OLSON, BZDOK & HOWARD

June 22, 2021

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

RE: MPSC Case No. U-20963

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-10; and

Proof of Service.

Sincerely,

Christopher M. Bzdok
Chris@envlaw.com

xc: Parties to Case No. U-20963

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	U-20963 ALJ Sharon Feldman

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TESTIMONY OF DOUGLAS B. JESTER

ON BEHALF OF

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

June 22, 2021

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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 a Partner of 5 Lakes Energy LLC, a Michigan limited liability corporation, located at Suite 710, 115 W Allegan Street, Lansing, Michigan 48933.

Q. On whose behalf is this testimony being offered?

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

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 (DJ-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 2020 Voluntary Green Pricing);
- Case U-20940 (DTE Gas 2021 Rate Case);
- Case U-20889 (Consumers Karn Retirement Securitization); and
- Case U-20995 (UPPCO Transfer of Control).

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 Cases 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 Case No. 20A-0204E and Case No. 20A-0195E 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, CUB, NRDC, and SC with a particular focus on the reliability and affordability of Consumers Energy's electric service for its residential customers. I address these issues as they relate to return on equity, test year projections, cost of service, and rate design.

Q. **Are you sponsoring any exhibits?**

A. Yes, I am sponsoring the following exhibits:

- Exhibit MEC-1 (DJ-1): Resume of Douglas Jester
- Exhibit MEC-2 (DJ-2): Citizens Utility Board of Michigan, Utility Performance Report, 2020
- Exhibit MEC-3 (DJ-3) Consumers Energy Comparative Performance
- Exhibit MEC-4 (DJ-4) Consumers Energy's Response to MEC-CE-373 and Attachment
- Exhibit MEC-5 (DJ-5) Consumers Energy's Response to MEC-CE-406

- Exhibit MEC-6 (DJ-6) Consumers Energy's Response to MEC-CE-489 with Attachment 1
- Exhibit MEC-7 (DJ-7) IEEE/ANSI Standard C57.91-1995 to -2001 redline
- Exhibit MEC-8 (DJ-8) Consumers Energy's Responses to MEC-CE-486 and MEC-CE-488
- Exhibit MEC-9 (DJ-9) Excerpt from Regulatory Assistance Project Cost Allocation Manual, Chapter 11
- Exhibit MEC-10 (DJ-10) Consumers Energy's Response to MEC-CE-376

II. SCOPE OF TESTIMONY

Q. What topics are you addressing in your testimony?

A. I will be providing an overview of the case that should frame the Commission's approach to it and then discussing Consumers Energy's overall performance in relation to the return on equity that the Commission should authorize. I will also discuss Consumers Energy's approach to projecting test year costs, the allocation of distribution system costs in the cost-of-service allocation study, and residential rate design.

III. OVERVIEW OF CASE AND CONSUMERS ENERGY'S PERFORMANCE

Q. Please summarize what you consider to be the key elements of this case.

A. Consumers Energy witness Michael A. Torrey summarizes the case for the Company.[1] Consumers Energy seeks a $225 million increase in jurisdictional revenue consisting of $121 million based on investments, $53 million based on the Company's proposed increase

[1] Direct testimony of Michael A. Torrey 5:8 – 6:17.

in cost of capital, and $76 million increase in operating expenses, offset by $25 million in increased sales revenue. He justifies the increased investment as driven by the Company's expenditures for new solar generation as part of a transition to clean energy and by the Company's "long-term electric distribution system strategy as presented in Case No. U-20134 in the Electric Distribution Infrastructure Investment Plan ("EDIIP")."[2]

Exhibit A-16, Schedule F2.0 page 2 of 3 shows that the resulting rate increases for production and transmission-related costs are 2.3% while page 3 of 3 in that Exhibit shows that the revenue increase for delivery-related costs is 12.1%. Further examination of Exhibit A-16, Schedule F3.0 shows that across all rate schedules production-related revenue is proposed to either decline or increase modestly, partly offset by uniformly small increases in transmission-related revenue. These trends illustrate that this case is primarily about the increasing costs of Consumers Energy's distribution system.[3]

Consumers Energy's testimony makes it clear that they are attempting to justify the increasing cost of their distribution system based claims about on improving reliability.[4]

Because Consumers Energy heavily allocates the costs of their distribution system to residential customers, and proposes in this case to further shift distribution system costs onto residential customers[5], Exhibit A-16 Schedule F2.0 page 1 of 3 shows that Consumers Energy is proposing to increase rates and revenue from residential customers by 8.8%,

[2] Direct testimony of Michael A. Torrey 5:23-6:1.
[3] Consumers Energy's proposals in their last rate case, U-20697, were similarly for a modest reduction in production and transmission revenues, a large increase in distribution revenues, and consequent very large 14% increase in residential rates with declines or modest increases for other classes.
[4] Direct testimony of Michael A. Torrey 8:5-9:16.
[5] Direct testimony of Emily A. Davis 16:1-4.

increase rates and revenue from primary customers by 4.2% and to decrease rates and revenues from secondary commercial customers by 0.1% and from lighting customers by 9.9% for a total bundled service revenue increase of 5.5%. Residential customers are proposed to pay $190.367 million more per year out of a proposed $225 million increase in total jurisdictional revenue, or approximately 85% of the revenue increase. Thus, a fundamental question in this case is whether residential rates should be substantially increased in order to improve distribution system reliability for all customers.

Consumers Energy presents estimates of the costs of distribution system power outages in Figure 9 of the testimony of Brenda L. Houtz,[6] which I reproduce here:

[6] Direct testimony of Brenda L. Houtz 14:1-3.

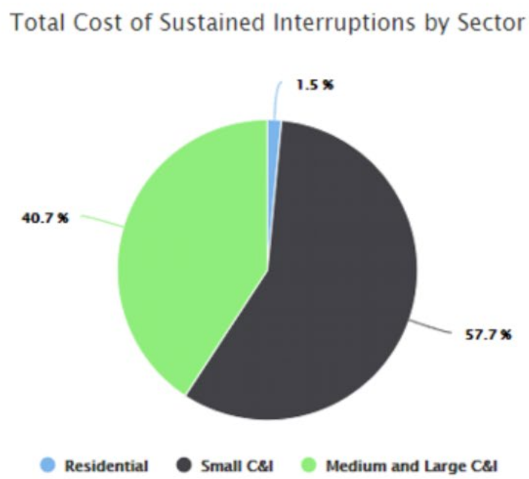
Stats Including MED, 2020 data

SAIFI	SAIDI	CAIDI
1.348	510.31	378.56

SAIFI	SAIDI	CAIDI	#Residential	#Non-Residential
1.348	510.31	378.56	1,631,811	221,082

Interruption Cost Estimates

Sector	# of Customers	Cost Per Event (2016$)	Cost Per Average kW (2016$)	Cost Per Unserved kWh (2016$)	Total Cost (2016$)
Residential	1,631,811	$12.24	$13.24	$2.10	$26,921,390.46
Small C&I	198,592	$3,866.91	$1,042.28	$165.20	$1,035,179,313.50
Medium and Large C&I	22,490	$24,094.71	$193.80	$30.72	$730,467,906.31
All Customers	**1,852,893**	**$717.69**	**$263.76**	**$41.80**	**$1,792,568,610.28**



As this figure illustrates, the costs estimated for sustained interruptions are very heavily weighted to commercial customers, with only a tiny fraction weighted to residential customers who are proposed to bear the vast majority of the distribution revenue increases. Thus, this case is primarily about whether Consumers Energy's residential rates should be substantially increased almost entirely to decrease interruption costs for other customer classes.

Q. Is there any further context for this case that you want to bring to the Commission's

attention?

A. Yes. My colleague Rob Ozar provides testimony showing that Consumers Energy has extraordinarily high distribution system investments per customer (which of course implies high rates) and represents to investors that this is good for investors and that the Company plans to substantially increase that investment.

Q. In light of Consumers Energy's requests in this case and their comparative performance, how should the Commission approach this case?

A. The Commission should support continuing the clean energy transition, look for economically efficient ways to improve reliability of the distribution system, and look for ways to significantly limit the growth of residential rates.

IV. CONSUMERS ENERGY'S PERFORMANCE AND RETURN ON EQUITY

Q. How is Consumers' performance relevant in this case?

A. Consumers' overall performance is relevant in judging whether its proposals are reasonable and prudent, and particular in drawing attention to those aspects of this case that should be most carefully scrutinized. Overall performance is also an appropriate consideration when the Commission authorizes a level of return on equity.

Q. How should the Commission assess Consumers' performance?

A. The most useful way to assess Consumers' performance is by comparison to other utilities in the United States, using available standardized measures of utility performance on aspects of performance that are most important to Consumers' customers and to the residents of Michigan. 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. The Commission should focus on Consumers' performance relative to other utilities with respect to reliability, affordability, and protection of the environment. Exhibit MEC-2 is a report published by the Citizens Utility Board of Michigan in 2020, which was prepared by me and my staff at 5 Lakes Energy and undertakes such comparisons based on 2018 data. We are currently beginning to prepare a similar report based largely on 2019 data (these delays between the year on which we report and publication date reflect lags in reporting of relevant data by the US Department of Energy's Energy Information Administration). My assessment based on preliminary review of the data is that the picture has not materially changed from 2018 to 2019. Exhibit MEC-3 is a set of graphs that I prepared that compare Consumers Energy's performance on reliability, affordability, and costs to that of all of the states.

Q. How should the Commission assess Consumers' reliability?

A. Electricity is one of the essentials of modern life, impacting both comfort and public safety, so reliability of electricity supply is an important attribute of utility performance. 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 distribution system. These may occur because storms break powerlines, animals touch pairs of power lines and cause a "short," because equipment fails, and many other proximate causes.

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 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.

I recommend that the Commission assess Consumers' reliability by comparing its performance to that of other utilities both nationally and within Michigan, and metrics should include, among others, SAIDI, SAIFI, and CAIDI. I have included graphs making this comparison in Exhibit MEC-3. As can be seen in those graphs:

- Consumers' SAIDI including MED in 2018 was slightly better than the weighted average of Michigan utilities but, like the average of Michigan utilities, was worse than the performance of all but 12 other states.

- Consumers' SAIDI excluding MED in 2018 was worse than the weighted average of Michigan utilities and was worse than the performance of all but 6 states, while Michigan's average was worse than the performance of all but 8 states.

- Consumers' SAIFI including MED in 2018 was somewhat better that the weighted average of Michigan utilities and was near median of the country with 26 states having worse performance, while 24 states were worse than Michigan's average.

- Consumers' SAIFI excluding MED in 2018 was also slightly better than the weighted average of Michigan utilities and was near median of the country with 26 states having worse performance, while 25 states were worse than Michigan's average.

- Consumers' CAIDI including MED in 2018 was slightly better than the weighted average of Michigan utilities, and like Michigan was worse than the performance of all but 7 states.

- Consumers' CAIDI excluding MED in 2018 was distinctly worse than the weighted average of Michigan utilities, and like Michigan was worse than the performance of all states except West Virginia.

In short, Consumers' outage frequency is near median but its power restoration performance is quite poor.

Q. How should the Commission assess Consumers' 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 Electric Data Browser on its web site, at http://www.eia.gov/electricity/data/browser/. The most recent complete calendar year available is 2018 and it is used here for comparison of 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.

