revenue Requirement (Exh A-16 Sch F1.1 L 27)	$ 3,183,715	$ 3,183,715

MPSC Case No.:	U-20836
Requestor:	MNSC
Question No.:	MNSCDE-2.32
Respondent:	S. Burgdorf
	1 of 1

Question: Please explain whether it is DTE's practice to report demand to MISO, for purposes of MISO cost allocation and resource adequacy, as only inflow to customers with behind-the- meter resources or as net of outflow for such customers. If the answer differs between customers enrolled in net metering, those in a distributed generation tariff, and those whose outflow is sold to DTE pursuant to PURPA, please answer for each.

Answer: DTE Bundled Load and DTE MISO load are both used for cost allocation depending on the settlement charge type. DTE Bundled Load is used for resource adequacy requirements and settlement purposes. Customers generation and load that are enrolled in net metering or the distributed generation tariff would impact both values, however, the generation and load values are not separated from the totals of each component. Generation sold to the Company from PURPA resources is included in the Generation component for both load formulas and is also in the Behind the Meter Generation (BTMG) component.

DTE Electric calculates load submitted to MISO with the following two formulas:

1) **DTE Bundled Load = Generation + Net Interchange – Choice Customer Load – Municipality Load**
2) **DTE MISO Load = Generation + Net Interchange – Choice Customer Load – Municipality Load – BTMG – Transmission Losses**

Attachment: N/A

RAP®

REGULATORY ASSISTANCE PROJECT

NOVEMBER 2020

Demand Charges: What Are They Good For?

An Examination of Cost Causation

Mark LeBel and Frederick Weston, with contributions from Ronny Sandoval

Contents

Acknowledgments

Editorial assistance was provided by Ruth Hare and Donna Brutkoski.

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- Karl R. Rábago, Rábago Energy LLC
- Jim Lazar, Carl Linvill and Ann McCabe, RAP

We would also like to thank GridLab for providing funding for Ronny Sandoval's participation in this project. When the report was drafted, Mr. Sandoval was working as an independent consultant. At the time of publication, he is employed at Vote Solar.

The analysis in this paper rests on the shoulders of earlier RAP publications, in particular:

Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

Linvill, C., Lazar, J., Dupuy, M., Shipley, J., & Brutkoski, D. (2017). *Smart non-residential rate design.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/

Weston, F. (2000). *Charging for distribution utility services: Issues in rate design.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/charging-for-distribution-utility-services-issues-in-rate-design/

That said, responsibility for the information and views set out herein lies entirely with the authors.

Executive Summary

Demand charges, rates that are applied to an individual customer's maximum short-term usage (typically 15, 30 or 60 minutes) in a billing period, have existed since nearly the beginning of the electric industry. While utilities often favor demand charges, economists have continually questioned whether they are an efficient form of pricing. With the widespread adoption of advanced metering, this is an opportune time to reconsider demand charges, even for industrial customers, and replace them with more efficient time-varying energy (kilowatt-hour) rates.

Traditional monthly demand charges have always provided a perverse incentive that does not reflect cost causation for shared system costs. Individual customer noncoincident peaks (NCPs) do not reflect the coincident peaks that drive *shared* generation and delivery capacity costs. The price signal that demand charges send — to lower individual customer NCP and to level a customer's load over time — is substantially different than a price signal to reduce usage at the time of coincident peaks. As a result, demand charges penalize customers for usage at times that do not impose particularly high costs and encourage them to waste effort and money shifting loads off their own maximum hour (and sometimes onto high-load system hours).

The historic exception to this rule is a customer that has a nearly 100% coincidence factor with the relevant peaks. The prototypical example of this in the mid-20th century was an industrial customer with very high load factors. Demand charges could be reasonable in the past only as applied to this specific category of customers. But, in today's electric system, even this justification for demand charges falls away. High penetrations of nondispatchable but variable renewable generation means that a 100% load factor is unlikely to be, from a system perspective, the most desirable load shape. Rather, flexible load — load that can respond to swift changes in the availability of supply, perhaps in the middle of the day for solar and late at night with wind — becomes cheaper to serve than unvarying loads in systems marked by high penetrations of variable supply.

Historically, demand charges have frequently been sized to recover most or all shared system capacity costs. Again, this may have been reasonable enough in the mid-20th century for certain customers, but it does not reflect the economics and engineering of a modern electric system. The choices that system planners make are trade-offs between different types of costs. Much "capacity" investment today aims to reduce energy costs and is not incurred to meet peak reliability needs. This means that a significant portion of investment in generation, transmission and distribution plant (and the associated operation and maintenance expense) cannot be reasonably described as demand-related or driven by peak reliability needs. Any pricing structures that reflect the marginal costs of peak system capacity should be sized properly to reflect these distinctions. That includes

demand charges, if appropriate, as well as time-varying energy pricing.

It is fair to ask whether a properly sized "peak window" demand charge solves these issues. Although such a charge is superior to traditional demand charges for the pricing of shared capacity costs, peak window demand charges nonetheless retain many of the shortcomings of their traditional counterparts. Customers who have high usage at many times throughout the peak period should be charged more for capacity than customers who have a single high usage interval in that same window. Time-varying energy pricing provides superior incentives to optimize usage at all relevant times. Simple time-of-use rates are fairer and more efficient than peak window demand charges and can be made even more so by overlaying them with pricing that is responsive to critical peak conditions.

A few analysts and economists have identified several narrower applications where pricing structures akin to demand charges could be appropriate and reasonably efficient: (1) site infrastructure for individual customers, (2) risks related to customer variability at peak times and (3) timer peaks. While more research into these applications might be merited, demand-based pricing would only be a second-best approximation of a more efficient but potentially more administratively complex time- and location-based pricing system.

1. Introduction

Demand charges have existed almost since the beginning of the electric industry in the 1880s. They were originally called Hopkinson rates after John Hopkinson, a British engineer who described the concept in 1892. Hopkinson believed that costs of "plant and conductors"[1] — namely capacity costs — for an electric utility should be charged to customers based on the "greatest rate of supply the consumer will ever take."[2] Shortly thereafter, a meter was developed that could capture the highest kW power draw from the customer, defined over a period of an hour or half-hour, during an entire billing period (now typically a month). These rates became prevalent for industrial customers in the early 1900s.[3]

It did not take long, however, before economists called into question their putative cost-causation rationale. In 1941, future Nobel Prize winner in economics W. Arthur Lewis argued that the cost-causation case for demand charges was often based on "a simple confusion. ... The maximum rate at which the individual consumer takes is irrelevant; what matters is how much he is taking at the time of the station's peak."[4] In 1970, prior to becoming chairman of the New York Public Service Commission, Cornell University professor Alfred E. Kahn wrote that demand charges are "basically illogical."[5] More recently, University of California professor and California Independent System Operator board member Severin Borenstein opined that "it is unclear why demand charges still exist."[6]

Electric utilities and some consultants still make broad arguments for demand charges that are, at their core, the same as those made more than a century ago. In 2016, the Edison Electric Institute (EEI) asserted that "demand charges provide accurate price signals" and "better collect capacity costs [than other kinds of prices]."[7] EEI made this

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[1] Hopkinson, J. (1901). *Original papers: Vol. 1, Technical papers*, p. 257. Cambridge University Press.

[2] Hopkinson, 1901, p. 261.

[3] There was a debate within the electric utility industry about rate design in the 1890s. A time-of-use meter was invented nearly simultaneously with the demand meter, and some industry participants argued that time-of-use rates would be superior. See Hausman, W. J., & Neufeld, J. L. (1984). Time-of-day pricing in the U.S. electric power industry at the turn of the century. *The RAND Journal of Economics, 15*(1). This time-of-use meter disappeared from discussion relatively quickly, however, as an industry consensus formed around demand charges. Neufeld argues that demand charges were a part of utility strategy to discourage industrial customers from relying on distributed generation, known as "isolated plants" at the time. Neufeld, J. (1987, September). Price discrimination and the adoption of the electricity demand charge. *Journal of Economic History, 47*(3), 693-709. In addition, Samuel Insull, president of Chicago Edison (later Commonwealth Edison) and a major player in the industry, happened to own a part of the patent for the demand charge meter. See Yakubovich, V., Granovetter, M., & McGuire, P. (2005). Electric charges: The social construction of rate systems. *Theory and Society, 34,* 597-612.

[4] Lewis, W. A. (1941). The two-part tariff. *Economica, 8*(41), 252.

[5] Kahn, A. E. (1970). *The economics of regulation: Principles and institutions: Vol. 1, Economic principles*, p. 96. John Wiley & Sons.

[6] Borenstein, S. (2016). The economics of fixed price recovery. *The Electricity Journal, 29*(7), 10.

[7] Edison Electric Institute. (2016, February). *Primer on rate design for residential distributed generation,* p. 6. https://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/2016%20Feb%20NARUC%20Primer%20on%20Rate%20Design.pdf

argument simultaneously for two different types of demand charges: (1) the traditional monthly noncoincident peak (NCP)[8] demand charge, based on an individual customer's NCP across an entire billing period, and (2) a peak window demand charge,[9] based on an individual customer NCP within a defined multihour interval, similar to the on-peak period for a time-of-use (TOU) rate.[10] In addition, there has been a push by EEI and many utilities to expand the application of demand charges beyond just the industrial and large commercial customer classes to small business and even residential customer classes.

Demand charges as we've known them in the United States should largely become a relic of the past. Current forms of demand charges, based on 15-minute, 30-minute or 60-minute individual customer peaks and often intended to recover the lion's share of capacity costs, are neither cost reflective nor efficient in general.[11] For much of the 20th century, traditional demand charges may have been a second-best alternative that worked reasonably well for high-load-factor industrial customers. Developments of the past several decades have, however, made even this application of demand charges archaic. Such charges do not reflect the cost drivers of the modern electric system, and typical sizing of these charges are larger than justified by proper economic analysis of the electric system. Peak window demand charges, while an improvement over their traditional counterpart, do not solve many of the core deficiencies of demand charges as an efficient pricing mechanism. Time-varying rates, including TOU rates and critical peak pricing, are more efficient than peak window demand charges.

If there is a role for demand charges in today's electric system, it is much narrower than the one it performs for industrial customers in many jurisdictions. Modern versions of

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[8] A customer's noncoincident peak is its highest demand, in kilowatts, measured at the meter during the period in question. This customer demand can be measured based on different intervals, typically 15, 30 or 60 minutes. "Noncoincident" means that this demand does not necessarily occur at the time of a system peak.

[9] There is no standardized terminology for this type of demand charge where determination of the maximum demand for the billing period considers only a limited number of peak hours, similar to the peak period for a time-of-use rate. We find the "peak window demand charge" description more apt than the other alternatives.

[10] Less commonly, daily-as-used demand charges are part of the discussion, which we raise later in this paper. As the name implies, it is a demand charge for a customer's individual NCP in a given 24-hour period, sometimes limited to a peak window within that day and sometimes excluding weekends and holidays. This means that the ratchet feature of a daily-as-used demand charge is reset every day and not every billing period, as with other demand charges. In this paper, we do not focus on contract (ex ante) demand charges, although they share many features with these other alternatives.