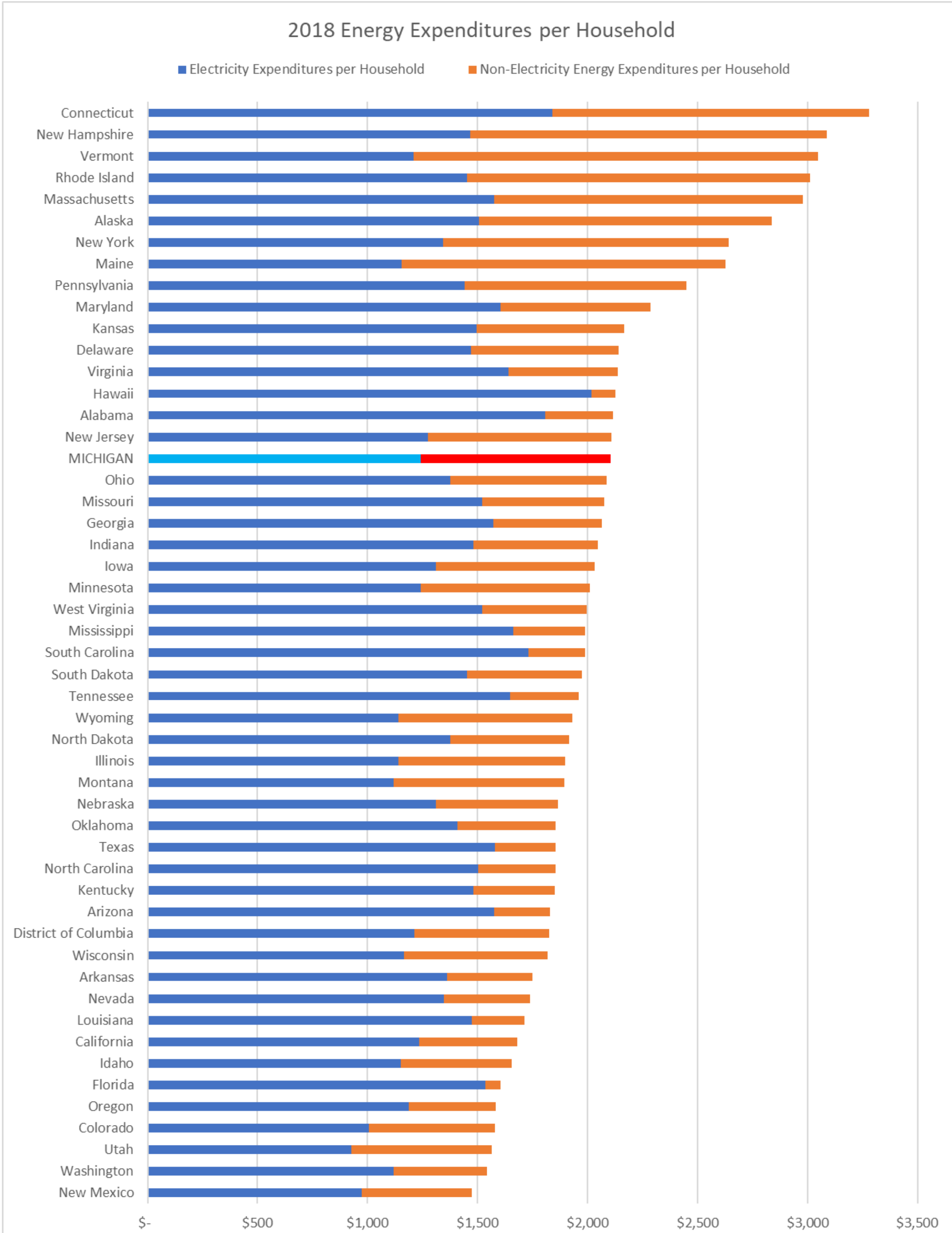
The affordability of electricity is a nuanced matter. For households in different regions of the country, the local climate and the availability of alternative heating fuels can affect the amount of electricity they consume. Expenditures on electricity and other heating fuels must be considered in context 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; rates comparison is more useful.

I recommend that the Commission assess Consumers' affordability by comparing its costs per unit of electricity by customer class both nationally and to other utilities in Michigan and also by considering total household energy bills in both absolute cost and in relation to income. Household energy bills include heating fuels. Consumers' electric customers use a variety of heating fuels and often obtain their heating fuel from other utilities or direct fuel providers (Consumers' 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, and then consider Consumers' electric rates in relation to other Michigan electric utilities. 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:

- Consumers' average industrial electricity rate in 2018 was slightly higher than the weighted average of industrial rates for Michigan utilities, though because of the relatively low variation in industrial rates across much of the United States this caused Consumers to have rates lower than only 13 states, while Michigan's average was lower than that of 24 states, putting Michigan near the national median.
- Consumers' average commercial rate in 2018 was noticeably higher than the weighted average of Michigan utilities, and was higher than all but 9 states, while Michigan's average was higher than all but 13 states.
- Consumers' average residential rate in 2018 was slightly above the weighted average of Michigan utilities, and both were higher than all but 10 states.
- Michigan's average household energy (electricity plus heating fuel) bill in 2018 was higher than all but 16 states, and since Consumers' average residential rate is near though slightly higher than the Michigan average, Michigan's ranking likely represents Consumers' relative position as well.
- Michigan's average household electricity plus heating bill as a percentage of household income in 2018 was higher than all but 14 states.

In short, Consumers' 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 neighboring state. Only Alaska and the mostly high-income northeastern states have significantly higher household energy bills than Michigan residents.

Q. How should the Commission assess Consumers' environmental performance?

A. There are a number of 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:[7]

- 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

[7] 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.

- 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 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. [8] 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 Consumers' 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.

[8] 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.

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 Consumers' comparative performance amongst Michigan utilities based on the Commission's knowledge of Consumers' power supply arrangements. I have included graphs of Michigan's emissions intensity in Exhibit MEC-3. As can be seen in those graphs,

- Michigan's average carbon dioxide intensity of electric generation in 2018 was somewhat worse than the national median, with 19 states having greater carbon dioxide intensity of electric generation;

- Michigan's average sulfur dioxide intensity of electric generation in 2018 was considerably worse than the national median, with only 9 states having greater sulfur dioxide intensity of electric generation;

- Michigan's average nitrogen oxide intensity of electric generation in 2018 was somewhat worse than the national median, with 17 states having greater nitrogen oxide intensity of electric generation.

Michigan's generation mix did not change substantially between 2018 and 2019, so these emissions intensities likely did not change materially.

Consumers' recent historical performance on these metrics is likely somewhat better than statewide average due to the 2016 retirement and replacement of several coal plants, and the trajectory established in Consumers' 2018 integrated resource plan shows continuing improvement in its environmental performance.[9]

Q. Please summarize Consumers' overall performance.

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

Consumers' 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 frequency of outages as measured by SAIFI.

Consumers' rates were in the worst quartile but rank noticeably worse for residential and commercial customers than for industrial customers. Affordability of household energy was also materially worse than the national median reflecting a combination of comparatively high rates and comparatively low income.

Michigan's emissions intensity of electric generation was worse than average, but especially poor for sulfur dioxides. Consumers' recent performance on these metrics is likely better than the Michigan average, due to its earlier retirement of coal plants.

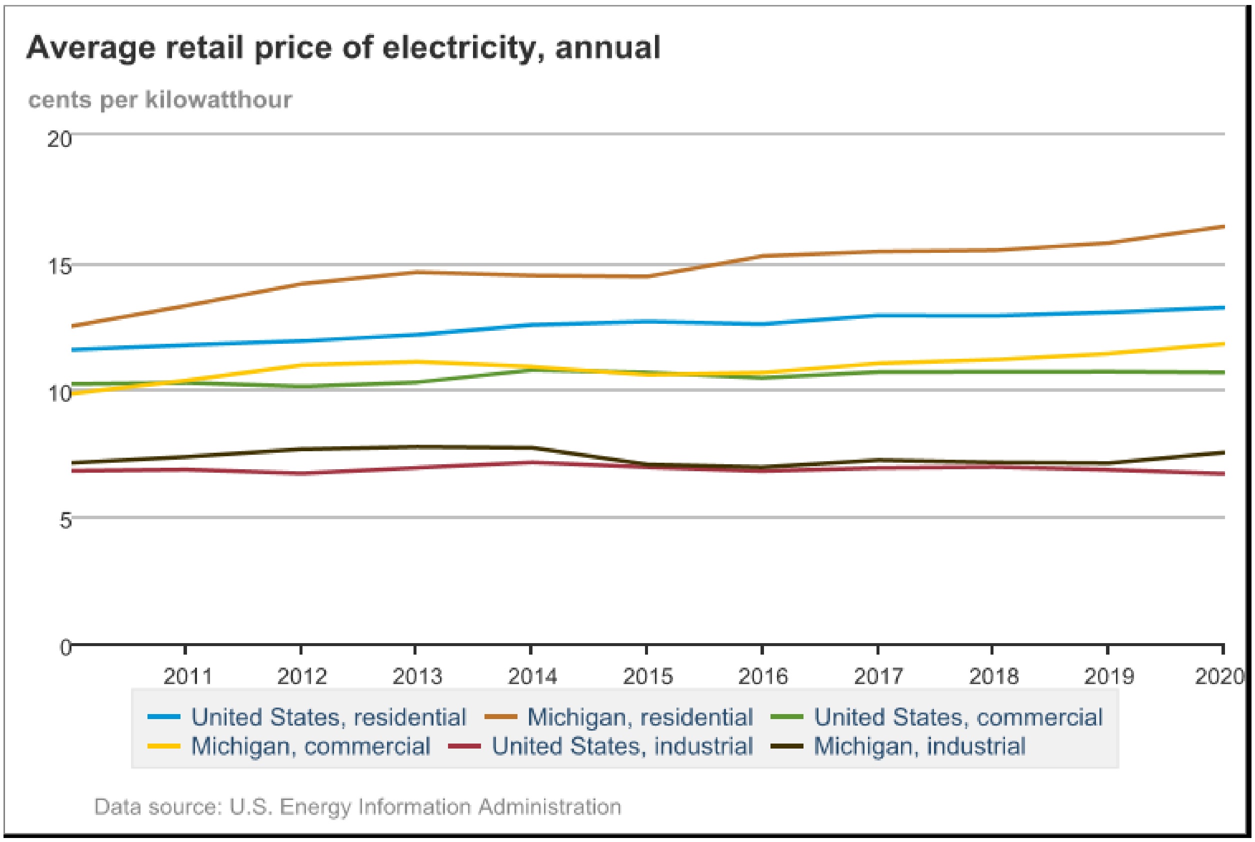
Q. Understanding that you have not yet compiled the national data for 2019, how did

[9] 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.

Consumers Energy perform more recently than 2018?

A. Consumers Energy witness Richard T. Blumenstock presents graphs showing Consumers Energy's reliability performance using the SAIDI, SIAFI, and CAIDI metrics through 2020.[10] These figures do not show material improvement since 2018.

To compare rates, I obtained the following chart from the US Department of Energy's Energy Information Administration web site:[11]



Although this graph is not specific to Consumers Energy, it does illustrate that while Michigan's industrial and commercial rates have generally remained close to national

[10] Direct testimony of Richard T. Blumenstock, Figures 11 through 14, pp 32-34.
[11] https://www.eia.gov/electricity/data/browser/

average, our residential rates have been higher than the national average and have been steadily increasing at rates higher than the national average.