[11] There are other issues at play in the debate around demand charges, particularly whether residential and small business customers can understand and manage these types of rates and the related potential for inequitable bill impacts. See Chernick, P., Colgan, J., Gilliam, R., Jester, D., & LeBel, M. (2016). *Charge without a cause? Assessing electric utility demand charges on small consumers.* (Electricity rate design review paper No. 1). https://votesolar.org/files/6414/6888/3283/Charge-Without-CauseFinal_71816.pdf; and Lazar J. (2015). Use great caution in design of residential demand charges. *Natural Gas & Electricity*. https://www.raponline.org/wp-content/uploads/2016/05/lazar-demandcharges-ngejournal-2015-dec.pdf. The question of understandability of demand charges by residential and small business customers is a longstanding one. D. J. Bolton notes that a 1948 report by a government commission in Great Britain rejected demand charges for residential customers on two bases: (1) understanding of the rate and (2) the potential reaction to an overload encouraging higher usage levels going forward. Bolton, D. J. (1951). *Electrical engineering economics: Vol. 2, Costs and tariffs in electricity supply*, p. 255. (2nd ed. rev.). Chapman & Hall. We do not delve into these issues at length in this paper.

these charges need to be more rigorously fashioned to achieve economic efficiency and advance the public good than they have been historically. We examine three more nuanced cases where demand charges have been identified as a potentially efficient pricing mechanism: (1) site infrastructure for individual customers, (2) risks related to customer variability at peak times and (3) timer peaks. In these situations, pricing structures with some similarities to demand charges may be appropriate. In each of these cases, demand-based pricing would only be a second-best approximation of a more efficient time- and location-based pricing system.

Unless we reexamine fundamental ratemaking practices critically in light of the modern electric system and new technologies, we will miss major opportunities to optimize system costs, ensure reliability and improve societal outcomes. While utilities and some consultants have been pushing for new applications for demand charges, regulators and utilities should be moving in the opposite direction by replacing demand charges for industrial customers with more accurate pricing mechanisms.

2. Historic Cost-Causation Argument for Demand Charges

A frequently used but inaccurate cost-causation argument for demand charges begins with the observation that several of the most important cost categories can be denoted in kilowatts (kW) or megawatts (MW).

- Generation capacity is denominated in kW or MW, reflecting the maximum instantaneous power output of a given unit.
- Transformers are rated in kilovolt-ampere (kVA) or megavolt-ampere (MVA), a unit of apparent power[12] closely related to kW or MW.
- Conductors are rated in amps for the level of current that they can handle. For a given voltage, this leads to a maximum kW or MW power flow for that conductor (power equals current times voltage).[13]

From these engineering descriptions, which are accurate but potentially misleading, some analysts conclude that, because generation and delivery capacity can be measured in units of power (kW or MW), their costs are demand-related. Making the leap to retail rate design then becomes easy: Capacity costs are rated in kW, so prices should be reflected

[12] Apparent power is the combination of active and reactive power in an alternating current circuit that needs to be supplied to serve load. This includes the power components that are needed to energize the circuit but don't transfer useful power to the load.

[13] For three-phase power, power is current times voltage times the square root of 3.

in kW.[14] This is the essence of the argument made by EEI, but it rests on several fallacies.

Some earlier writers, including W. Arthur Lewis, D. J. Bolton and James Bonbright, are open to demand charges to a certain extent but are quite candid about their limitations and significant downsides. Important factors in this more nuanced determination include:

- The diversity and coincidence factors[15] of any group of customers who might face a demand charge.
- The relative metering costs for flat kilowatt-hour (kWh) rates, demand rates and time-varying rates.
- The ability (or lack thereof) for customers to economically shift certain types of load.
- The broad similarity of capacity and fuel costs for many generation alternatives (typically thermal steam units) prior to 1960.

Lewis acknowledged the metering problem in his 1941 article, "The Two-Part Tariff." He stated that "the two-part tariff [a demand charge and an energy charge] is superior to having a single undifferentiated price which discourages off-peak consumption, *but inferior to charging different prices at different times*, though it may sometimes be more convenient than the latter if the measurement and timing of consumption are costly."[16] In the early and mid-20th century, only simple kWh metering was economic for small customers (that is, the system benefit from the response to time-differentiated pricing did not exceed the cost of the metering necessary to support it), while more sophisticated metering could be justified for industrial customers.

In 1951 Bolton noted, with some approval, that demand charges were much more common for industrial customers than residential.[17] He observed that residential customers' peaks are more random, that is to say more diverse (spread out in time) and less likely to be correlated with system peaks: "A metered demand system for such a [residential] consumer would mean making a high charge for payment at times when it was most unlikely to matter."[18] He opined that the load of many large industrial customers is not

[14] It is worth noting that these "kW" demand measurements are actually measured in units of kilowatt-hours per hour and simplified to be presented as measures of kW demand.

[15] Diversity of demand for a utility reflects the temporal differences in usage among customers. Peak coincident demand at any level of the system is less than the sum of customers' individual peaks because of these temporal differences. The calculated "diversity factor" provides a quantitative measure of these differences; conversely, a "coincidence factor" measures the extent to which these individual peaks do line up. These concepts are defined and discussed further in Section 3.1.

[16] Lewis, 1941, pp. 255-256 (emphasis added). Even in 1941, Lewis thought that it was no longer the case that demand metering would be cheaper than time-based metering, with one alternative being simple timers and another being "ripple control," where a utility sends a high frequency signal to flip an equipment switch.

[17] Bolton, 1951, p. 255. Bolton's proposed ideal "scientific tariff" features a TOU rate and no demand charges, where the on-peak price recovers demand-related costs. See Bolton, 1951, pp. 249-250.

[18] Bolton, 1951, p. 255.

particularly susceptible to shaping, because it is "motive power" (i.e., motors to run large equipment), and the electricity costs represent a small fraction of overall costs for these firms.[19] This type of industrial customer has strong incentives, given a set amount of productive capacity, to have the highest operating factor possible and thus a high load factor.[20] This industrial load pattern implies a significant likelihood that an individual customer's peak in a given month or year is closely linked to the customer's demand at the time of system peak.

Bonbright, writing originally in 1961, stated that traditional demand charges provide some benefits from "a tendency of existing customers to spread their loads over a longer period in order to minimize their demand charges, instead of bunching them during short period likely to coincide with the heavy loads of other customers."[21] Bonbright then went on to observe that electric rate design in those days "[was] far from ideal, and practical rate makers will do well to consider seriously its alleged infirmities viewed from the standpoint of its critics among the academic economists." He noted in particular that there was little sense in "the imposition of demand charges which penalize consumers for high individual demands even though these demands come at hours or seasons that fall well off the peak loads imposed on the system as a whole or even on any major part thereof."[22]

Up until 1960, most generation options, with the exception of hydroelectric power, had very similar cost characteristics. Steam generation was the predominant capacity type, and there were few differences in cost among coal, oil and natural gas units. Even fuel prices were broadly similar. In such a system, there is a better case that all capacity is similarly situated to serve peak reliability needs and thus can be considered demand-related. As discussed later, this issue goes to the sizing of any demand charges if they can be shown to be a reasonable solution (in limited circumstances at best).

This combination of factors — (1) an industrial customer base with a relatively small number of customers, most of whom had high load factors, high peak-coincidence factors and high levels of consumption and (2) a large number of residential customers with lower coincidence factors and relatively low consumption per customer — provided a rough rationale for the rate designs that prevailed throughout most of the United States in the 20th century and are now lingering into the 21st. In pricing, this typically manifested itself in significant demand charges for large industrial classes to recover nearly all capacity costs and in fully volumetric energy rates for residential and small business customers.

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[19] Bolton, 1951, p. 238.

[20] Load factor is the ratio of an end user's actual energy usage in a period to its maximum potential usage in that period. It is calculated as follows: kWh/(peak demand x total hours), within the specified period.

[21] Bonbright, J. (1961). *Principles of public utility rates*, p. 311. Columbia University Press. https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/

[22] Bonbright, 1961, p. 316.

In this historical context, this could be relatively fair and efficient for a narrow slice of customers that meet the relevant description. To the extent that other customers that could share capacity (e.g., churches and schools; offices and movie theaters) were faced with demand charges, these customers were treated unfairly and often paid significantly more costs than they caused.

3. Why Demand Charges Are Inefficient

Some of these arguments for demand charges held sway in the past, even though the better case for time-varying energy charges was well understood. Today, the features of the modern electric system undermine even the more nuanced historic case for demand charges altogether. This is true for large industrial customers as well as for residential and small business customers.

The original advocates of demand charges often focused on what they thought was a fair and efficient division of historic accounting costs. Modern economists, even those who still advocate for demand charges, recognize that this older perspective is in error and argue (correctly) that rate structures should be designed to efficiently optimize *future* costs.[23] This perspective leads one to the conclusion that rates should be reflective of forward-looking marginal costs. In utility regulation, this concept is translated into different operative regulatory language in different jurisdictions, calling variously for rates that discourage wasteful usage, reflect actual costs or ensure the causer pays those costs. But in each case, the underlying microeconomic principle is the same: Rate design should ensure that the actions customers take to minimize their own bills are consistent with the actions they would take to minimize system costs. The nitty-gritty of designing rates in this framework is how to fairly and efficiently reflect marginal costs in prices. The best way to conceptualize this is to examine how the customer responds to a given rate design — both its form and its magnitude. An efficient rate design will lead to customer behavior that optimizes system costs.

The marginal consumption incentives for customers in any system of time-varying rates are fairly straightforward: (1) discourage usage in periods of relatively high rates and (2) encourage usage in periods of relatively low rates. Prices that achieve these outcomes are charged in a way that is both (1) consistent (all kWh at a given time or system condition are treated the same) and (2) symmetric: If an increase in consumption causes a bill to rise by $10, then the same sized decrease causes a bill to decline by $10.

The incentives presented by a typical demand charge structure are somewhat more

[23] See, for example, Boiteux, M. (1960). Peak-load pricing. *The Journal of Business, 33*(2), 157-179. (H. W. Izzzard, Trans.); Kahn, 1970; and Crew, M. A., & Kleindorfer, P. R. (1979). *Public utility economics.* St. Martin's Press.

complex.[24] If a customer is perfectly flexible (indifferent as to when they take electricity from the grid) and has perfect foresight, a demand charge would clearly incentivize a 100% load factor within the relevant time frame (e.g., each month). Of course, such customers do not exist in the real world,[25] although there are some customers that come close to having 100% load factors because of the nature of their operations: 24-hour supermarkets, data centers and certain types of factories.

Because customers do not have perfect foresight and infinite flexibility, it is only possible to talk about the incentives created by a demand charge at a certain level of generality. The most obvious features of a demand charge are that it directly (1) discourages higher individual customer NCP demand and (2) encourages levelization of load within the relevant time period. The related key feature of all types of demand charges is that they act as a ratchet, even if the ratchet is not applied across multiple billing periods.[26] Once a certain level of demand has been reached, customers then face a *lower* marginal cost for the remainder of the period to which the demand charge applies, as long as they have a power draw between zero and their previous individual demand peaks.

When the demand charge impacts a particular consumption decision, it can be quite punitive — imagine paying $5 to $10 to make toast for a family, which is exactly what can happen with a poorly designed residential demand charge.[27] This shows up as a high marginal cost for a subset of hours and consumption decisions. But otherwise, if a particular consumption decision does not pose a substantial risk of setting the demand charge, then consumption becomes cheaper — defined solely by the other charges without any demand charge implications. This means that optimal customer decision-making under a demand charge is quite complex and depends on the level of foresight and the value of consumption across all of the relevant time periods. Of course, most customer decision-making will not necessarily be optimal but rather based on rules of thumb, particularly for residential and smaller commercial customers.

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[24] Sandford Berg and Andreas Savvides did some theoretical work that incorporated the granular incentives of a demand charge into a traditional economic model of consumption. See Berg, S. V., & Savvides, A. (1983, October). The theory of maximum kW demand charges for electricity. *Energy Economics (5)*4, 258-66. However, this was a two-period model with numerous simplifying assumptions. Such a simplified theoretical model does illuminate certain features of a demand charge, but the authors note numerous areas for further work. To our knowledge, this line of theoretical research has not been pursued.

[25] This is true in particular because customer “utility” from electricity is not solely about the amount of consumption. Customers also enjoy significant convenience benefits for certain usage timing, again assuming that on-site storage and energy management are not cheap and convenient enough to smooth these features out.

[26] Some rates that do not meet this criterion are occasionally described as demand charges, such as annual system coincident peak capacity charges. These types of charges may, however, be better thought of as a type of time-varying rate or perhaps in a third category of their own.