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

A. I recommend that the Commission deny Consumers Energy's request for an increase in authorized return on equity from 10% to 10.5% and say in doing so that this is in part based on the Company's performance. I also recommend that the Commission consider reducing the authorized return on equity to 9.5% on that same basis.

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

A. Yes. It is well established that regulated utilities that create firm value by earning returns on their investments are incented to inefficiently invest capital, especially if the authorized return on equity is high.[12] A reduction in return on equity could reduce Consumers Energy's incentive to be economically inefficient in its expenditures on its distribution system.

IV. TEST YEAR PROJECTIONS

Q. Did you evaluate Consumers Energy's test year cost projections?

A. Yes. My colleagues will address specific programs and changes and I evaluated Consumers Energy's general forecasts. Consumers Energy used calendar 2019 as the historical test year and calendar 2022 as the projected test year in this case, so that the forecasts are based

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

on a mixture of records and projections for 2020 and projections for 2021 and 2022. As summarized by Consumers Energy witness Jason R. Coker, the Company used "inflation factors of 1.20% for 2020, 2.50% for 2021, and 2.30% for 2022, as forecasted by IHS Global Insight and reported in the September 2020 edition of its publication *U.S. Economic Outlook*."[13]

In addition, the Company applied a different rate to internal labor costs. As described by Consumers Energy witness Amy M. Conrad,

> The assumed rate of labor used to project O&M labor expense is 3.2%, which applies a projected salary increase of the same percent. The increase of 3.2% is consistent with the company['s] planned merit budget. The labor rate is derived from independent third-party survey sources. See Confidential Exhibits A-72-75 (AMC-4-AMC-7) for survey data from PayFactor, World at World, Mercer, and Willis Towers Watson.[14]

Exhibits illustrate that this 3.2% increase was applied on a compounding basis from 2019 to 2020, 2020 to 2021, and 2021 to 2022.[15]

Q. Do you have any concerns about the ways in which Consumers Energy developed its projected test year costs?

A. Yes, I have three principal concerns:

- Consumers Energy appears to have used the Consumer Price Index as the inflation factor for the goods and services it purchases[16], which is not the appropriate price index for that purpose.

[13] Direct testimony of Jason R. Coker 13:5-8.
[14] Direct testimony of Amy M. Conrad 39:20-22.
[15] See, for example, Exhibit A-71, page 3 of 3.
[16] The inflation factors used by Consumers Energy in this case correspond to the Consumer Prices changes included in Jason R. Coker's workpaper WP-JRC-59.

- Consumers Energy incorrectly uses merit increases as the basis for labor cost inflation.
- Consumers Energy has not accounted for any gains in productivity when projecting its costs.

Q. Please explain your concern about the use of the Consumers Price Index as an inflation factor for Consumers Energy's purchases.

A. As explained by the US Bureau of Labor Statistics, which compiles and publishes the Consumers Price Index, "The Consumer Price Index (CPI) is a measure of the average change over time in the prices paid by urban consumers for a market basket of consumer goods and services." The market basket of goods included in the CPI is not representative of the goods and services purchased by Consumers Energy.

A more appropriate index of costs for Consumers Energy is the US Bureau of Economic Analysis ("BEA") Chain-Type Price Indexes for Intermediate Inputs by Industry, which is described as "This table presents a chain-type price index for the intermediate inputs of an industry. The price index for each industry represents the prices paid for the energy, raw materials, semi-finished goods, and services used by the industry to produce gross output. These price indexes are prepared by combining the price indexes for the commodities that the industries consume in a Fisher index-number formula."[17] I obtained this index for the Utilities sector (and for comparison purposes the entire Private Industries sector) from the BEA Interactive Data Application[18], which is shown in the following table:

[17] https://www.bea.gov/resources/guide-interactive-gdp-industry-accounts-tables
[18] https://apps.bea.gov/iTable/index_industry_gdpIndy.cfm

Bureau of Economic Analysis
Chain-Type Price Indexes for Intermediate Inputs by Industry
[2012=100]
Last Revised on: March 25, 2021

Line		2015	2016	2017	2018	2019	2020
Line							
2	**Private industries**	**98.995**	**98.252**	**101.357**	**105.448**	**106.636**	**106.017**
10	**Utilities**	**96.010**	**94.873**	**102.298**	**108.105**	**106.241**	**102.211**

As can be seen, the cost of intermediate goods and services approximately reflecting the market basket of purchases by Consumers Energy does not show the same trends as the Consumer Price Index. Prices in 2020 were approximately the same as in 2017. There was an increase from to 2017 to 2018, which receded somewhat in 2019 before the onset of the COVID-19 pandemic and further declined in 2020. In my opinion, it is likely that these costs will rebound somewhat in later 2021 to 2022 as the temporary economic effects of the COVID-19 pandemic recede, but that this is unlikely to amount to the cumulative 6.1% increase from 2019 to 2020 that is assumed by Consumers Energy in its projections, as that would be an increase in the Chain-Type Price Index for Intermediate Inputs for Utilities to about 114.716, or an increase of 12.2% from 2020 to 2022.

I recommend that the Commission remove Consumers' inflation adjustments for purchased goods and services from both operations and maintenance expenses and capital investment for the projections from 2019 to 2020 and from 2020 to 2021. As an inflation factor from 2021 to 2022, it would be appropriate to use the GDP Deflator from the same report on which the Company relied for its consumer price change forecast, which has the value 1.6 since the GDP Deflator is the broadest generally available measure of price inflation in the economy. My recommendation will result in a compound increase in projected costs of purchased goods and services of 1.6% as opposed to the 6.12% compound inflation adjustment proposed by the Company. I therefore recommend reducing all Consumers Energy purchased goods and services cost projections, including both operations and maintenance and capitalized items by 4.26%.[19] An alternative way to make this calculation is to reduce total inflationary increases for goods and services by 70% (computed as 4.26% divided by 6.12%)

Alternatively, the Company could obtain and apply separate indices of the costs of intermediate (business) services and finished goods.

Q. Please explain your concern that Consumers Energy has incorrectly applied merit increases as the basis for labor cost inflation.

A. Consumers Energy has made a conceptual error in using merit increases as the basis for labor cost inflation. In order to establish what Consumers Energy means by "merit increases", we asked for further information in discovery.[20] It is apparent that the 3.2% merit increase used by the Company to project labor costs is an average annual increase for an employee in a continuing role. It does not account for promotions nor for departures and replacements with new employees in a given role. To illustrate why this is an error, consider a simple hypothetical department with five employees in a role, who happen to have been hired one per year from 2016-20 at the same starting annual salary of $40,000

[19] This number is computed as 1.0612 minus 1.016, divided by 1.0612 to reflect the algebra of how these multipliers are applied in cost projections
[20] Exhibit MEC-4 (DJ-4) Consumers Energy response to MEC-CE-373 and the Part III Attachment 73 from the Company's initial filing that is referenced therein.

and who each receive an annual 3.2% merit increase. Further suppose that in the transition from 2020 to 2021, the most senior employee is promoted out of the department or otherwise departs and is replaced by a new hire at $40,000. The following table illustrates the payroll for this department:

Employee	2020 Salary	2021 Salary
1	$40,000.00	$41,280.00
2	$41,280.00	$42,600.96
3	$42,600.96	$43,964.19
4	$43,964.19	$45,371.04
5	$45,371.04	Departed
6	Not hired yet	$40,000
Department Total	$213,216.19	$213,216.19

While this table represents a highly simplified case, it illustrates that merit increases are not the same as labor cost increases. To determine labor cost increases based on changes in individual compensation, it would be necessary to model workforce turnover and the costs of new hires as well. In fact, with a bit of mathematics it becomes clear that with constant rates of increase in starting salaries and turnover rates, it is the rate of change in starting salaries that drives labor costs.

Q. How do you recommend that the Commission respond to Consumers Energy's proposal to use merit increases to determine labor cost increases?

A. I recommend that the Commission reject this approach and require Consumers to use an index of labor market conditions or demonstrate extraordinary circumstances in their labor costs. For example, the same IHS Markit report[21] that Consumers Energy used to obtain consumer price change forecasts also has an employment cost index, which shows increases of 2.4% from 2019 to 2020, 2.2% from 2020 to 2021, and 3.3% from 2021 to 2022. I recommend that the Commission adopt these labor cost inflators for purposes of this case but advise Consumers Energy that in future cases, the Company must demonstrate the applicability of any index they propose to use based on both its conceptual definition and comparison to trends in Consumers Energy's actual employment costs. The compound labor cost increase from 2019 to 2022 using the IHS employment cost index is 8.1%, as contrasted to the compound increase of 9.9% using Consumers Energy's merit increases at 3.2% per year. I therefore recommend reducing all Consumers Energy labor cost projections, including both operations and maintenance and capitalized labor by 1.64% (computed as 1.099 minus 1.081, divided by 1.099 to reflect the algebra of how these multipliers are applied in cost projections). An alternative way to make this calculation is to reduce labor cost increases by 16.6% (computed as 1.64% divided by 9.9%).

Q. How can the Commission apply the reductions in cost projections you recommend above?

A. Consumers Energy's general cost projection factors for labor and purchased goods and services are embedded in the details of its various cost projections, line item by line item. However, these inflationary and merit increases for Other Operations and Maintenance are summarized in Exhibit A-13 (JRC-42) Schedule C-5a. I traced each row of that exhibit that

[21] See Jason R. Coker's work paper WP-JRC-59.

included inflation increases as shown in columns (d), (e), and (f) and calculated the following corrections based on the percentage reductions to labor and goods and services increases that I described above:

A-13 Schedule C-5a Line	Description	Source	CE Proposed Labor Increases	CE Proposed Goods and Services Increases	CE Total Projected Adjustments	MNSC Labor Correction	MNSC G&S Correction	MNSC Total Correction	MNSC Corrected Total Adjustments
1	Electric Division - Electric & Common	Exhibit A-47 (RTB-14)	5,076	3,182	11,027	(843)	(2,227)	(3,070)	7,957
2	Forestry	Exhibit A-58 (PLB-6)	870	1,020	41,065	(144)	(714)	(858)	40,207
3	Generation	Exhbit A-95 (SAH-5)	7,067	2,616	23,647	(1,173)	(1,831)	(3,004)	20,643
4	Operations Support	Exhibit A-18 (SJB-2)	669	(435)	234	(111)	305	193	427
5	Information Technology Operations	Exhibit A-104 (JDT-2)	1,203	5,413	3,412	(200)	(3,789)	(3,989)	(577)
7	Customer Interactions	Exhibit A-87 (AJG-2)	3,634	23,636	4,862	(603)	(16,545)	(17,148)	(12,286)
8	Billing and Payment	Exhibit A-87 (AJG-2)	(116)	5,083	4,967	19	(3,558)	(3,539)	1,428
9	Demand Response	Exhibit A-87 (AJG-2)	1,671	3,192	26,580	(277)	(2,234)	(2,512)	24,068
16	Corporate Services	Exhibit A-83 (KMG-2)	3,221	1,327	11,611	(535)	(929)	(1,464)	10,147
	TOTAL		23,295	45,034	127,405	(3,867)	(31,524)	(35,391)	92,014

Q. Please explain your concern that Consumers Energy has not accounted for any gains in productivity when projecting its costs.