[27] A toaster is approximately 1 kW demand; see Home Energy Saver & Score: Engineering Documentation. (n.d.). *Default energy consumption of MELs*. http://hes-documentation.lbl.gov/calculation-methodology/calculation-of-energy-consumption/major-appliances/miscellaneous-equipment-energy-consumption/default-energy-consumption-of-mels. If a customer uses it for 15 minutes straight at the time of the customer’s individual peak, the monthly demand billing determinant increases by 1 kW with a corresponding bill increase.

As the analysis in the subsections that follow shows, demand charges — whether of the traditional monthly variety or the peak window variety — are inefficient and inequitable for the pricing of shared system costs, as is the continued reliance on them. There are three interrelated reasons for this:

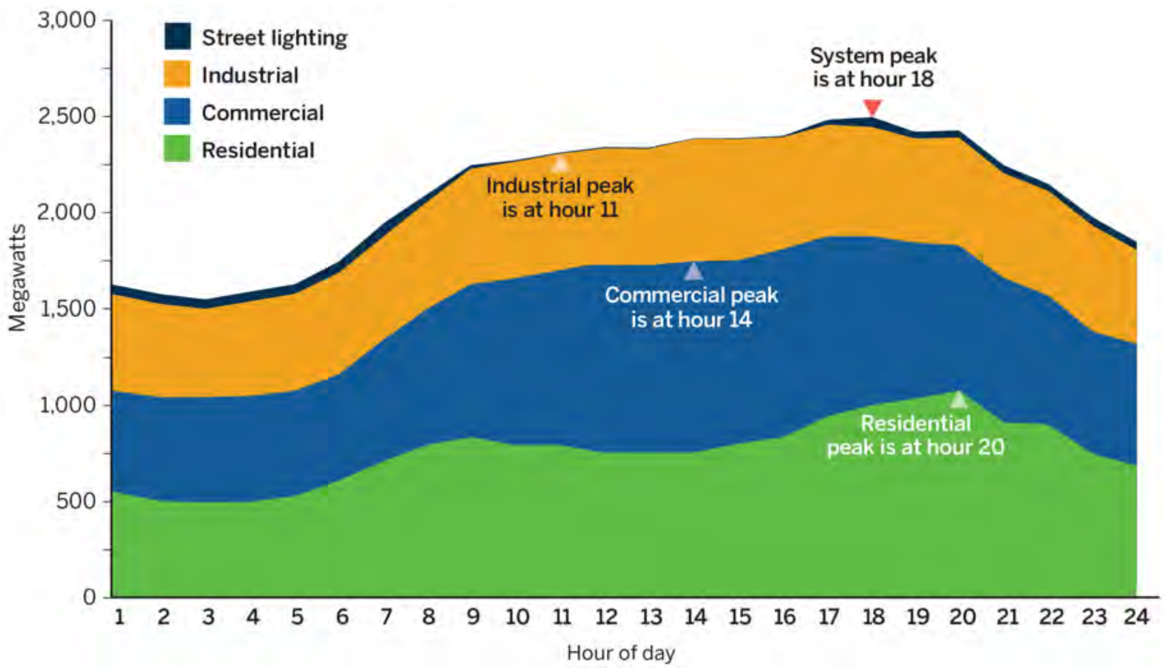
1. Traditional monthly demand charges provide an inaccurate price signal that is unrelated to high-cost periods for nearly all customers and which leads to inefficient customer efforts and investments in response to its incentives. The changes in the electric system due to dramatic increase in wind and solar generation mean that, from a system perspective, very high industrial load factors are not necessarily optimal.
2. Even in cases where a traditional demand charge could be justified, the sizing of demand charges to recover nearly all generation and delivery capacity costs reflects an outdated perspective of the engineering and economics of the electric system. Modern cost allocation and rate design must reflect the trade-offs between different types of expenses and investments. Much capacity investment is designed to reduce energy costs and line losses and should be charged on that basis.
3. Although a reasonably sized peak window demand charge is superior to a traditional monthly demand charge, time-of-use and other kinds of time-varying rates remain more efficient and equitable. These time-varying rate options are enabled by the dramatic decrease in the cost of sophisticated metering over the past two decades.

3.1 Individual Peaks Are Not the Same as System Peaks

Virtually all of the electric system consists of capacity that is shared among customers. With the exception of facilities that serve one or a very few customers, each component of the system is sized to meet an expected peak coincident demand of the customers it serves. The costs incurred to meet peak coincident demand, both short-run variable costs and capacity investment, are a significant portion of overall system costs. As a matter of economic efficiency, it is crucial that prices reflect the marginal costs of meeting the coincident system peak. Peak coincident demand is not simply the sum of the customers' individual peak demands but is rather something less, often significantly so. This phenomenon is known as *diversity* of demand and reflects the temporal differences of usage across the relevant customer base.

Customer loads are diversified at every level of the utility system. At the system level, the peak is determined by that combination of customer class loads that produces the highest instantaneous demand. That system peak might, or might not, coincide with the peak demand of any one customer class, and that system is likely interconnected to other systems with slightly different loads, through a shared transmission network. Figure 1 shows illustrative customer class loads on a system peak day. Each of the customer classes has a highest load hour at a different time: hour 11 for industrial, hour 14 for commercial and hour 20 for residential. The load for the lighting class is roughly the same across many different hours when the sun is down. The overall peak is at hour 18, which is different than any of the class peaks.

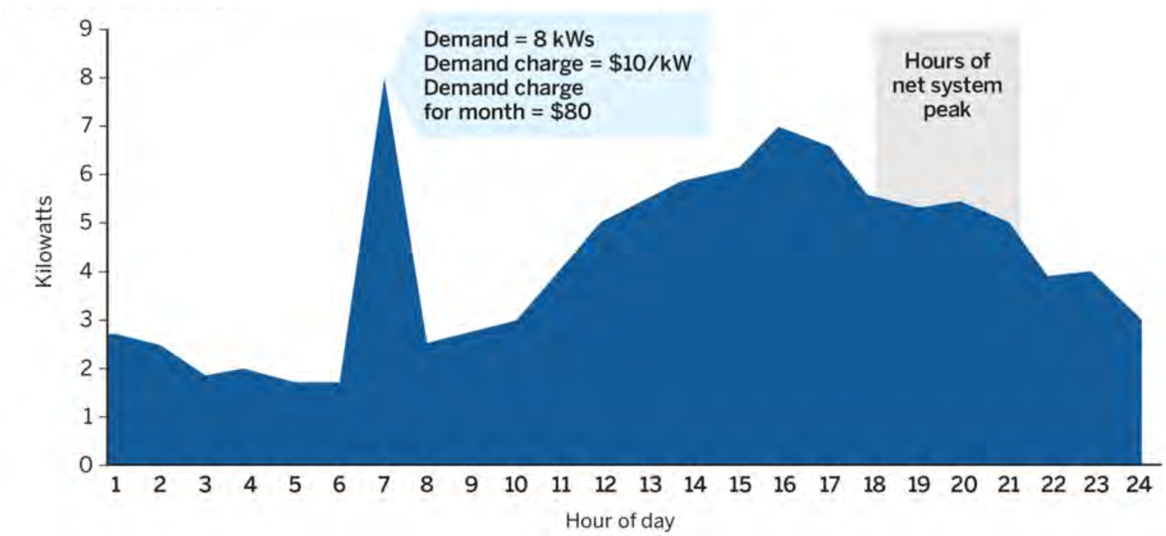
Figure 1. Diversity at the customer class level



Diversity can be quantified as the ratio of the sum of the subgroup peaks to the relevant coincident peak — the diversity factor. In this illustrative example, the diversity factor of the customer classes is 1.1. Diversity factors cannot go below 1 because in the extreme case where all subgroups peak at the same time, the sum of the subgroups equals the overall coincident peak. As long as customers peak at different times, diversity factors are higher as you consider smaller subgroups. Load diversity across individual customers is even greater than across customer classes.

Traditional monthly demand charges impose a rate on each customer that is independent of the system peak, as illustrated in Figure 2 on the next page. These demand charges provide little, if any, incentive to minimize a customer's contribution to system peak, unless a strong correlation exists between the customer's peak and the system's, a circumstance known as a high coincidence factor. In this illustrative example, a residential customer has an electric water heater that runs for nearly a full hour in the morning and a substantial cooling load in the afternoon.

Figure 2. Illustrative monthly noncoincident peak demand charge for an individual residential customer



Demand charges encourage customers to flatten their own load curves relative to their individual maximum usage but do not necessarily encourage them to consume energy in ways that optimize system costs. If we assume that Figure 2 shows customer usage before a traditional monthly demand charge is imposed, we could expect significant changes in usage after application of this charge. It would be reasonable to expect this customer to attempt to reduce the 8 kW demand reached at 7 a.m. In the case of an electric water heater, the individuals living in the house could change their behavior or adjust the settings on the water heater. If the customer could reduce that morning peak, then there would be some incentive to reduce the afternoon peak caused predominantly by cooling load. In this case, the customer would benefit by moving some portion of that load away from hour 16 to other hours, including possibly during the system peak from hours 18 to 21. Furthermore, this customer could increase overall kWh consumption since the marginal cost would be lower at times (often including the system peak) when there is little risk of triggering a higher demand charge.

More generally, a flat individual customer load shape may not, in fact, be what is best for the system and is in fact worse than a low load factor with predominantly off-peak usage. The clearest illustration of this is street lighting load, which, for most systems, falls entirely outside the system peak hours and has a roughly 50% load factor. If we designed and sized a demand charge for street lighting on the same basis as a typical demand charge for industrial customers, it would force this low-cost off-peak load to pay as much for system capacity as an industrial customer using the same amount of power during the peak periods. This is virtually never done, however, and street lighting is treated as a separate rate class without any demand charges.

D. J. Bolton summarized the basic problem facing utilities and regulators in the middle of the 20th century:

> The aim should always be the improvement of the *system* load factor, and the only justification for an elaborate tariff is that it shall contribute directly to this end. … If these costs are passed on to the consumer as they stand, in the form of a two-part [maximum demand] tariff, the fixed charge will be levied on the consumer's individual [maximum demand] instead of his effective demand on the system. The consequence will be that low-load-factor consumers will be overcharged (since they are given insufficient credit for their greater diversity) whilst the high-load-factor consumers are under-charged.
>
> The weakness of such a tariff when applied to the small individual consumer is that it treats load factor as a variable and diversity factor as a constant. … But, in practice, diversity factors vary from consumer to consumer almost as much as load factors, and moreover, in the opposite direction.[28]

In other words, diverse customers can efficiently *share* capacity, and rate design should recognize this fact. As Bolton mentioned, it is often the case that small users have *lower* load factors but more diversity and thus less impact on peak. This is still true today because many small residential users have lower levels of heating and cooling usage (smaller residences) and often have similar appliances (microwaves, toasters, dishwashers and dryers) that are used more sporadically than larger residential customers. This means that the load factor for each individual appliance is lower, but the power characteristics are similar for each usage of an appliance.

As described in Section 2, demand charges may present a rough price signal to control peak system demand for customers with a high system-peak coincidence factor. In that case, controlling a customer's individual peak does systematically reduce the overall coincident peak. One case where this could be true historically is large industrial customer classes, where individual customer usage is driven by large equipment that is constantly used throughout every working day of the year. Even for this type of customer, however, there remains the question of whether load can be shifted from peak hours to off-peak hours. A critical peak energy price would produce a superior price signal, to actively reduce usage at critical peak hours, rather than maintain steady usage at those hours if such a shift is possible. Indeed, industrial customers in Texas, faced with significant, narrowly focused transmission charges based on four coincident peak hours, use specialized consultants to help them identify, in advance, the hours to which those

[28] Bolton, 1951, p. 107-108 (emphasis in original). Bolton was writing at a time when, in operations, customer demand was taken largely as a given and much of the resource mix was dispatchable thermal generation. In those circumstances, improvement of system load factor would, all else again being equal including overall kWh consumption, lead to a reduction in total system costs.

charges will be applied and reduce usage sharply in those hours.[29]

For a diverse customer class, however, the share of customers who face this demand charge price signal at system peak times is random and inconsistent. In almost any hour, whether near system peak or the lowest-load hours of the year, some customers will face the demand charge price signal. Also, a substantial number and, at times, a majority of customers (e.g., those customers who have already hit their peaks in the billing period) face a lower marginal cost at system peak times. While this is very blunt and inaccurate, it could be a sharper price signal than a traditional flat kWh rate in some circumstances, although a customer's likelihood of facing those circumstances would vary randomly. In contrast, a well-designed TOU rate provides the broadly correct incentive for all marginal consumption choices by all customers, sending a consistent price signal for on-peak and off-peak periods; a critical peak pricing rate can be even more precise, focusing on specific hours when the electric system is under stress.[30]

The undesirable effects of demand charges are made worse by ratchets across billing periods — the mechanism by which a maximum demand in one period becomes the basis for minimum billed demand in subsequent periods. For example, billing demand may be the greater of this month's noncoincident maximum load and 80% of maximum in the previous 12 months. Once a maximum demand is hit, the customer has little incentive to reduce demand in the following periods. Unless individual customer peak is closely linked to system peak, there remains little incentive to minimize usage at a time of system peak.

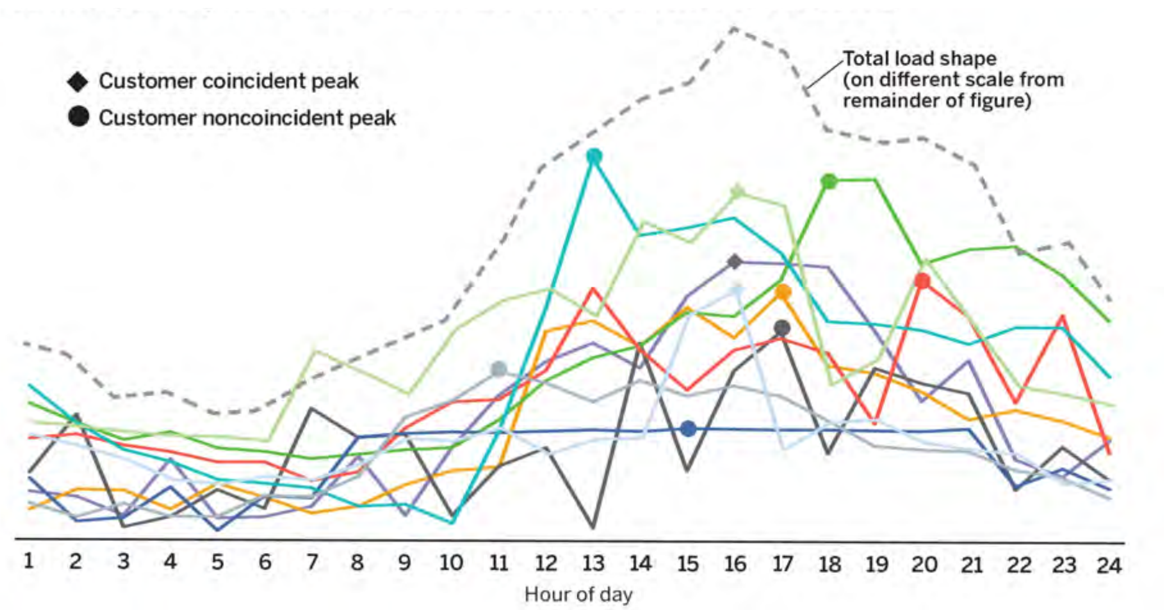
It is only when one gets close to the end user that the components of the system — the final line transformers, secondary distribution lines and service lines — are sized to meet a very localized demand that can be directly attributed to a small number of customers. Even at this level, there can be significant diversity among customers sharing a single transformer.

[29] Zarnikau, J., & Thal, D. (2013, September). The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market. *Utilities Policy, 26*, 1-6.

[30] To be more precise, we should say a "relevant component of the system" since different components of the system may hit peaks at different times. It's not unusual to see a systemwide peak occur at a particular hour on a particular day, but for individual elements of the subtransmission and distribution systems to hit peaks at other times. Expressing these peaks in prices and capturing each user's causal relationship to them is a challenge of time-varying rate design and, to the extent that this reflects different peaks in different areas of the system, may require locational distinctions as well. Precision is valuable, but complexity may produce inferior customer response.

Figure 3 shows actual data from a confidential load research sample on a summer peak day for 10 residential customers who share a line transformer. The total load shape is on a different scale than the individual customer loads.

Figure 3. Summer peak day load from 10 residential customers on one line transformer

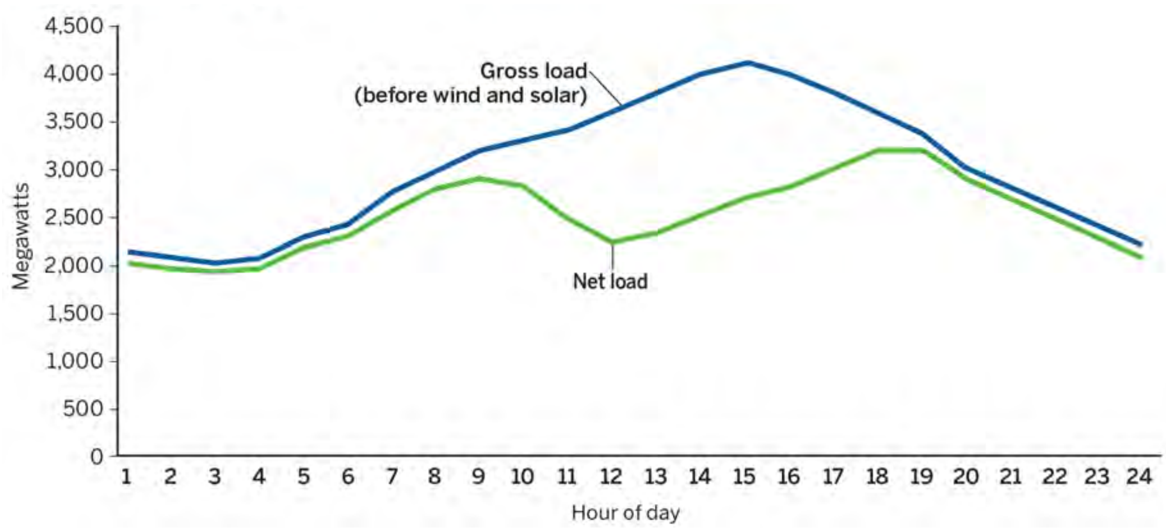


Source: Confidential load research sample

This demonstrates how diversity determines the need for the sizing of system elements. Only three of the 10 customers peak at the same time as the 4 p.m. coincident peak for the group, and the coincident peak is only 86% of the sum of the individual peaks on this day, which translates into a diversity factor of 1.16. This is just the variation on a particular high-load day. Although not shown in this figure, this coincident peak is only 64% of the sum of the annual NCPs for the individual customers, which translates into a diversity factor of 1.56.

At least two features of the modern electric system are changing the traditional argument that high-load-factor industrial customers should be subject to demand charges. First, the timing of traditional peaks and valleys, and by extension their effect on both short-run variable costs and longer-term capacity needs, is changing due to the increased prevalence of variable renewable resources. In regions where solar generation has increased rapidly, the “duck” curve is now a familiar phenomenon, as shown in Figure 4. Second, relatively low-cost on-site energy storage means that *all customers* have the potential for economically shiftable load and can respond to time-based price signals.

Figure 4. Illustrative net load curve



In such a situation, the benefits of shifting energy intensive industrial load from early evening to midday could be quite large. But this could mean *an increase* in the customer load factor, which is substantially discouraged by demand charges.

3.2 A Significant Portion of Capacity Investment Is Not Demand-Related

Traditional cost allocation terminology makes a distinction among demand-related, energy-related and customer-related costs. This terminology may obscure more than it illuminates. In particular, the term "demand-related" is often used to imply that demand charges are a proper pricing method for recovering costs so designated. Moreover, "demand-related" has typically referred to system peak demand and not individual customer peaks.[31] Other terminology, such as "peak-related," is more descriptive of the concept and avoids confusion with the use of "demand" in other contexts (such as "demand for energy").

[31] See Bolton, 1951, p. 132 (describing demand-related costs as "a cost proportional to system demand") and pp. 143-144 (describing how to spread costs across a wide number of potential system peak hours). In rate design, these same costs might be recovered through demand charges for certain customer classes. When determining the rate in dollars per kW, the total costs are then divided over the larger denominator of individual NCP demand, without accounting for load diversity within the class. This reduces the dollars per kW as charged to each customer from the dollars per kW used to assign costs to each class. This reduction is labeled differently in different jurisdictions, such as an "effective demand factor." However, this reduction is passed through to all customers and does not correct for differences in the timing of individual customer peaks. Customers who have demand highest at peak times receive a discount, and those who have demand highest at other times are overcharged.

Advocates for demand charges sometimes assert that most or all capacity costs are demand-related, which maximizes the size of the demand charge (if one is at all justified).[32] This leads to the large magnitude of the demand charges for industrial customer classes in many states. However, significant portions of capacity costs are not demand-related but are in fact incurred to meet energy needs. Investments in generation, transmission and distribution in the modern electric system may serve either of the two primary objectives of system planners, but the degree to which demand plays a role in each objective is different. These two goals are: (1) ensuring reliability (in both operational and investment time frames) and (2) meeting year-round system load at least cost. In many respects, reliability concerns arise predominantly at peak system hours.[33] Meeting system load at least cost, by its very nature, must consider usage patterns across every hour of the year. To meet these two objectives, system planning, investment and operation must jointly consider not only the engineering and physics of the electric system but also the economics of the relevant choices. We see this tension in the evolving landscape of capacity resources.

With respect to generation, most capacity costs may have been demand-related prior to the invention of the modern combustion turbine in the 1960s. In an electric system dominated by largely homogenous steam generation capacity, a MW of capacity built for peak demand could be used equivalently year-round.[34] In such a situation, generation capacity costs could be allocated and charged predominantly at peak times.

The existence of multiple different types of generation capacity, storage and demand response changes this analysis significantly.[35] Aggregate supply (generation, storage and demand response) must be sufficient for systemwide coincident peaks, as well as contingencies across many other hours of the year, such as when outages (unforced and even planned, such as nuclear refueling) combine with other circumstances (e.g., unusual weather) to push demand up against the limit of available resources.

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[32] See Faruqui, A., & Davis, W. (2016, July). Curating the future of residential rate design. *Electricity Daily*, 23. http://files.brattle.com/files/7137_curating_the_future_of_rate_design_for_residential_customers.pdf. The authors state that “a large share of a utility’s costs are actually driven by investment in infrastructure, such as generation capacity and transmission and distribution (T&D) networks. These costs are not directly related to the amount of energy that is consumed; they are, instead, driven by various measures of maximum electricity demand.” See also the description of an idealized rate design that “recover[s] capacity costs through demand charges” in Faruqui, A. (2019, June 1). 2040: A pricing odyssey. *Public Utilities Fortnightly*, p. 56.

[33] Reliability can be thought of as having two dimensions, in terms of both system security and resource adequacy. The former refers to operational time frames, being assured that the system has sufficient resources to meet demand in real time. The latter refers to investment time frames, being assured that the system will continue to deploy needed capacity to reliably serve load over the longer term. Both kinds of reliability are relevant to this discussion.

[34] Even this historic scenario is a substantial oversimplification due to significant level of hydro generation in many areas.

[35] Bonbright recognized this briefly in a footnote; see Bonbright, 1961, 354, fn 15. By 1970, this was a better understood and less theoretical concept so that Kahn spent multiple pages discussing it; see Kahn, 1970, pp. 97-98. M. A. Crew and P. R. Kleindorfer formalized mathematical models of optimal pricing with multiple different types of generation capacity; see Crew & Kleindorfer, 1979.