A. Consumers Energy has projected costs for 2022 by applying inflation factors to the prices of both labor and purchased goods and services and adding projected costs for various program changes and projects. In doing so, they have not projected any improvements in productivity, either labor productivity or multifactor productivity. When rates are based on historical data, we rely on accounting records of actual costs. When rates are based on a projected test year, it is necessary to both account for reasonable expectations of costs and to ensure that the utility is incented to be cost-efficient. For both reasons, the Commission should base revenue requirements and therefore rates on reasonable expectations of continuing improvement in Company productivity.

In the testimony of Michael A. Torrey, Consumers Energy provides discussion of CE Way, which Mr. Torrey characterizes as “the Company’s operating system based on lean business principles."[22] Through discovery, we sought to determine whether the Company has expectations of productivity improvement through that program.[23] In that response, Consumers Energy reports that it "has a waste elimination goal to identify $35 million of O&M savings in 2021 collectively for electric and gas operations" and that it is "focused on 5% year-over-year O&M savings."

No productivity improvements are apparent in Consumers Energy's projected test year costs. Indeed, in Exhibit MEC-5, the Company responds that "As we deploy the CE Way across the enterprise, savings can be redeployed into the business and ultimately help us to achieve more work at similar costs for customers. It also allows us to address underfunded areas that require such a reinvestment." However, Consumers Energy proposes many and large increases in both rate base and operations and maintenance costs in this case and does not show an offset for expected productivity improvements.

In order to both encourage the Company to concentrate on productivity gains and reductions in distribution system costs, I recommend that the Commission reduce Consumers Energy's projected revenue requirements for distribution O&M by $10 million.[24] I further recommend that the Commission require Consumers Energy to include and support the value of an explicit productivity improvement factor (or multiple factors for different portions of the business) in test year cost projections in future rate cases. As an aid to the Commission and the Company, I note that the US Bureau of Labor Statistics tracks multi-factor productivity in the US economy. From 2007-2019, multifactor

[22] Direct testimony of Michael A. Torrey 7:3-4.
[23] Exhibit MEC-5 (DJ-5) consists of Consumers Energy's response to MEC-CE-406.
[24] This should be taken from Line 1 of Exhibit A-13 (JRC-41) Schedule C-5.

productivity gains contributed 0.33% annually to output growth in private businesses.[25] Thus, absent evidence more specific to electric utilities, a reasonable first estimate of the level of productivity improvement that can be expected of Consumers Energy going forward is 0.33% per year. If applied to the 2022 projected test year based on a 2019 historical test year, this rate of productivity improvement would have been expected to reduce Consumers Energy's costs by about 1%; thus, as an alternative the Commission could choose to reduce Consumers Energy's test year cost projections by 1% in addition to the corrections of inflation rates and labor cost adjustments that I recommended above instead of removing $10 million from distribution system operations and maintenance.[26]

V. COST-OF-SERVICE ALLOCATION

Q. In this case Consumers Energy proposes to use a cost-of-service allocation study that differs from the one approved in the last case. Please explain the difference.

A. Consumers Energy presents their class cost-of-service study in this case primarily through the testimony of Emily A. Davis.

The cost-of-service study in the last case, which is updated and presented in this case as version 1 of their cost-of-service study, allocated most distribution system costs either directly or indirectly based on the class peak of the classes used in the cost-of-service study.[27] In that method, the demand by each class in the hour of the year when that class has its annual peak usage is referred to as the class peak. Different classes generally peak

[25] https://www.bls.gov/mfp/contributions-to-output.htm
[26] $10 million should be deducted from Exhibit A-13 Schedule C-5a, Line 1.
[27] Certain modifications of COSS version 1 from the last case to this one are described by Emily A. Davis, 8:2-10:15.

in different hours. The class peak method allocates costs to each class in proportion to the ratio of that class's peak to the sum of the class peaks for all classes. The costs associated with different voltage levels of the distribution system are allocated by the class peak method to the classes served at that voltage level or below.

In this case, Consumers Energy proposes to adopt version 2 of their class cost-of-service study, which allocates costs of each voltage level in their distribution system in proportion to the class's contribution to the peak usage of that voltage level over the course of the year.[28] This differs from the class peak method in that cost shares at each voltage level are based on class shares of demand at the same coincident time.

Q. What is Consumers Energy's rationale for this change?

A. Consumers Energy asserts two reasons:

> First, the Voltage Peak allocator measures the contribution of each rate class to the coincident peak demand at each level of the distribution system, which aligns with how engineering sizes its facilities today. Second, the Voltage Peak results are unaffected by how rates are grouped together because it measures coincident peak demand.[29]

Consumers Energy witness Davis also asserts that

> The Company's proposal to replace the Class Peak allocator at each voltage with a new Voltage Peak allocator is also responsive to criticism of the Class Peak allocator that some parties provided in Case No. U-20697.[30]

I believe that statement refers to my testimony in Case No. U-20697 in which I made essentially these arguments against the use of the class peak method.

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[28] Direct testimony of Emily A. Davis, 2:20-3:4 and 12:9-15:15.
[29] Direct testimony of Emily A. Davis 15:6-9.
[30] Direct testimony of Emily A. Davis 14:17-19.

Q. What effect does this change have on the allocation of distribution system costs?

A. Witness Davis summarizes the effect as

> the Company's Voltage Peak proposal (included in COSS Version 2) would increase residential costs 2.0% over present revenue and decrease secondary commercial, primary, and lighting costs by 3.0%, 1.1%, and 11.9%, respectively compared to Version 1 of the COSS.[31]

Q. Is a reallocation of distribution costs to residential customers an appropriate result of revising the cost-of-service study?

A. The cost-of-service study should reflect cost causation, so whether or not a reallocation is appropriate cannot be determined except by an analysis of the methodology. However, there are two important clues that this may be an inappropriate result.

First, as I showed earlier, Consumers Energy has exceptionally high residential rates and near-median commercial and industrial rates compared to the rest of the country. This suggests that cost allocation as done by Consumers Energy is producing abnormal results.

Second, in the voltage peak method proposed by Consumers Energy in this case, residential customers will pay 48.9% of Voltage 1 costs, 53.44% of Voltage 2 costs, 57.46% of Voltage 3 costs, and 73.55% of Voltage 4 costs.[32] Consumers Energy has in recent years substantially increased expenditures on the distribution system and is proposing in this case further substantial increases in distribution spending, justified primarily by the need to improve reliability. However, the Company estimates that only 1.5% of the benefits of improved reliability accrue to residential customers.[33] Indeed, by that analysis, the annual

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[31] Direct testimony of Emily A. Davis, 16:1-4.
[32] Excel workpapers for Exhibit A-16 (EAD-2) Sch 1.1, Voltage Peak tab, cells BB49:BB52.
[33] Direct testimony of Brenda L. Houtz, Figure 9, 14:3.

cost of all outages for residential customers in 2016 was about $27 million while in this case alone the Company proposes to spend almost $380 million in 2022 on reliability improvements[34] and more than $95 million on line clearing forestry.[35] The residential class share of this spending that is justified based on reliability improvements will be approximately 10 times Consumers Energy's own estimate of the annual cost of outages to residential customers. Since these expenditures will not eliminate but will only modestly improve residential customer outage experience, the cost of these reliability program expenditures and line clearing to residential customers is on the order of 50 times the benefit to residential customers. The Commission must either severely reduce these expenditures or seriously recalibrate cost allocation for the distribution system.

Q. Do you support Consumers Energy's proposal to change from the class peak method to the voltage peak method for allocating distribution system costs?

A. No. I support moving away from class peak and to a method that reflects engineering practice, but this proposal is flawed and has the effect of "cherry-picking" my previous recommendations to the detriment of residential customers. I recommend that the Commission reject version 2 in this case and direct Consumers Energy to revise this proposal in specific ways in its next rate case.

Q. In what way is the Consumers Energy voltage peak method flawed?

A. The Company is correct to seek to allocate costs using methods that reflect planning and engineering practice, as that is the right basis for determining cost causation. However, the

[34] Exhibit A-36 and Exhibit A-46.
[35] Direct testimony of Pamela L. Bolden, Figure 3, 6:13.

use of class contributions to demand in a single peak hour at each voltage level does not reflect Consumers Energy's engineering practices, nor the practices recommended in standard distribution system engineering texts.

Q. Why does the use of class contributions to demand in a single peak hour at each voltage level not reflect engineering practices?

A. There are several ways that it does not reflect engineering practice. The first is that peak demand on each distribution system component is likely not coincident with the single hour of the overall system peak.

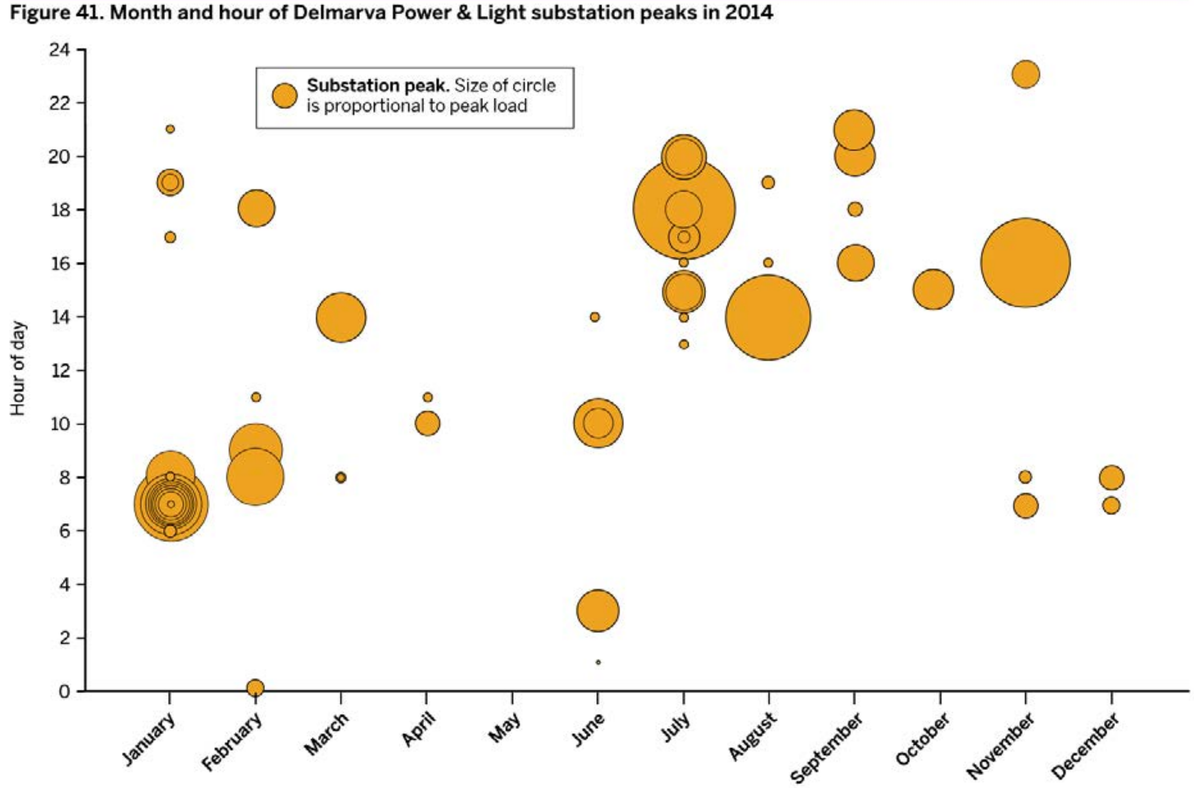
Consumers Energy's rationale is based on the premise that current engineering practice is to size the system based on coincident peaks at the various voltage levels of the system.[36] That is simply not the case. Each component of the system is or should be sized based on a coincident demand on that component and all components at a given voltage level are not sized based on the same coincident peak time.