The optimal mix of resource types depends on the broader load patterns. Different generation technologies have different capabilities and different cost characteristics and should not be blindly lumped together as "capacity" for cost allocation and rate design purposes. The kind of capacity that one would build to meet short-term coincident peak needs, as well as reserves on short notice throughout the year, is much different than the kind of capacity that one would build to generate year-round. Indeed, for very infrequent needs, demand response (paying customers to curtail usage for a short period) is proving much cheaper than building *any* kind of generation resource that is seldom used. In order to be economic, capacity that serves only short-term needs must have low upfront investment costs, such as combustion turbines or demand response, but can have higher short-term variable costs when it is used. The combustion turbine is cheap to build but relatively inefficient and expensive to run. In contrast, a larger investment can only be justified by lower expected short-run variable generation costs and a higher expected capacity factor. As a result, this high-upfront-cost capacity lowers the total cost of both meeting peak demand and serving energy needs over the planning horizon.

So there is a trade-off between capacity costs and energy costs. Put simply, not all capacity costs are incurred to meet peak demand. As a result, capacity costs for generation should either be split into the traditional demand-related and energy-related categories, or else those categories should be updated into a more modern time-based classification framework.[36] Under any reasonable version of the demand-related classification, it is important to recognize that the capacity costs placed here are to serve relatively short-period peak reliability needs.

Even the appropriate short-period peak reliability capacity costs should be charged on a broader basis than the absolute peak hour of the year for several reasons. One is that, while planners and operators generally have a good idea of when a system peak is likely to occur, they by no means know for sure. Consequently, there is a reliability value to capacity in many hours that should be reflected in prices.[37] A second is that the actual peak can be influenced by pricing structures. For example, if a system peak could be reliably predicted for the 5 p.m. hour on a given day, charging a higher price at that single hour could just push that same peak to 4 p.m. without a meaningful reduction. This is the "whack-a-mole" problem. Taking both of these issues into account, some writers have referred to the relevant set of peak hours as the "potential peak" period.[38] This is a major consideration in the determination of on-peak hours for a TOU rate or a peak

[36] See Lazar, J., Chernick, P., Marcus, W., & LeBel, M. (Ed.) (2020). *Electric cost allocation for a new era: A manual.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

[37] The operating reserves demand curve mechanism in the ERCOT wholesale market is one means of establishing that value across the entire year. In many areas, the loss of load probability is relatively high for only 50-100 hours per year, which is the typical design criteria for critical peak pricing and demand response programs.

[38] Bolton, 1951, p. 143.

window demand charge. A related challenge is that different elements of the system (e.g., generation, transmission and distribution) may peak at different times, which should be accounted for to the extent possible.

Generation capacity also has some reliability value in off-peak hours. Generation reliability issues may come primarily at peak times but certainly not exclusively. This can be because of generator outages (both planned and unplanned), unusual weather, transmission outages, other operating constraints or a combination of the above. D. J. Bolton commented in 1951 that there had been several times that load needed to be shed in off-peak seasons because of generator maintenance, which was "a definite indication of demand-related expenses on account of generating plant" even in off-peak seasons.[39] A loss-of-energy-expectation study calculates the year-round generation reliability risks and is one of the best ways to allocate demand-related generation capacity costs (but not energy-related generation capacity costs) over the entire year.[40] A probability-of-dispatch method, alternatively, assigns the total costs of generation resources to the hours in which each resource provides service.

Many of these same considerations apply to the transmission and distribution system, and an analyst should look to the underlying purposes and benefits of system investments to allocate and charge them properly. Several different kinds of transmission capacity are intended to deliver energy and are not designed primarily to meet reliability needs. The transmission segment that connects a generating unit to the broader transmission network can be properly thought of as a generation-related cost and charged on the same basis as the underlying generator. In many situations, long transmission lines are needed to connect low-cost generation resources, such as remote hydroelectric facilities or mine-mouth coal plants, to the network. These long lines are built to facilitate access to cheap energy and should be classified on that basis. Last, transmission lines built to facilitate exchanges between load zones are not necessarily most highly used at peak times but are used to optimize dispatch and trade energy across many hours of the year.

Other parts of the transmission and distribution network do need to be sized to meet peak demand and other reliability contingencies. But there are several different engineering options for transmission and distribution networks that have implications with respect to line losses, another clear energy-related benefit.[41] There are generally two types of losses incurred across the transmission and distribution system: no-load losses and load losses. No-load losses are incurred primarily to energize transformers (both station transformers

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[39] Bolton, 1951, p. 143.

[40] Lazar et al., 2020, p. 132.

[41] See generally Lazar, J., & Baldwin, X. (2011). *Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/

and line transformers). Smaller transformers consume less energy in this respect, but overloaded transformers incur high load-related losses, so optimal transformer sizing saves energy.

The system planning considerations for load losses, also known as resistive losses, are more complex. These losses occur as electrical current flows through each element of the system. These losses manifest themselves in the form of heat and reduce the amount of useful power that can supply customer loads. This relationship is represented by the formula:

Load losses (in kW) = $I^2 \times R$

Where I = current (in amps) and R = resistance (in ohms)

Load losses can be decreased by reducing the resistance or reducing the current. Installing conductors with thicker metal wires is a simple way to reduce resistance, but these larger conductors are more expensive. Investments that reduce the current can, however, be much more effective because losses go up with the square of current. Any investment that reduces the current by 50% will reduce load losses by 75%, and any investment that reduces the current by 90% will reduce load losses by 99%. Since the current required to supply load is highest during peak demand periods, system losses are greatest during peak demand periods. There are several different types of capacity investments that reduce current substantially:

- Higher voltage lines: There is a direct relationship between the voltage of a line, the current passing through the line and the power delivered.
  - Current (in amps) = power (in kW)/voltage (in volts)
  - As a result, increasing the voltage by a factor of 10 reduces the current by 90%, which in turn reduces load losses by 99%.
- Siting substations closer to loads: By siting substations closer to loads, one can reduce the losses incurred by having conductors at lower voltages supply loads across long distances — the latter condition resulting in higher currents and relatively higher losses.
- Converting single-phase distribution lines to three-phase power: Three-phase power requires one additional conductor and additional space for the arrangement of the lines. For three phase lines, current = power/(voltage x √3). At the same voltage, current drops by 42.3% and load losses are reduced by two-thirds.
- Distribution level control of voltage and reactive power: Capacitor banks, smart PV inverters, voltage regulators and other more distributed assets across the system can compensate for voltage and reactive power needs at a local level that would

otherwise need to be met through the supply of upstream resources delivered through the grid — the latter condition resulting in higher currents and greater incurred losses.

- Optimizing the location and size of line transformers: Siting transformers closer to customers allows for shorter secondary lines that have low voltage and thus higher losses per foot. For some areas, this may require additional transformers, which comes at a cost. Smaller transformers also have lower no-load losses. Unfortunately, smaller transformers have lower rated capacities and thus higher load losses for a given level of current. Conversely, larger transformers have higher no-load losses but lower load losses. These complex economics should be analyzed to account for trade-offs between capital costs and energy losses. Modern advanced metering infrastructure (AMI) systems provide the ability to prepare heat maps on each transformer, enabling optimal sizing to minimize costs and losses.[42]

All of these factors should be accounted for in both cost allocation and rate design. Energy-related benefits from transmission and distribution capital investments are quite extensive. In a relevant sense, nearly all transmission lines are built with a substantial purpose of minimizing line losses for the delivery of large volumes of energy. Choice of the voltage level for a transmission line, either for a new line or upgrading an old line, involves higher capital costs for higher voltages with the counteracting benefit of lower losses. These costs are energy-related costs, not capacity-related costs. Furthermore, many of these energy benefits from investments to minimize line losses are not static over the course of the year. They increase dramatically at times of system peak because current delivered over the system is much higher, and marginal system losses at the time of peak can be 15-20% in many utility systems.[43] In addition, these benefits can be compounding because they are not limited to fuel costs or wholesale purchases. A more efficient transmission and distribution system can lower generation capacity requirements as well, including reserves.

All of these economic and engineering phenomena should be properly reflected in any analyses of cost causation. More specifically, these distinctions must be passed into rate design or else it gives rise to opportunities for customers to take inappropriate advantage by gaming the rates, with bill savings that far exceed any long-term reduction in system costs. The experience of the British Central Electricity Generating Board, a wholesale provider, provides a stark example of this in the late 1960s. The central board charged the regional boards for generation capacity costs based solely on a narrow peak window. In response, the regional area boards built their own combustion turbines at significantly lower cost to generate during these peak hours. This forced the central board to change its

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[42] See Lazar, J. (2018, October 18). *Smart grid and community benefits — with no rate increase? How Burbank made it happen.* Regulatory Assistance Project. https://www.raponline.org/blog/smart-grid-and-community-benefits-with-no-rate-increase-how-burbank-made-it-happen/

[43] Lazar & Baldwin, 2011, p. 4.

wholesale rates, charging for only marginal capacity costs in a short peak and charging for the bulk of capacity costs in a broader period.[44] The key insight in this scenario is that demand-related costs charged to peak times should only reflect the marginal costs of relatively cheap generation, storage or demand response capacity costs incurred for short-period peak reliability purposes.

Modern examples of this pricing problem can be found in the current practices of several independent system operators and generation and transmission suppliers. For example, ERCOT currently charges on the basis of the highest hour in each of the four summer months for recovery of embedded transmission system costs to distribution service providers. This type of pricing mechanism is inappropriate for transmission costs and furthermore distorts the operation of the wholesale energy markets by over-incentivizing a wide range of customer actions.[45] Similarly, many electric cooperatives, charged by their generation and transmission suppliers on the basis of NCP demand imposed on the wholesale supplier, have installed water heater control systems to mitigate this demand at much lower cost than the avoided demand charges. Since the generation and transmission demand charges include the cost of baseload units and transmission, they greatly overstate the value of localized NCP load reductions. While these are wholesale examples, the same economic proposition also extends to retail rates.

3.3 Time-Varying Energy Rates Are More Efficient Than Peak Window Demand Charges

Once one acknowledges the time-dependent nature of cost in the generation and delivery of electricity to end users on a shared system, one must necessarily acknowledge the superiority (as matters of economic efficiency and fairness) of prices that reveal to those end users that temporal variability in cost to those that do not. The question, then, is simple: What should those prices look like? In some sense, a peak window demand charge does recognize this time dependency. However, a comparison of the incentives presented by time-varying demand charges and time-varying kWh charges reveals why time-varying kWh charges are the better approach.

There are several types of time-varying energy rates to be considered today.[46] Key design choices for these rates include the number of time periods, whether the price for each time period is set long in advance or can itself vary based on system conditions and market

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[44] Kahn, 1970, pp. 97-98.

[45] See Hogan, W., & Pope, S. (2017, May). *Priorities for the evolution of an energy-only electricity market design in ERCOT*, pp. 69-79. Harvard University and FTI Consulting. https://hepg.hks.harvard.edu/publications/priorities-evolution-energy-only-electricity-market-design-ercot-0. We do not endorse the proposed solution of Hogan and Pope but agree with the transmission pricing problem that they describe.

[46] From this definition we exclude seasonal rates and kWh prices that vary from billing period to billing period. These kinds of rates can also reflect the cost-causation basis of rates but provide little or no incentive to manage usage within a billing period.

outcomes, and the actual prices for each time period.[47] The simplest is known as a time-of-use or time-of-day rate, which utilizes a small number of preset time periods and prices within each billing period. The most sophisticated time-varying rates are typically described as real-time prices, which are updated at short, regular intervals (e.g., hourly) based on prices in wholesale energy markets.

There are also options that combined preset time periods with pricing that varies based on system conditions in a predictable manner. With critical peak pricing, or the related peak-time rebate alternative, higher prices for times when the grid is stressed are set well in advance, but the days (and perhaps the hours) where these higher prices apply are actively chosen in response to system conditions. Variable peak pricing, as currently offered by Oklahoma Gas & Electric,[48] adds another layer of price differentiation by allowing more preset options for the on-peak price period. The on-peak price depends on market conditions: low, standard, high and critical. This choice between four different alternative on-peak prices allows for a higher level of precision in marginal incentives. All of these variations share a common goal — to improve the load shape for a utility by decreasing peak period load and shifting some of that to off-peak periods.

In this context, it is most natural to compare peak window demand charges with simple TOU rates because many of the key parameters can be kept constant. For both of these options, the peak time periods and the prices charged are set well in advance and can be set to recover the same categories of costs. Holding those two variables constant, peak window demand charges are inferior to time-varying kWh charges in that same peak window, as a general method for charging peak capacity costs, for two related reasons:

1. The inefficiency of the ratchet that all demand charges impose, which incorrectly underprices usage in the rest of the peak window within the billing period.
2. Unfair intraclass cost allocation, with those customers with demand diversity subsidizing those with more continuous usage.

Peak window demand charges can certainly elicit customer response and incentivize them

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[47] The options that are available in practice depend on metering technology, which has evolved substantially over time. In the early part of the 20th century, TOU rates could be implemented with meters that operated on timers, where one track would record on-peak usage every day and another track would record off-peak usage every day. No distinction based on weekends or holidays was possible. By 1941, more sophisticated versions were available with remote controls that could switch the meters between tracks on command. Since that time, many more innovations have occurred to enable different types of time-varying rates. Three-period TOU rates became common for large industrial customers in France beginning in the 1950s. With advanced metering infrastructure and a sophisticated data collection and billing system, the possibilities are nearly endless. Even without AMI, simple TOU meters have long been available that track on-peak and off-peak usage based on programmed timers, which can exclude weekends and holidays from on-peak periods.

[48] Oklahoma Gas & Electric. (2018, June 18). *Standard pricing schedule: R-VPP variable peak pricing.* https://www.oge.com/wps/wcm/connect/c41a1720-bb78-4316-b829-a348a29fd1b5/3.50+-+R-VPP+Stamped+Approved.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-c41a1720-bb78-4316-b829-a348a29fd1b5-mhatJaA

to shift load from inside to outside that window.[49] Nevertheless, peak window demand charges share many of the faults of traditional monthly demand charges, just on a different scale. Once again, the key distinction is between the consistent and symmetric marginal incentive of a time-varying kWh rate and the arbitrary effects driven by the demand charge's ratchet.

A close examination of customer behavior reveals why energy-based prices are preferable to demand charges even within a peak window. In any system with significant customer diversity, a large number of customers will not have their individual peaks at the time of the system's peak. Still, it could be that a substantial number of customers peak at the time of the system peak. The proportion of one to the other matters if demand charges are to have a significant linkage to the system peak. Customers who are at risk of setting the individual peak for the demand charge face a high marginal price for consumption, but those who are not face a lower marginal price. This proportion will vary from service territory to service territory and over time as technology evolves.

Customer behavior under a peak window demand charge would likely even vary based on completely arbitrary factors. That could be whether certain customers are at the beginning of their billing period or whether a significant event that led a customer to incur a largely unavoidable peak (e.g., hosting a party during a peak window) happened before that very high-load time. This randomness can be entirely avoided. The fair and efficient solution is to continue to treat all consumption as marginal, a condition that is achieved by time-varying kWh rates.

In the absence of technology that automates response to changes in prices, the ratchet problem for peak window demand charges may be diminished by the inability of customers to respond accurately to its incentive structure. It is unlikely that people going about their daily lives can do more than respond to the broad incentives provided by either an on-peak kWh price in a simple TOU rate or a peak-window demand charge. In both cases, the easiest answer may very well be just "consume less during the peak window period."[50] This could mitigate the harm posed by the ratchet, but it also begs the question about the underlying rationale if there is no customer response.

A modest subset of residential customers may be able to respond to the next rule of thumb presented by a peak window demand charge: to operate as few end uses as possible simultaneously. Fully responding to the incentives posed by a demand charge requires

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[49] See, for example, Stokke, A., Doorman, G., & Ericson, T. (2009). *An analysis of a demand charge electricity grid tariff in the residential sector.* (Discussion Paper No. 574). Statistics Norway, Research Department. https://ideas.repec.org/p/ssb/dispap/574.html

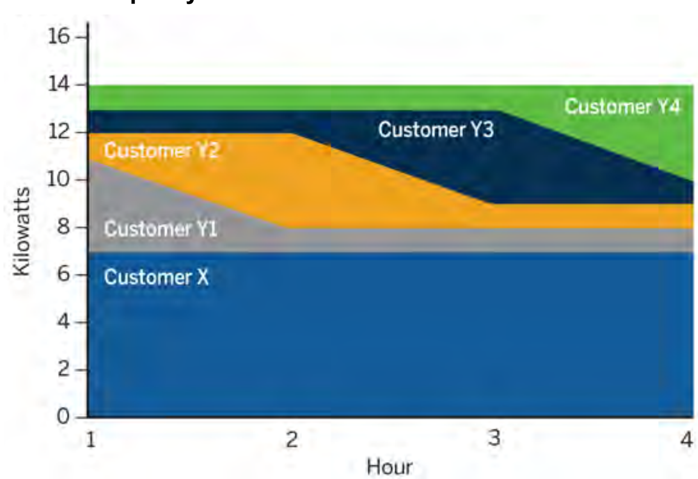
[50] For example, the Mid-Carolina Electric Cooperative has a three-hour peak window demand charge for residential customers. On the relevant page of its website, the peak window demand charge is labeled as an "on-peak charge." None of the advice given to manage this rate is specific to the actual working of a demand charge and could equally apply to a three-hour on-peak kWh rate. Mid-Carolina Electric Cooperative. (n.d.). *Rate structure.* http://www.mcecoop.com/content/rate-structure

customers to track their demand and know whether they are currently at risk of setting a high demand for the billing period — too much to ask of many residential and small business customers.

However, energy management technology, enabled by software and "supercharged" by on-site storage, will be able to adjust usage in a far more responsive manner than ordinary people could manage alone. Such energy management is likely feasible today for larger customers and could very well be widely feasible for smaller customers in the next few years. At least one company, Energy Sentry (http://energysentry.com/index.php), has developed a residential "demand controller" that automatically sheds less critical loads (water heaters, clothes dryers) when priority loads (microwaves, coffee makers, hair dryers) are activated. Such technology would allow customers to respond more effectively — *from their perspective* — to the incentives provided by a demand charge. But that is not to say that the overall efficiency of the electric system will be improved, since customer responses to demand charges do not typically optimize use of the system.

Peak window demand charges also create intraclass cost allocation problems, which are linked closely to the above efficiency concerns. Peak window demand charges still overcharge the low-load-factor customer and undercharge the high-load-factor customer. This is illustrated in the case of several smaller customers whose aggregate consumption adds up to the load of a single larger customer. Such a hypothetical is shown in Figure 5 for a four-hour peak period.

Figure 5. Customer load comparison illustrating ability to share capacity



Customers Y1, Y2, Y3 and Y4 have, in the aggregate, the same load profile as Customer X. Each of the Y customers has a peak of 4 kW for a total billing determinant of 16 kW under a peak window demand charge. However, Customer X has a peak of 7 kW, which translates into a billing determinant of 7 kW under a peak window demand charge. This means that Customer X is charged less than half the amount that the Y customers are for the *exact same aggregate load pattern*. The four diverse customers can efficiently share capacity and should not be penalized by a price structure that fails to account for their diversity. Time-varying energy-based charges solve this problem.

Peak window demand charges, though an improvement on monthly NCP demand charges, still come up short in the effort to send accurate information to consumers about peaks and other high-cost events. The occurrence of a peak cannot be known in advance, and, indeed, its timing depends in part on price structure. Shifting hours within a peak period does not necessarily lower the overall peak. Figure 6 is a comparison of two customers with equal kWh consumption in the peak period, one with a flat consumption throughout that period and another that varies.

Figure 6. Comparison of two customers

Compared with Customer X with a flat load pattern, Customer Z with the varying load pattern likely increases the chance of a system peak in hour 2, but by the same token likely decreases the chance of a system peak in hour 3. But the reverse can be said for Customer X compared with Customer Z: Customer X raises the likelihood of a system peak in hour 3 and decreases the likelihood of a system peak in hour 2. Advocates of demand charges consistently fail to explain why these types of discrepancies are justified by cost considerations.

Even well-designed TOU rates do not necessarily reflect critical peak times very well. For example, a four-hour weekday on-peak window for only the highest demand months will include around 200-400 hours annually. These will necessarily contain some days with higher peaks than others and only a limited number of hours that define utility capacity needs for reliability purposes at peak. Simple TOU rates do not distinguish in this regard between the moderate peaks (e.g., ordinary days in the summer) and the very highest peaks (e.g., extremely hot days in the summer). In short, the implication is that simple TOU rates do not provide a sharp enough incentive on actual peak days.[51] In any case, we are no longer bound to simple TOU pricing. Dynamic rates, including critical peak pricing, peak-time rebates, variable peak pricing and real-time pricing, all better address peaking issues because they provide higher marginal prices at the times of maximum system stress. By concentrating customer attention on the hours that actually drive costs, the more dynamic rates produce better results for the electric system and society.

By its very nature, a demand charge cannot present symmetric and consistent marginal incentives in the same way as a time-varying kWh charge. Compared to traditional demand charges, properly sized peak window demand charges have a better cost causation

[51] This is referred to as the needle-peaking problem in Crew & Kleindorfer, 1979, p. 186.

basis because they can be linked to the time periods that drive higher system costs. Daily as-used demand charges[52] applied to peak windows could be a further improvement on peak window demand charges, and, better yet, these peak window daily-as-used demand charges could fluctuate according to system conditions. However, this is only an improvement because it converges on the better solution, a system of time-varying kWh rates. Given the rate design possibilities that AMI offers, what reason is there to retain demand charges at all?

4. What Might Be Left for Demand Charges?

The foregoing demonstrates that the typical argument for demand charges, as used for generation, transmission and shared distribution capacity, is substantially flawed. Even so, we want to investigate if there are any circumstances, however limited, for which demand charges are an efficient rate design.

Some theorists have identified a different and, in our minds, much narrower set of rationales for demand charges. The case for time-varying rates relies substantially on the diversity of load and the lack of a direct relationship between individual customer peaks and the system peaks that drive costs. A diverse set of customers may, in the aggregate, create a predictable load profile much of the time. But what if this diversity goes away in an unpredictable manner? Or, for that matter, in a predictable one? Is there something about the causation of costs in special and *limited* circumstances that warrants charging for peak incurrences of short-term (e.g., 15-minute) demand for individual customers? To answer this question, we consider three cases that, on their faces, might present a marginal-cost justification for demand charges. The first is one that we have carved out from the beginning: capacity costs that are not shared, such as dedicated transformers and service drops, which we term “dedicated site infrastructure.”[53] This illustrates some important issues relevant to any broader theoretical case for demand charges. The second is the cost associated with uncertainty in customer behavior. The third is timer peaks, a phenomenon where customers shift usage in response to hours with lower prices.