Consumers Energy has approximately 180 substations that include high-voltage distribution system components.[37] These substations have differing mixtures of customer classes and experience somewhat varying weather conditions and economic conditions. It is a virtual certainty that all of these substations do not experience their annual peak load in the same hour of the year, yet that is the claim on which the voltage peak method is based.

[36] Direct testimony of Emily A. Davis, 15:8 and footnote 6.
[37] Direct testimony of Richard T. Blumenstock 11:2-3.

Consumers Energy has approximately 1100 low-voltage distribution system substations.[38] 783 of these are general distribution substations, 265 are dedicated to specific customers, and 35 provide wholesale distribution to co-op and municipal utilities. The dedicated substations almost certainly have different patterns of usage than the total load on the low-voltage distribution system and even the general distribution substations no doubt have varying load profiles depending on whether they serve rural areas, downtown business districts, suburban housing areas, etc. The following graph[39] 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

[38] Direct testimony of Richard T. Blumenstock 11:15-20.
[39] Obtained from Lazar, J, P Chernick, and W. Marcus. 2020 Electric Cost Allocation for a New Era: A Manual. Regulatory Assistance Project, provided as Exhibit MEC-9 (DJ-9).

Consumers Energy also has more than 2000 low-voltage distribution circuits[40] emanating from those 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.

Consumers Energy has approximately 650,000 line transformers in its distribution system, to serve primary and secondary customers.[41] Those line transformers serve one to a few customers, with different customers having different operating hours, weather-sensitivity of heating and cooling requirements, and simply random differences in load profiles. It would be absurd to think that all of these line transformers experience peak loads at the same time.

For this reason, cost allocation based on engineering practice would need to be based on an examination of how much capacity at each voltage level has its peak usage at different times and the contributions of the various classes to those coincident peaks on each unit of capacity.

Q. Is there another reason that the use of class contributions to demand in a single peak hour at each voltage level not reflect engineering practices?

A. Yes, the sizing of any distribution system component is generally not based on demand in a single hour. Transformer sizing is based on load over a number of consecutive hours and the frequency of high loads over the year. In response to discovery Consumers Energy

[40] Direct testimony of Richard T. Blumenstock 9:18-19.
[41] Consumers Energy's MPSC Form P-521 for the end of 2019, page 429.

witness Richard T. Blumenstock confirms that Consumers Energy bases transformer sizes on Annex G of IEEE/ANSI Standard C57.91-1995 and does so using software, the manual for which was also provided in response to discovery.[42] Pages 8-10 of the software manual describe the algorithm used to size a single transformer and clearly show that it is based on loss of life calculations related to thermal loading across a season and is based on both ambient temperatures and electrical loads.

Transformer capacity is rated based on the transformer's ability to sustain a constant load at the rated flow over an extended period of time at the relatively high ambient temperature of 30 degrees Celsius.[43] When demand on a transformer exceeds that rating, the transformer does not reject the excess demand; up to very high relative demand the transformer serves the demanded current but experiences heating and potential loss of life. When load preceding that high load was less than the rated capacity, the transformer will be cooler and can sustain a period of load above rated capacity without overheating and experiencing loss of life. Annex G of IEEE/ANSI Standard C57.91 describes in detail the appropriate calculations to account for varying loads on a transformer and varying ambient temperature.[44] It implements guidance contained in IEEE/ANSI Standard C57.91. In Section 7.1.4 of the Standard, it is further recommended that this can be simplified to Equation (6)

[42] Exhibit MEC-6 (DJ-6) consisting of Consumers Energy response to discovery request MEC-CE-489, including Attachment 1.
[43] Short, T. A. 2014. Electric Power Distribution Handbook, 2nd Edition. Electric Power Research Institute. CRC Press, Chapter 5.
[44] Exhibit MEC-7 (DJ-7) is a redline copy of IEEE/ANSI Standard C57.91-1995 published by IEEE to show the changes made in the 2011 edition.

$$\text{Equivalent continuous 12 h prior load} = 0.29\left[L_1^2 + L_2^2 + \ldots\ldots + L_{12}^2\right]^{0.5} \qquad (6)$$

where the L_i are the hourly loads for the prior 12 hours. Formulae like this one are referred to as "root mean square". Had we obtained detailed substation data from Consumers Energy through discovery, this is the formula that I would have applied to determine the timing and capacity requirements share of substations. The point to be observed here is that the sizing of a transformer is not based on load in a single hour but over an extended period of time, typically analyzed over 12- or 24-hour periods.[45]

An industrial or commercial load that runs fairly consistently at a given level over many hours will require significantly higher transformer capacity relative to its peak load than a residential load that is highly variable and has short spikes in load lasting only minutes to a couple of hours. It is thus highly inaccurate to attribute transformer costs to all loads based on their contributions to a single peak hour. On the other hand, for a given average load a variable load will have higher root mean square than a consistent load. Thus, consideration of root mean square criteria will attribute a higher share of costs to variable loads than simple average energy. For transformers and related costs, an adequate cost allocator metric will almost certainly be based on root mean square loads informed by the distribution of component root mean square load peaks across hours of the year.

[45] This is the practice also propounded in Short, T. A. 2014. Electric Power Distribution Handbook, 2nd Edition. Electric Power Research Institute. CRC Press, Chapter 5 and in Layton, Lee. 2016 Electric Power Distribution Transformers and in Willis, H. Lee. 2004. Power Distribution Planning Reference Book, 2nd Edition. Marcel Dekker Section 11.3 and in Kersting, William H. 2012. Distribution System Modeling and Analysis, 3rd Edition. CRC Press.

Engineering best practices for the selection of conductor ampacity (hence wire circumference) are similarly based in significant part on root mean square loads. Unlike transformer sizing which is based on avoiding thermal damage to the transformer over a relatively short run of several hours, the economic sizing of conductors is normally based on the economic tradeoff between line losses and conductor costs over the entire annual load cycle. As a result, conductor sizing and cost is essentially linear in annual root mean square load on the conductor.[46] However, some line equipment such as voltage regulation is needed to manage voltage drop and high load times. For distribution lines, an allocator will almost certainly be based on root mean square loads informed by the variability of such metrics amongst circuits.

Q. Are there additional reasons that costs are not caused by the demand in a single hour?

A. Yes, even if required capacity in the distribution system was caused by demand in a single hour, that does not mean that all costs should be attributed to that hour. If demand in that peak hour was eliminated altogether, much of the capacity would still be required in the next highest hour, etc. Thus, the entirety of capacity needed for a peak demand cannot be properly viewed as caused by that peak demand. Only the increment above the demand at some other time is caused by the peak demand. It is therefore unreasonable to allocate all costs of capacity to the peak. Rather, costs should be assigned to power delivered at all hours, with a higher allocation of costs at times when capacity is approached. Notably, that

[46] See Kersting, William H. 2012. Distribution System Modeling and Analysis, 3rd Edition. CRC Press, Chapter 10, Willis, H. Lee. 2004. Power Distribution Planning Reference Book, 2nd Edition. Marcel Dekker Section 11.2, Gonen, Turan. 2014. Electric Power Distribution Engineering, 3rd Edition. CRC Press, Chapters 5 and 6, in Short, T. A. 2014. Electric Power Distribution Handbook, 2nd Edition. Electric Power Research Institute. CRC Press, Chapter 2.

is the result obtained by using root mean square of loads, suggesting that a method based on root mean square calculations will produce reasonable results.

Q. Have you attempted to calculate the appropriate allocation of costs based on the diversity of timing of peak loads and extended load periods, as you described above?

A. In this case, I intended to perform such calculations for substations, those being the least numerous and individually somewhat costly components of the distribution system. Exhibit MEC-7 (DJ-7) is Consumers Energy's response to the discovery requests made to obtain those data.[47] While Consumers Energy provided certain capacity information for its substations, it did not provide the essential 8760 load profiles for those substations or the composition of that load by customer class. Follow-up rephrasing of those discovery requests would not have left sufficient time for data analysis in the context of this case schedule.

Q. Doesn't Consumers Energy witness Davis also suggest that the Voltage Peak method may not be appropriate?

A. Yes. Witness Davis's testimony is that:

> While the Company's Voltage Peak proposal resolves issues with the current allocation of demand-related costs it does not resolve the issue regarding the appropriate classification of costs within COSS. The Company continues to believe a minimum size, zero intercept or similar study would be appropriate. While the Commission has rejected such studies in the past, and the Company is not making such a proposal in this case, the Company continues to explore this concept and may make such a proposal in the future.

[47] Exhibit MEC-8 (DJ-8) consists of Consumers Energy responses to discovery requests MEC-CE-486 and MEC-CE-488.

Q. What is your evaluation of these comments by Ms. Davis?

A. I agree with her that the Voltage Peak resolves some issues with the current allocation of demand-related costs and that it does not resolve the issue regarding the appropriate classification of costs within the COSS. However, this comment also illustrates that Consumers Energy has not yet come to grips with the defects of the minimum size and zero intercept methods. Even if the minimum system or zero-intercept methods correctly classifies costs as demand and non-demand, it does not follow that the non-demand costs are customer costs. The primary purpose of the distribution system is to delivery energy, so the appropriate basis for allocating costs not associated with high demand is on the basis of energy. Rather than elaborate this argument at length, I recommend a review of Chapter 11 of Exhibit MEC-9.[48]

Q. What do you recommend to the Commission with respect to the cost-of-service study?

A. I recommend that the Commission decline to accept the voltage peak method and version 2 of the cost-of-service study as proposed by Consumers Energy in this case. Instead, the Commission should endorse the idea of moving away from the class peak method when an acceptable alternative is proposed. The Commission should direct Consumers Energy to include in its next rate case at least one cost-of-service study that incorporates the diversity of peak hours on various sections of the distribution system (such as substations) and the use of the metrics used in actual engineering practices (such as the use of root mean square load) as measures of demand. The Commission should remind Consumers Energy of the Commission's ongoing commitment to the minimum customer charge based only on

[48] Exhibit MEC-9, Lazar, J, P Chernick, and W. Marcus. 2020 Electric Cost Allocation for a New Era: A Manual. Regulatory Assistance Project.

facilities that are dedicated to a single customer and encourage consideration of energy as a basis for allocating shared costs of the distribution system that are not caused by demand.

Q. If the Commission wishes to revise cost-of-service allocation in this case, what do you recommend that they decide?

A. As an interim step pending future reforms of cost-of-service, the Commission could direct that Consumers Energy's tree trimming and reliability program spending be allocated to customer classes in proportion to the benefits of outage reduction implied by the Company's analysis of outage costs (i.e.., approximately 1.5% of these costs should be allocated to residential customers).[49] The Commission could also adopt a formula that allocates a portion of distribution system costs based on energy and a portion on a measure of demand other than a single peak, such as 50% energy and 50% 12 CP.

VI. RESIDENTIAL RATE DESIGN

Q. Did you examine residential rate design in this case?

A. Yes, I undertook to evaluate the residential rate design proposed by Consumers Energy through the testimony of Hubert W. Miller. In particular, I evaluated whether the proposed rate design will equitably bill residential customers for their cost of service.

Q. How did you approach your analysis?

A. I requested through discovery the full 8760-hour load profiles in the calendar 2019 historical test year for a random sample of 200 customers in each of several categories

[49] Direct testimony of Pamela L. Bolden, Figure 3, 6:13.

within the residential class. Consumers Energy was responsive to most of that request.[50] Associated with that discovery request, I received the requested data for the following categories of residential customers that I will discuss in this testimony:

- **Generic Residential Customers**, consisting of customers who are currently in rate schedule RSP, are not enrolled in AC Cycling, Peak Time Rewards, Critical Peak Pricing, Senior Citizen, Low Income Credit or Income Assistance provisions, did not have behind the meter generation in 2019, and were customers throughout 2019;
- **Senior Citizen Customers**, consisting of customers who are currently in rate schedule RSP, are not enrolled in AC Cycling, Peak Time Rewards, or Critical Peak Pricing, did not have behind the meter generation in 2019, but are enrolled in the Senior Citizen provision, and were customers throughout 2019;
- **RIA Customers**, consisting of customers who are currently in rate schedule RSP, are not enrolled in AC Cycling, Peak Time Rewards, or Critical Peak Pricing, did not have behind the meter generation in 2019, but are enrolled in the RIA provision, and were customers throughout 2019;
- **LIAC Customers**, consisting of customers who are currently in rate schedule RSP, are not enrolled in AC Cycling, Peak Time Rewards, or Critical Peak Pricing, did not have behind the meter generation in 2019, but are enrolled in the LIAC provision, and were customers throughout 2019; and

[50] Exhibit MEC-10 is Consumers Energy's answer to that discovery request MEC-CE-376.

- **DG Customers**, consisting of customers who are currently in any residential rate, who were customers throughout 2019, and had behind-the-meter solar installed throughout 2019.

I also received and analyzed data for a similar sample of customers who are enrolled in the RSH rate schedule, but since I do not have recommendations to the Commission based on that analysis, I simplified my testimony by excluding that sample from further discussion.

For each of these samples. I took the following steps:

1. Reorganized the data so that each customer is in a single column and rows represent the sequential hours of the year;
2. Added columns to identify the date and hour interval in EDT in addition to the identification of date and time in EST provided by Consumers Energy;
3. Added columns based on EDT to identify day of week, season, applicable rate interval based on the residential rate structure, cost-of-service study allocation interval, and cost-of-service study monthly peak hours;
4. Noted that data for March 16th, 2019 EDT for almost all customers was missing from all of the data sets provided by Consumers Energy, so for purposes of approximating annual statistics, data for each hour of March 16th, 2019 was estimated as the average of the corresponding data in the same hours of March 15th and March 17th, 2019;
5. Trimmed from each sample any customers using more than 30,000 kWh per year on the grounds that such customers are likely not ordinary residential customers but either have ancillary uses or are single-metered multi-dwelling buildings;

6. Calculated billing determinants and cost-of-service study allocators for each individual customer, as defined in Company testimony, exhibits, and workpapers
7. Multiplied cost-of-service allocators by the unit costs determined by Karl Boothman for COSS v2[51] and summed these for each customer in the sample to determine each customer's cost of service;
8. Multiplied billing determinants by the rates proposed by Consumers Energy in Exhibit A-16 Schedule F3.0 and summed these for each customer in the sample to determine the customer's annual bill;
9. Averaged cost of service across customers in the sample to determine average cost of service and averaged annual bills across customers in the sample to determine average bill
10. Performed various additional analyses described later in my testimony to illustrate and explain the results.

Q. As shown in Exhibit MEC-10, you requested a sample of customers residing in apartment buildings with 5 or more units but Consumers Energy was unable to provide that information. What was your intent is requesting those data?

A. Based on building physics and evidence from numerous sources, I anticipate that such customers are less "weather-sensitive" than residential customers who live in single-family dwellings or small apartment buildings and will therefore have a materially different load profile. Additionally, such apartment buildings are more likely to use electric heat, which would materially modify the load profile from that of the typical Michigan residence that

[51] Exhibit MEC-17 (KGB-7) and MEC-18 (KGB-8).

is heated with either natural gas or propane. Furthermore, low-income households are relatively more likely to live in apartment buildings, so that a deeper understanding of low-income households might be obtained by separately comparing apartment and non-apartment customers who are low-income tariff participants or generic customers. My hypothesis is that apartment-dwelling households are systematically overcharged under current and proposed residential tariffs and that a more equitable result would be achieved by treating dwellings in buildings containing 5 or more dwellings as a separate class in the cost-of-service study and by providing a distinct rate schedule for that class.

Q. What cost-of-service allocator statistics did you compute for each customer?

A. I computed the following at the meter by summing appropriately the hourly load data for each customer and adjusted these statistics to generation or distribution system voltage level based on the loss factors used by Consumers Energy in their cost-of-service study version 2.[52] The label I use in this testimony is shown parenthetically:

- COSS Allocator 100 – Energy: all hours (Annual Energy)
- COSS Allocator 103 - Energy On-Peak Summer: 6am-10pm EST, Monday-Friday, June-September by computing COSS Allocator 107 and COSS Allocator 108 which can be summed to produce Allocator 103
- Allocator 104 - Energy Off-Peak Summer: 10pm-6am EST, Monday-Friday, all hours Saturday-Sunday, June-September (SUMMER-OFF)
- Allocator 105 - Energy On-Peak Non-Summer: 6am-10pm EST, Monday-Friday, October-May by computing energy used in the hours 2pm-5pm EST,

[52] See Excel version of Consumers Energy Exhibit A-16 (EAD-2) corrected as distributed by Consumers Energy to parties in the case.

Monday-Friday (WINTER-CRITICAL) and energy used in the hours 6am-2pm EST, 5pm-10pm EST, Monday-Friday (WINTER-ON)

- Allocator 106 - Energy Off-Peak Non-Summer: 10pm-6am EST, Monday-Friday, all hours Saturday-Sunday, October-May (WINTER-OFF)
- Allocator 107 - Energy Critical On-Peak: 2pm-5pm EST, Monday-Friday, June-September (SUMMER-CRITICAL)
- Allocator 108 - Energy Summer Mid-Peak: 6am-2pm EST, 5pm-10pm EST, Monday-Friday, June-September (SUMMER-ON)
- Allocator 120 – 12 CP consisting of the sum of the hourly demand for each customer in the hours identified by Consumers Energy as their monthly system peaks (12 CP)
- Allocator 121 – 4 CP consisting of the sum of the hourly demand for each customer in the hours identified by Consumers Energy as their monthly system peaks in June, July, August, and September (4 CP)
- Allocators 236, 237, 238, and 239 consisting of each customer’s contribution to voltage peaks at various voltage levels, reflecting different loss adjustments to the customer’s load in the hour of 2019 that happened to be the voltage peak hour at all four voltage levels (Voltage 1 Peak, Voltage 2 Peak, etc.)
- Allocators 160, 161, 170, 260, 263, and 264 are all attributed to each customer based on a base customer count of “1” (Customer)
- Allocators 141, 143, 330, and Direct allocations were accounted for as adjustments proportional to the cost of service calculated from the allocators listed above.

All other allocators are accounted for in Boothman's calculations of allocator unit costs, as described in his testimony.

Q. What billing determinants did you compute for each customer?

A. I calculated the following potential billing determinants by summing the appropriate hourly loads for each customer as follows:

- Annual Energy consisting of the sum of load in all hours of the year
- WINTER-SUPER consisting of the sum of loads during the hours on weekend days and on weekdays between 11pm and 7am EDT during the months other than June, July, August, and September
- WINTER-ON consisting of the sum of loads during hours on weekdays between 2pm and 7pm EDT during the months other than June, July, August, and September
- WINTER-OFF consisting of the sum of loads during all other hours during the months other than June, July, August, and September
- SUMMER-SUPER consisting of the sum of loads during the hours on weekend days and on weekdays between 11pm and 7am EDT during the months of June, July, August, and September
- SUMMER-ON consisting of the sum of loads during all hours on weekdays between 2pm and 7pm EDT during the months of June, July, August, and September
- SUMMER-OFF consisting of the sum of loads during all other hours during the months of June, July, August, and September
- Customer Bills consisting of 12 for each customer

In computing bills under each of the residential tariffs, rates were separately applied across all appropriate billing determinants as described above for each of Production, Transmission, and Distribution and those results were summed to get the customer's annual bill. For example, for rate schedule RSP, which has a single Production rate for all hours of the winter, the same rate was applied to the WINTER-ON, WINTER-OFF, and WINTER-SUPER billing determinants. As a check on these computations, I applied these calculations and rates to the aggregate billing determinants for rate schedule RSP in Consumers Energy's Exhibit A-16 Schedule F-3 and deemed the results to be within round-off errors.

Bill credits provided to Senior Customers, RIA Customers, and LIAC Customers were not included in these calculations.

Q. You requested and Consumers Energy provided both inflow and outflow statistics for the sample of DG Customers. How did you analyze inflow and outflow?

A. In this analysis, I only considered inflow to DG customers. The Commission has previously determined that inflow should be priced using the rate design for the class to which the customer is assigned or has selected and has separately determined outflow rates at which outflow is to be credited. In this case, I am only examining the appropriateness of the inflow rate schedules for these customers.

Q. Are there important differences in the cost of service amongst the customer categories

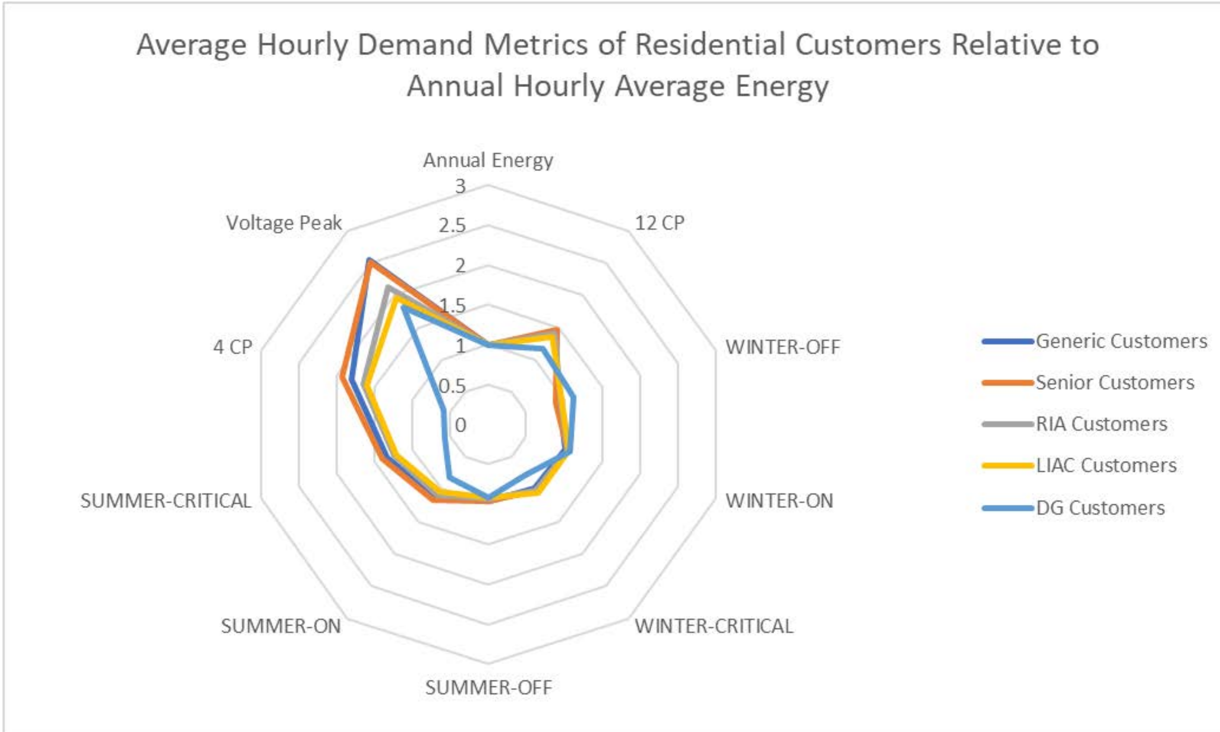
that you analyzed?