[52] RAP authors, writing with partners from Synapse Energy Economics, previously recommended daily-as-used demand charges for standby service to large combined heat and power customers, as an alternative to monthly standby demand charges. The purpose was to recognize that different combined heat and power customers would have scheduled and forced outages on different days and could share the same capacity to provide their standby service. This was certainly an improvement on monthly demand charges for such customers, but, in light of the progress made in metering and time-varying energy-based rate structures, there’s every reason to think today that such time-varying energy rates are equally appropriate to customers with on-site generation. Johnston, L., Takahashi, K., Weston, F., and Murray, C. (2005, December 1). *Rate structures for customers with onsite generation: Practice and innovation*. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy06osti/39142.pdf

[53] RAP has previously recommended a small transformer or site infrastructure demand charge for secondary voltage customers, particularly those customers with dedicated site infrastructure. See Lazar, J., & Gonzalez, W. (2015, July). *Smart rate design for a smart future*, pp. 53-54. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

4.1 Dedicated Site Infrastructure

Dedicated transformers and service drops for individual customers are, by definition, not shared infrastructure. The relative importance of this category of cost will vary by customer class. Larger commercial and industrial customer classes, as long as they are taking secondary voltage service, will often have dedicated transformers for each customer or a dedicated transformer bank for customers taking three-phase power. Dedicated transformers will be rare for residential customers in urban and suburban areas, but single-family homes will almost always have a dedicated service drop. The largest industrial customers may have their own primary line (effectively serving as a dedicated service drop) or a dedicated substation (effectively serving as a dedicated transformer). In rural areas, each customer will typically have a dedicated transformer, at which point transformers are customer-specific site infrastructure.

For these customer-specific site infrastructure costs, there is no diversity of demand between the customer meter and point of connection with the shared system. As a result, individual customer NCPs are certainly relevant to the sizing of these components. One might conclude from this that a demand charge can provide a reasonable pricing incentive here. The time period for such a demand charge should have nothing to do with a shared peak since there is no sharing of the infrastructure. Nor should it be limited to peak windows since the peak for an individual customer could occur at any time. The cost of these components may be no more than about $1/kW/month, a fraction of typical demand charges.[54]

There are also other ways of efficiently pricing this category of costs. A similar set of customer incentives may be presented by a connected load charge for a set amount of local capacity. Such a connected load charge can help with efficient sizing, but only if it's accompanied by a fee for overages or the automatic tripping of circuits when demand would cause an overage. Even then, a connected load charge provides no incentive for customers to manage their usage efficiently; that is, there are no cost savings to be gained by keeping their demand below the level of the predetermined connected load. A charge that establishes the relationship of the customer's individual peak demand to the sizing of these components might, however, give the customer some incentive to minimize peaks.

It is worth examining this issue at the level of engineering and planning. What type of customer behavior would minimize the risk of transformer overload and degradation? Or what type of customer behavior would allow utilities to size dedicated transformers more efficiently?

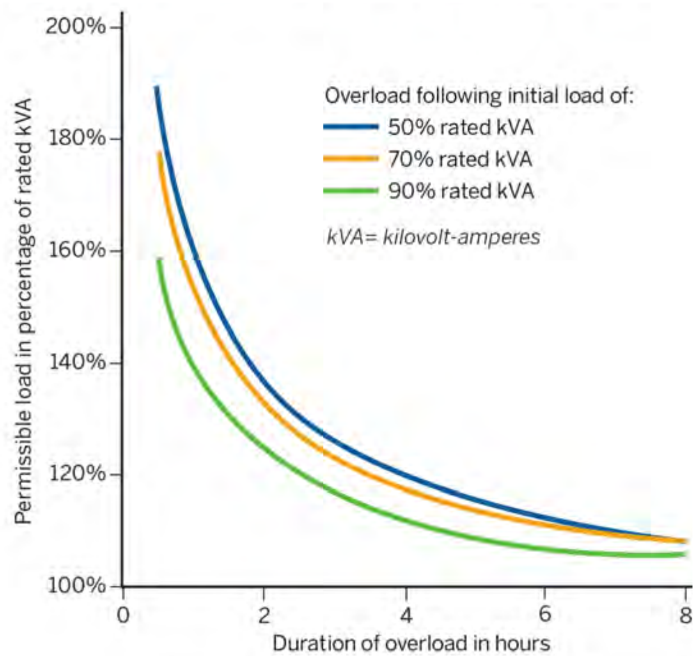
Capacity ratings for the different elements of the electric system are set with many

[54] Seattle City Light, for example, has a large general service rate with specific charges for transformer investment; these are $0.27/kW/month. Seattle City Light. (n.d.). *City Light rates.* https://www.seattle.gov/light/rates/summary.asp

engineering limits in mind. Many of the most important considerations revolve around the heating — and overheating — of components, particularly transformers and conductors. This has a number of different implications. For example, effective delivery capacity can be higher in the winter than the summer or higher in the cool nighttime than during the sunny daytime. The capacity ratings for individual system elements are for sustained loads in typical conditions, but loadings can exceed those ratings on a regular basis without necessarily incurring significant damage. As Tom Short colorfully puts it, a conductor rated 480 amps "will not burst into flames at 481 [amps]."[55]

Figure 7[56] demonstrates the maximum overload that a transformer can take without shortening its operating life, by examining two primary variables: (1) the initial load prior to any overload and (2) the duration of an overload. If a transformer has had light loads (50% of its rating), it can sustain a short-term overload of nearly 190% or a four-hour overload of just over 120%.

Figure 7. Permissible transformer overloads for varying periods



Source: Bureau of Reclamation. (1991). *Permissible Loading of Oil-Immersed Transformers and Regulators*

The important question then is what kind of rate design incentivizes optimal customer behavior with respect to this equipment. Panagiotis Andrianesis and Michael C. Caramanis have developed an algorithm for dynamic nodal locational marginal costs for distribution systems that offers an intriguing approach to pricing for these customer-specific facilities. For line transformers, the pricing formula is a real-time price per unit of energy that follows the transformer thermal response dynamics, which is essentially the temperature of the cooling oil in each transformer.[57] Similarly, a critical peak energy charge could apply for the few hours per year when a transformer is

[55] Short, T. A. (2004). *Electric power distribution handbook*, Section 3.5, p. 140. CRC Press.

[56] Bureau of Reclamation. (1991). *Permissible loading of oil-immersed transformers and regulators.* https://www.usbr.gov/power/data/fist/fist1_5/vol1-5.pdf

[57] Andrianesis, P., & Caramanis, M. (2019). *Distribution network marginal costs: Part 1, A novel AC OPF including transformer degradation.* arXiv. https://arxiv.org/abs/1906.01570

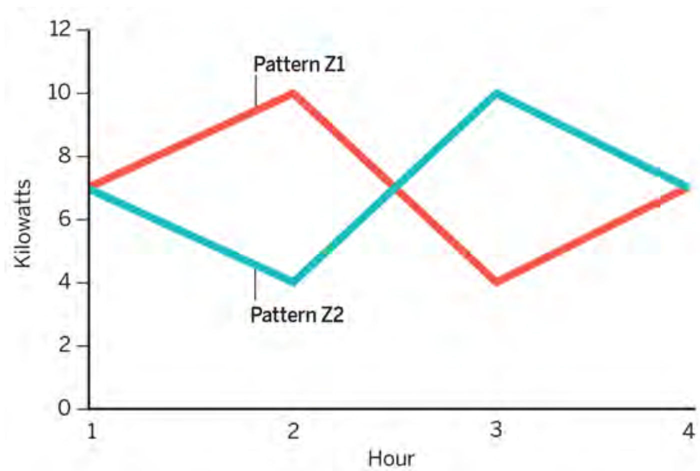
stressed but would require real-time monitoring and pricing to be applied on a transformer-by-transformer basis.

This type of short-run marginal cost pricing does not resemble a demand charge and has the virtue of linking closely in time the incurrence of high marginal costs to the prices charged. These approaches are quite sophisticated and could be costly to administer. To achieve a rate that is more feasible now, a simpler structure would be necessary. A daily-as-used demand charge or a traditional monthly demand charge, based on 15-minute or 30-minute peaks, could certainly discourage the extremely high short-term peaks that would damage a transformer. Those options might not do enough, however, to discourage a sustained, multihour overload.

4.2 Risks of Customer Variance at Peak Times

Load diversity isn't static and can fluctuate in ways that are both predictable and unpredictable. Predictable changes often occur around the weather, one of the few variables that simultaneously affects all customers in a given area. Regarding unpredictable changes, consider a simple hypothetical illustrated in Figure 8.

Figure 8. Two hypothetical load patterns randomly chosen by customers



If there are 10 "random-load" customers who flip a fair coin to determine whether their load profile corresponds to either Z1 (heads) or Z2 (tails) in Figure 8, the average load in each hour across a large number of trials will be 70 kWh.[58] However, system planning must not only deal with the expected average load but rather the chances of higher load. Unfortunately, in any given trial of this scenario, the probability of five heads and five tails — leading to a demand of 70 kW in every hour — is only 24.6%. There is a small but nonzero chance that every customer gets either heads or

[58] In this illustrative example, we consider each customer to have a flat load within each hour. This means that kW and kWh are largely interchangeable as units. Similar examples could, however, be constructed with demand varying in smaller increments (e.g., 30, 15 or 5 minutes), and similar results could be obtained.

tails, leading to a 0.2% probability of a peak load of 100 kW. The full spectrum of potential results for this hypothetical scenario with 10 random-load customers is shown in Table 1.

Table 1. Peak load and probabilities for 10 random-load customers

Coin flip result	High load: Number of customers	Low load: Number of customers	Peak load (kWs)	Probability
10 heads or 10 tails	10	0	100	0.2%
9 heads or 9 tails	9	1	94	2.0%
8 heads or 8 tails	8	2	88	8.8%
7 heads or 7 tails	7	3	82	23.4%
6 heads or 6 tails	6	4	76	41.0%
5 heads and 5 tails	5	5	70	24.6%

The cumulative odds of a peak of 88 kWh or higher is 10.9%, and a peak of 82 kWh or higher is 34.4%. In this hypothetical scenario, it is clearly beneficial to have customers flatten their load curves to 7 kW every hour within this time period. Table 2 shows the range of possible results and associated probabilities for six random-load customers corresponding to either pattern Z1 or Z2 and four flat-load customers with a demand of 7 kW in each hour.

Table 2. Peak load and probabilities for six random-load and four flat-load customers

Coin flip result	High load: Number of customers	Low load: Number of customers	Flat load: Number of customers	Peak load (kWs)	Probability
6 heads or 6 tails	6	0	4	88	3.1%
5 heads or 5 tails	5	1	4	82	18.8%
4 heads or 4 tails	4	2	4	76	46.9%
3 heads and 3 tails	3	3	4	70	31.3%

The risk of a peak of 88 kW or higher drops from 10.9% to 3.1%, and the risk of a peak of 82 kW or higher drops from 34.4% to 21.9%. If the customer choices are uncorrelated, this type of risk goes down as the number of customers increases.[59] However, if the customer choices are correlated, between hour 2 and hour 3 in this hypothetical, the risk does not necessarily decrease with a higher number of customers.

[59] The ratio of the variance to the expected total decreases in proportion to the square root of the number of customers.

This simple example is the essence of the argument made by Michael Veall.[60] He demonstrates that, for a given level of average customer demand during a peak, higher variance customers lead to a risk of higher peaks, particularly if they are correlated. This, in turn, results in a need for higher capacity planning margins. Veall constructs a detailed economic model of optimal peak period pricing. He states that the traditional monthly demand charge does not reasonably address this issue, but rather a peak window demand charge can serve as marginal price on a customer's variance. He notes additional caveats: "If there are many small users with uncorrelated demands, the effects of an individual user's variation on total system variation will be small. But if users are large or their demands are correlated, variance charges are important."[61] Finally, Veall's result demonstrates that, if a peak window demand charge is to be imposed, it should be paired with an on-peak kWh rate.[62] The logic around risk and Veall's theoretical model present an argument for a peak window demand charge that is substantially different from those that utilities put forward. And again, we see a more defensible justification for peak window demand charges for larger-volume customers. But the key question of correlations and *levels of risk* has been neglected in the discussion around demand charges and is only a theoretical possibility in Veall's model. Furthermore, Veall's model does not consider the possibility of more granularly dynamic time-varying kWh rates.