A. Yes. The following table provides averages across customers for each of the customer categories that I analyzed.

	Annual Energy (kWh)	12 CP (kW)	WINTER-OFF (kWh)	WINTER-ON (kWh)	WINTER-CRITICAL (kWh)	SUMMER-OFF (kWh)	SUMMER-ON (kWh)	SUMMER-CRITICAL (kWh)	4 CP (kW)	Voltage Peak (kW)	Cost of Service ($/yr)
Generic Customers	7658	14.85	2475	2022	450	1306	1105	300	6.33	2.22	1396
Senior Customers	6380	12.90	1966	1729	390	1078	954	263	5.61	1.83	1207
RIA Customers	8873	17.11	2918	2392	539	1463	1234	327	6.67	2.16	1471
LIAC Cusstomers	9377	17.52	3126	2566	596	1509	1245	335	6.87	2.10	1494
DG Customers	9267	14.82	3600	2597	436	1509	968	155	2.51	1.92	1222

It is apparent that there are significant differences in annual energy delivered to the various customer categories, as well as significant differences in cost of service computed according to Consumers Energy's class cost-of-service model version 2.

It is not readily apparent whether the differences in cost of service as shown in the above table simply reflect differences in total electricity consumption or reflect material differences in the patterns of electricity usage. In the following graph, I first adjusted each statistic to an hourly average for the relevant hours (dividing Annual Energy by 8760, 12 CP by 12, etc.) and then divided each of those by the hourly average of Annual Energy so that all customer categories show the value "1" for annual energy and all other values are a ratio to annual energy. This enables a clear visualization of differences amongst the customer categories.



It is now clear that Generic Customers and Senior Customers have virtually the same pattern of use even though Senior Customers use less energy on an annual basis than do Generic Customers. Low-income customers in either the RIA or the LIAC provision have very similar patterns of use and also are similar to Generic Customers in 12 CP, and Winter energy metrics but use relatively less energy than Generic Customers at costly times such as SUMMER-ON, SUMMER-CRITICAL, 4CP and Voltage Peak. DG Customers receive Annual Energy inflow that is significantly greater than Annual Energy consumption by Generic Customers but with a very different pattern in which their relative energy consumption is near normal in winter but they use significantly less relative amounts of energy during costly times including 12 CP, SUMMER-ON, SUMMER-CRITICAL, 4 CP, and Voltage Peak.

Q. Consumers Energy currently uses and proposes in this case to continue using time-

of-use rate schedules for residential customers that are designed to partly reflect the differences in cost of power production at various times. Are the differences in electricity usage pattern and cost of service that you just described reflected in customer bills using these time-of-use rate schedules?

A. The following table shows the average annual cost of service and the average annual bill using each of the proposed residential rate schedules in the future test year, based on 2019 load profiles, for the customers included in the samples provided to me by Consumers Energy. In addition, I computed the bill each customer would be under a hypothetical flat energy rate that would apply all 8760 hours of the year.

	Cost of Service	RSP Annual Bill	RSH Annual Bill	RPM Annual Bill	Flat Rate Annual Bill
Generic Customers	$ 1,396	$ 1,434	$ 1,419	$ 1,365	$ 1,427
Senior Customers	$ 1,207	$ 1,202	$ 1,199	$ 1,157	$ 1,201
RIA Customers	$ 1,471	$ 1,626	$ 1,621	$ 1,560	$ 1,633
LIAC Customers	$ 1,494	$ 1,717	$ 1,712	$ 1,647	$ 1,726
DG Customers	$ 1,222	$ 1,684	$ 1,676	$ 1,603	$ 1,707

Although there are some modest differences between cost of service and annual bills in the various rate schedules for Generic Customers and Senior Customers, the differences between cost of service and the bills under each of the rate schedules are not large.

For low-income households enrolled in RIA or LIAC, the differences between annual bills and cost of service are material. The average RIA or LIAC customer will be billed $89 to more than $200 extra per year, depending on the rate schedule to which these customers are assigned. If they are assigned to the default RSP rate schedule, RIA customers will pay an average of $155 per year in excess of their cost of service, and almost 10% of their annual bill is in excess of cost of service. If LIAC customers are assigned to the default

RSP rate schedule, they will pay an average of $223 per year in excess of their cost of service, and almost 13% of their annual bill is in excess of their cost of service.

For DG Customers with behind-the-meter solar, the differences between Annual Bills under the various rate schedules and their cost of service are substantial. If they are served under the default RSP rate schedule, they will pay an average of $462 more than their annual cost of service, with more than 27% of their annual bill in excess of their cost of service. If they choose the least costly rate schedule, RPM, they will still pay an average of $381 more than their cost of service, with almost 24% of their annual bill in excess of their cost of service.

It is notable that for each of these customer categories, the time-of-use rate schedules are superior to a flat energy rate, though not by a large amount. It is further noteworthy, that generally the RPM rate schedule, which has the most strongly time-differentiated rate structure is a better fit to cost of service than the milder rate schedules RSP and RSH.

As an additional check on the structural characteristics of my results, I calculated cost of service and annual bills for each of these customer categories as an average annual cost per kWh. That table follows:

	COSS	RSP	RSH	RPM
Generic Customers	$ 0.182	$ 0.187	$ 0.185	$ 0.178
Senior Customers	$ 0.189	$ 0.188	$ 0.188	$ 0.181
RIA Customers	$ 0.166	$ 0.183	$ 0.183	$ 0.176
LIAC Customers	$ 0.159	$ 0.183	$ 0.183	$ 0.176
DG Customers	$ 0.132	$ 0.182	$ 0.181	$ 0.173

These results reinforce a conclusion that the patterns of use for low-income customers and especially for DG Customers have lower relative costs than for Generic Customers and Senior Customers.

Q. Another aspect of equity in rate design is the degree to which annual bills of individual customers are reflective of individual cost of service. Did you assess this?

A. Yes. For each customer in each of the customer categories and for each of the rate schedules, I calculated the difference between the annual bill for that customer and their cost of service. If the annual bill exceeded cost of service, I considered that amount to be a bill excess and if that amount was less than cost of service, I considered that amount to be an undercharge. In order to account for the customer's overall electricity usage, I calculated overcharges and undercharges as a % of the customer's bill. The number of results in these calculations is large and a comprehensive table of those results is not particularly informative. It is sufficient to note that the average difference between annual bill amount and cost of service is around 25% in each case. This means that the average customer is paying a bill that is either 25% more or 25% less than that customer's cost of service.

Q. What is the cause of this relatively poor fidelity of bills to cost of service?

A. In order to diagnose the causes of the differences between bills under Consumers Energy's rate designs and cost of service, I further examined the breakdown of bills and cost of service into Production, Transmission, and Distribution within the Generic Customer category and examined the percentage differences similarly to the way in which I examined the fidelity of total bills to total cost of service. The average difference between the Production bill and Production cost of service was about 20% of the Production bill. The average difference between the Transmission bill and Transmission cost of service was about 19% of the Transmission bill. The average difference between the Distribution bill and Distribution cost of service was 39%. Thus, while I believe that the fidelity of rate design to cost of service can be further improved for both Production and Transmission, the most important way to improve the fidelity of bills to cost of service is to reform distribution rate design.

Q. In what way should distribution rate design be reformed?

A. Earlier in this testimony, I recommended that Commission direct certain changes in the distribution cost-of-service model used by Consumers Energy. Rather than propose a change in distribution rate design in this case, I recommend that the Commission direct Consumers Energy to submit in their next rate case a time-of-use rate design for distribution costs, calibrated to the structure of distribution cost of service. It is clear that a flat rate per kWh for distribution throughout the year does not reflect the allocation of costs to customers or categories of customers based on their contributions to the voltage peak. Since there are important differences in the ratio of contribution to voltage peak to annual energy both amongst customers generally and between Generic Customers, low-income customers, and DG Customers, only pricing that reflects those differences is likely to more accurately reflect cost of service.

Q. Will a reform of distribution rate design correct any of the patterns of excess bills for low-income customers or DG Customers that you demonstrated above?

A. Time-of-use distribution rates will likely improve the fidelity of bills to cost of service for both low-income customers and DG Customers as both categories of customers show lower contributions to Voltage Peak than to Annual Energy. Distribution rates that are higher at times closer to the time of Voltage Peak and lower at other times will shift in the right direction. Whether this reform will be sufficient depends on the cost-of-service allocation and rate design ultimately chosen, but I consider it unlikely to fully resolve these problems unless the distribution cost-of-service model is changed to emphasize a larger part of the year in determining cost of service or the rate design sets very high rates for summer afternoons and very low rates the rest of the year.

Q. Since reform of distribution rate design is unlikely to fully correct for the inequities of current rate design for low-income customers and for DG Customers, what do you recommend to the Commission?

A. Both low-income customers and DG Customers have sufficiently different patterns of electricity use as reflected in cost-of-service study allocator statistics that the Commission should require Consumers Energy to treat them as separate classes in the cost-of-service study that Consumers Energy submits in its next rate case. Rate design for each should then be calibrated to the results of that cost-of-service analysis, just as it is for any other class.

Q. Is there any action the Commission should take with respect to residential rate design in this case?

A. Yes, the Commission should act to move residential customers toward their least-cost rate schedules.

In the case of low-income customers who are in the RIA and LIAC provisions and any other low-income customers with whom the Consumers Energy engages going forward, the Commission should require Consumers Energy to move those customers into the least-cost rate schedule for that customer, on an opt-out basis and to provide consumer education about how to manage electricity use to minimize the bill within that rate schedule. In the samples of RIA Customers and LIAC Customers I analyzed for this testimony, applying the least-cost tariff to the existing usage pattern would save the average RIA Customer $66 per year and the average LIAC Customer $70 per year. In most cases, the least-cost tariff is the RPM tariff, which offers many opportunities to manage bills by timing electricity usage and further reduce the bill. In addition, the Commission should require Consumers Energy to specifically and intentionally offer low-income customers who are in the RIA and LIAC provisions and any other low-income customers with whom Consumers Energy engages going forward the opportunity to participate in demand response, energy waste reduction programs, and any other bill-reducing programs for which they might be eligible; those offers should be structured so that they are either opt-out or require a decision by the customer one way or another rather than leaving the higher-cost option as the default.[53] My colleague Tanya Paslawski testifies more comprehensively on this point.