Marcel Boiteux, the influential French economist and executive for Électricité de France (EdF), does discuss risk and uncertainty in a 1952 paper, written jointly with his colleague Paul Stasi.[63] When it comes time for tariff design, Boiteux and Stasi describe two different zones of the shared electric system: (1) the "collective network" and (2) the "semi-individual network, whose capacity depends particularly on the uncertainties of consumption of each customer."[64] With respect to the collective network, they find that the "uncertainties of individual consumption" are small enough to be ignored.[65] And, finally, their analysis of the "semi-individual network" is dominated by risk and the irregularities of individual customer's loads. This leads them to a justification for a complex system of subscription-based contract demand charges, with higher prices for contracted demand in

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[60] Veall, M. (1983). Industrial electricity demand and the Hopkinson rate: An application of the extreme value distribution. *The Bell Journal of Economics, 14*(2), 427-440.

[61] Veall, 1983, p. 429.

[62] Veall, 1983, p. 431. Veall notes that this on-peak kWh price could, in principle, even be negative, which would be a curious result.

[63] Boiteux, M., & Stasi, P. (1964). The determination of cost of expansion of an interconnected system of production and distribution of electricity. In J. Nelson (Ed. & Trans.). *Marginal cost pricing in practice.* Prentice Hall. (Original work published in 1952).

[64] Boiteux & Stasi, 1964, p. 117.

[65] Boiteux & Stasi, 1964, p. 117

peak periods and lower prices in other periods. However, Boiteux and Stasi offer little but generalities as to the demarcation of the semi-individual network:

> The extent of the zone within which the uncertainties of individual demands have a very marked influence on the collective cost is greater in proportion to the irregularity of the demands considered, and to the correlations among these demands. This extent depends also on the density of consumption, for the number of customers supplied from a given node plays an important role in the "reduction of uncertainties."[66]

Based on these considerations, Boiteux and Stasi largely describe the generation and transmission system (150-220 kV) as the "collective network" and the distribution system (15-60 kV) as the "semi-individual" network.[67] They are discussing these issues in the context of the then-new Tarif Vert for high voltage industrial customers, and the discussion could be read in a manner that is limited to those customers. This could mean that the dividing line for the semi-individual network could vary by the size of customer. Whether residential customer fluctuations are correlated in a significant and pertinent way is another empirical question Boiteux and Stasi do not address. It is unclear whether the irregularities of individual residential customers would ever be significant enough to matter at a level higher than a shared transformer.

4.3 Timer Peaks

Michael A. Crew and Paul R. Kleindorfer (1979) raise another area where a demand charge could theoretically be efficient, which they describe as the secondary preferences of customers, given the structure of time-varying rates, and the shifting of demand to notionally off-peak times. This is colloquially known as a timer peak. This occurs if customers increase their usage substantially during hours with low rates or more specifically right at the time when low-priced hours begin.[68] In the worst-case scenario, TOU rates can theoretically just shift the system peak without reducing it if enough usage is shifted to hours with low prices. The same is true of coincident peak window demand charges. This outcome can be avoided by managing the number of periods in the rate, the hours covered by each period and the relative prices. One utility has designed a TOU rate in which each customer chooses a three-hour peak period of 4-7 p.m., 5-8 p.m. or 6-9 p.m. All of these customers have 6-7 p.m. in their peak period; two-thirds of them have 5-6 p.m. and 7-8 p.m. in their peak period; and one-third have either 4-5 p.m. or 8-9 p.m. in their

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[66] Boiteux & Stasi, 1964, p. 123

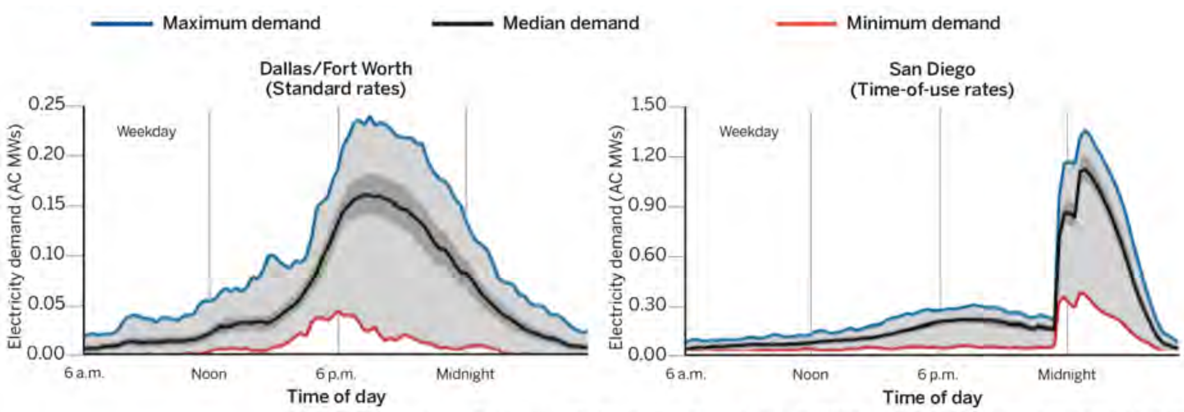
[67] Boiteux & Stasi, 1964, p. 110.

[68] Bonbright mentions this as a possible objection to time-of-use rates. See Bonbright, 1961, p. 362, fn 23: "In Chapter 10 of his book already cited in footnote 10, Davidson suggests this type of rate [time of day and time of season] as preferable to the familiar Hopkinson-type rate. But among the objections to it is the danger that its sharp breaks will create surges in the loads imposed on a power station or on a distribution line."

peak period. This provides the utilities with the most powerful pricing signal during the most likely peak hour but substantial peak reduction in the adjacent hours.[69] Another simple solution is to apply different hours to different classes or subclasses. For example, single-family residences may have their tariff shifted one hour earlier than apartments, or secondary general service one hour later than primary general service.

If the more general system peaks are not impacted significantly enough by this phenomenon to warrant changing the structure of the rate, more granular and local issues can theoretically arise. Figure 9 shows a set of results from a San Diego Gas and Electric rate for electric vehicles, where the "super off-peak" rate begins at midnight.[70]

Figure 9. Real-world illustration of timer peak with EV charging on TOU rate



Source: Jones, B., Vermeer, G., Voellmann, K., & Allen, P. (2017). *Accelerating the Electric Vehicle Market*

This is a rational customer response to a TOU rate, at least for specific end uses. If an electric vehicle is parked at home in the evening and will not be used again until morning, then the customer has a significant amount of flexibility to choose when charging will begin. The very beginning of the lowest price period is an obvious time to start charging. While this may not present an issue at the generation and transmission level, assuming midnight remains an off-peak period, bunching of EV charging could lead to issues at the more local level.

Again, thinking about a line transformer helps focus the analysis. If five single-family homes are served by one shared transformer and all five of those homes have EVs that start charging at midnight, then impacts at the line transformer level are a possibility. Furthermore, what if those houses have other timed usage that starts at the beginning of the lowest price period? Sending a secondary price signal that discourages households

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69 Salt River Project. (n.d.). *SRP EZ-3 price plan.* https://www.srpnet.com/prices/home/ez3.aspx

70 Jones, B., Vermeer, G., Voellmann, K., & Allen, P. (2017). *Accelerating the electric vehicle market*, p. 16. M.J. Bradley & Associates. https://www.mjbradley.com/sites/default/files/MJBA_Accelerating_the_Electric_Vehicle_Market_FINAL.pdf

from turning on all of their major end uses at midnight could be effective. A daily-as-used demand charge can send such a signal if it were applied across 24-hour periods. A more traditional monthly demand charge, however, will send that signal in a much more attenuated way. A connected load charge based on a contract demand for the cost of connection, with fees for overages, similar to the Électricité de France Tempo rate for residential customers,[71] would send a similar price signal as well.

There are other ways to deal with this phenomenon besides price signals with demand-charge features. The beginning of the off-peak period with the lowest price could be staggered for different customers, for example, beginning at 10 p.m. for one-third of customers, midnight for another third and 2 a.m. for the last third. For customers with long-duration controlled loads, like water heaters or electric vehicles, this would be easy for the customer to manage and beneficial to the utility. To maximize the benefits of such an approach, one would need to have a relatively even split among those three options for the customers on each shared transformer. Load management programs and smart devices could deal with this type of issue as well. For some loads, particularly water heating and EV charging, we anticipate advanced devices that will enable the utility to manage loads to minimize costs and enable customers to benefit from even lower off-peak rates for enabled devices.

One could even question how much of a problem this poses to the longevity of the shared transformers in question. The ambient temperature has almost always cooled off by midnight, and several hours of low or moderate loads could allow the transformer to cool from significant levels of usage during the day or early evening. In certain circumstances, it could be more convenient and cost-effective to upgrade any potentially affected transformers, particularly where multiple water heaters or EV chargers are served from a single transformer.

5. Conclusion

Demand charges, of either the traditional monthly NCP or peak window variety, are not efficient, as a general matter, for shared system capacity costs because:

- For the vast majority of customers, any peak reduction signal in a traditional monthly demand charge is weak and inaccurate.
- Traditional calculations for demand charges have included far too many costs as demand-related. Ideally, utility commissions will adopt a new time-based classification

[71] Electricite de France. (n.d.). *Tarif Bleu: Regulated sale tariff for electricity*. https://particulier.edf.fr/en/home/energy-and-services/electricity/tarif-bleu.html

and allocation framework for generation, transmission and shared distribution costs.[72] Failing that, the numerous energy benefits from capacity investments should be properly accounted for — that is, reflected in energy, not demand, charges.

- Simple TOU rates are superior to peak window demand charges in their own right, but AMI enables time-varying energy charges, such as critical peak pricing, peak-time rebates and variable peak pricing, that much more accurately target times of system stress and reward end users for shifting their loads to off-peak times.

Although we have shown the significant downsides to using current forms of demand charges, in very limited circumstances there might be cost- and efficiency-related justifications for certain types of demand charges. But such charges would be significantly lower than those prevailing for industrial customers in the United States today. Dedicated site infrastructure is a small portion of utility system costs, and typical demand charges would not necessarily provide an optimal signal to control these costs. The primary concerns around timer peaks are almost certainly limited to local infrastructure.

As for the general risk of customer variance and correlation, little work has been done to investigate the statistical bases of this more sophisticated case for demand charges. We think that it is unlikely that such an analysis would find that a substantial demand charge would be fairer or more efficient than time-varying energy charges. Lastly, there is a better case for demand charge-like structures for large customers, who are more likely to have significant dedicated site infrastructure. One might also argue that high variance at peak times among these customers has a more significant chance of influencing the overall system peak. Any such demand charges may not look like Hopkinson rates and would likely be only a second-best solution to a sophisticated system of time-varying energy charges.

The economic and regulatory principles that underlie these judgments are not new. The inescapable essentials of microeconomic theory are at work here. Boiteux, Bonbright and Kahn follow these principles and theories, as do the other scholars and practitioners we cite. In 1964, Paul Garfield and Wallace Lovejoy[73] also stepped into the fray. They converted principles of economic efficiency and fairness into straightforward criteria for assessing the merits of cost allocation methods and rate designs for generation and delivery capacity costs:

- All utility customers should contribute to capacity costs.
- The longer the period of time that customers preempt others' use of capacity, the more they should pay for the use of that capacity.

[72] Lazar et al., 2020.

[73] Criteria adapted from Garfield, P., & Lovejoy, W. (1964). *Public utility economics,* pp. 163-165. Prentice Hall.

- Any service that makes exclusive use of a portion of capacity should be assigned all of the costs for that portion of capacity.
- The allocation of capacity costs should change gradually with changes in the pattern of usage.
- More capacity costs should be allocated to on-peak usage than off-peak.
- Interruptible service (or other forms of utility restrictions and control) should be allocated less in capacity costs as the degree of restriction increases.

Only time-varying energy charges can meet all of these objectives simultaneously. Demand charges for shared costs are demonstrably less efficient and less equitable than they.

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	U-20836

PROOF OF SERVICE

On the date below, an electronic copy of Direct Testimony of Douglas B. Jester on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan and Exhibits MEC-1 through MEC-13 was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

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