For all other customers, the Commission should require that Consumers Energy include in each monthly bill for each customer either a statement that the customer is eligible for a specific alternative rate schedule and would have had bill savings of a specific amount had the customer been in that rate schedule, or a statement that the customer is in the least-cost rate schedule based on their electricity use during the preceding twelve months. Since opt-in rates are likely to be slow even for an attractive offer, this will produce only a gradual migration to alternative rate schedules.

[53] For further discussion of this see the Testimony of Tanya Paslawski in this case.

For DG Customers, the Commission should ensure that those customers are free to choose any of the available residential rate schedules (except potentially for RSM- Residential Non-transmitting Meters) so as to minimize their bills. The Commission should require that the "shadow billing" to all residential customers that I recommend above is done for DG Customers considering both the inflow and outflow parts of the tariff.

Q. Are there reasons aside from equitable billing that the Commission should consider your rate design recommendations?

A. Yes. Rate designs that more accurately reflect cost of service generally also provide good price signals, informing customers when power is expensive to provide and when it is not. This will lead to more efficient behavior and investments. In the near future, appropriately structured time of use rates will encourage energy waste reduction at key times when it reduces the cost of Consumers Energy's services and encourage participation in demand response programs that enable avoidance of the use of power when it is expensive to provide. In the longer run, it will encourage both market development and habits by which customer demand becomes more flexible and automated so as to accommodate increasing use of wind and solar generation that produce time-varying amounts of power. Time-of-use rates and critical event programs and pricing are the necessary steps toward that future.

<u>VII. CONCLUSIONS AND RECOMMENDATIONS</u>

Q. Please summarize your conclusions and recommendations to the Commission.

A. I recommend that the Commission:

1. In its overall consideration of this case, look for economically efficient ways to improve reliability of the distribution system, and look for ways to significantly limit the growth of residential rates.

2. Reject Consumers Energy's request to increase its authorized return on equity from 10% to 10.5% and consider further reducing authorized return on equity to 9.5%, based on Consumers Energy's relative performance.

3. Revise Consumers Energy's projected test year costs by:

a. Reducing all Consumers Energy operations and maintenance purchased goods and services cost projections by 4.26% as shown on the table on page 31 of my testimony,

b. Reducing all Consumers Energy operations and maintenance labor cost projections by 1.64% as shown on the table on page 31 of my testimony,

c. Reducing Consumers Energy's projected revenue requirements for electric distribution O&M by $10 million based on productivity improvements,

d. Requiring Consumers Energy to include and support the value of an explicit productivity improvement factor (or multiple factors for different portions of the business) in test year cost projections in future rate cases.

4. With respect to the cost-of-service allocation study,

a. Decline to accept the voltage peak method and version 2 of the cost-of-service study as proposed by Consumers Energy in this case,

b. Endorse the idea of moving away from the class peak method when an acceptable alternative is proposed,

c. Direct Consumers Energy to include in its next rate case at least one cost-of-service study that incorporates the diversity of peak hours on various sections of the distribution system (such as substations) and the use of the metrics used in actual engineering practices (such as the use of root mean square load) as measures of demand,

d. Remind Consumers Energy of the Commission's ongoing commitment to the minimum customer charge based only on facilities that are dedicated to a single customer and encourage consideration of energy as a basis for allocating shared costs of the distribution system that are not caused by demand.

5. With respect to residential rate design,

a. Direct Consumers Energy to propose time-of-use distribution rates in its next rate case.

b. Direct Consumers Energy to conduct a study to determine whether load profiles of customers living in apartment buildings with at least 5 dwelling units are materially different than for other residential customers.

c. Direct Consumers Energy to treat low-income customers and residential distributed generation customers as separate classes from other residential customers in the cost-of-service study in its next rate case and to then present distinct rate schedules or tariff provisions that reconcile revenues from these classes to the required revenue as determined in the cost-of-service study.

d. Direct Consumers Energy to begin computing and notifying all customers in their monthly bills of the rate schedule that would have resulted in the lowest bill over the preceding 12 months and the amount they would have saved by using that rate schedule.

e. Direct Consumers Energy to begin transferring customers using the RIA and LIAC tariff provisions and any low-income customers with which Consumers Energy engages in the future to their least-cost rate schedule, on an opt-out basis.

Q. Does that complete your testimony?

A. Yes.

Douglas B. Jester

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Professional experience

January 2011 – present 5 Lakes Energy

Managing Partner

Managing 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 electric 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 - 2015 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 of 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, Computer Science, 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, 2007-2017

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 – 2018.

East Lansing Brownfield Authority Board Member and Vice-Chair, 2010 – 2018.

East Lansing Downtown Management Board and Chair, 2010 – 2016

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

City of East Lansing Advisory Commissioner to the Lansing Board of Water and Light, 2017 – present.

State of Michigan UP Energy Task Force, 2019-present, appointed by Governor Whitmer.

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 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.

- Participant in Michigan Public Service Commission Power Quality and Reliability Standards work group.
- Participant in Michigan Public Service Commission Interconnection and Worker Safety work group.
- Participant in Michigan Public Service Commission Demand Response work group.
- Participant in Michigan Public Service Commission Integrated Resource Planning Filing Requirements and Specifications work group.
- Participant in Michigan Public Service Commission Program and Technology Pilots work group
- Participant in Michigan Public Service Commission Electric Distribution Planning work 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)
  - 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); and
  - Case U-20697 (Consumers Energy General Rate Case)
- Expert witness before the Delaware Public Service Commission
  - Case 17-1094 (Electric Vehicle Charging Stations)
- Expert witness before the Indiana Public Utilities Commission
  - Cause 45378 (Vectren Distributed Generation Tariff)
- 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)
  - Case ER-2018-0145 (KCP&L General Rate Case)
- Expert witness before the Kentucky Public Service Commission
  - Case 2016-00370 (Kentucky Utilities General Rate Case)
  - Case 2018-00294 (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)
- Expert witness before the Rhode Island Public Utilities Commission
  - Case 4780 (National Grid Grid Modernization)
- Coauthored “Charge without a Cause: Assessing Utility Demand Charges on Small Customers”
- 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.
- Under contract to Institute for Energy innovation, prepared report on the role of storage in Michigan’s electric power system

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.

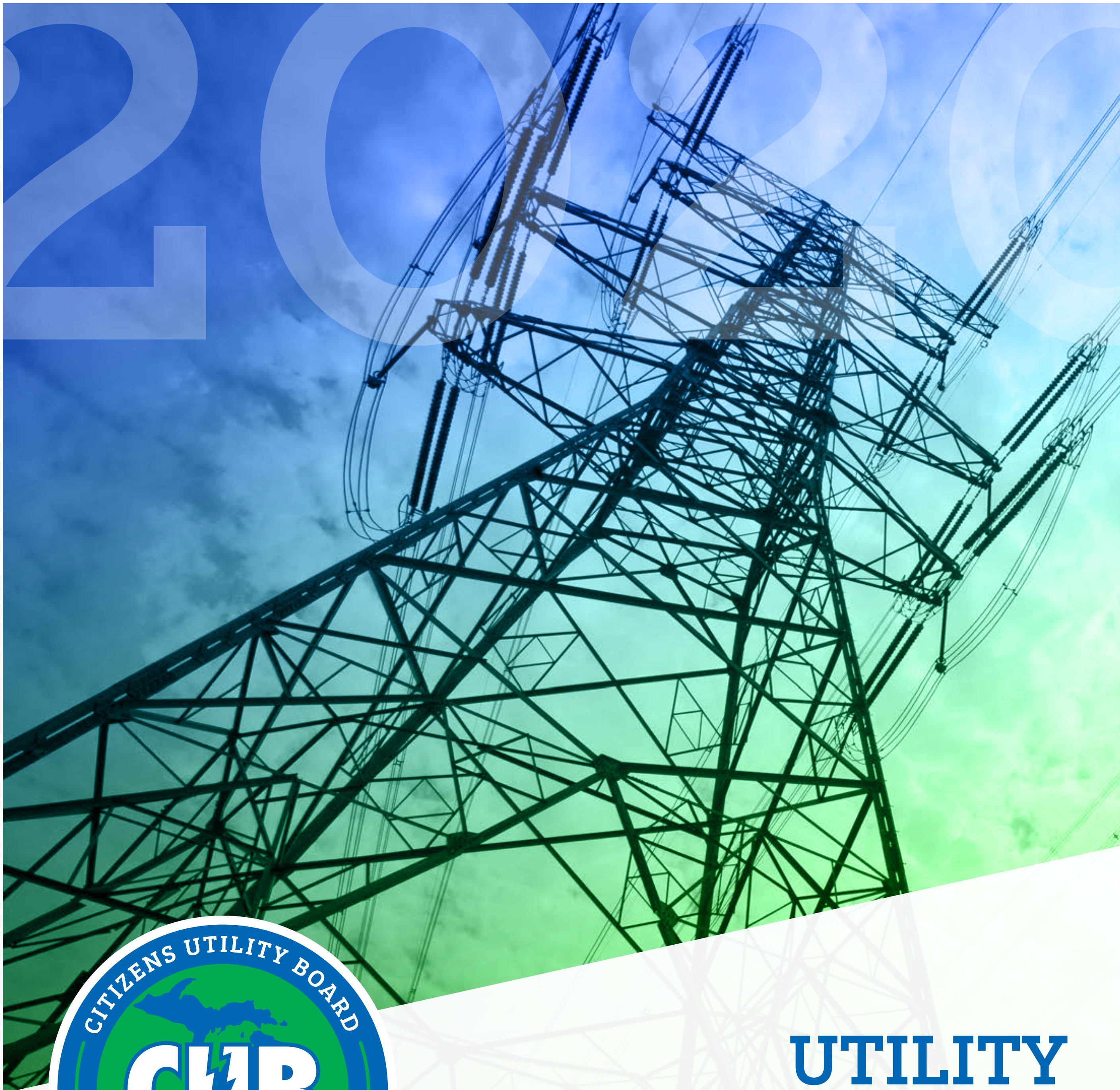
For Verizon Business

- 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.



CITIZENS UTILITY BOARD
CUB
Empowering Michigan Consumers

UTILITY PERFORMANCE REPORT

RANKING MICHIGAN AMONGST THE STATES • 2020 EDITION

The Citizens Utility Board of Michigan (CUB of MI) was formed in 2018 to represent the interests of residential energy customers across the state of Michigan. CUB of MI educates and engages Michigan consumers in support of cost-effective investment in energy efficiency and renewable energy and against unfair rate increase requests. CUB of MI gives a voice to Michigan utility customers and helps to ensure that citizens of the state pay the lowest reasonable rate for utility services and also benefit from the environmental implications of investment in clean energy. CUB of MI is a nonpartisan, nonprofit organization whose members are individual residential customers of Michigan's energy utilities. For more information, visit www.cubofmichigan.org.

This report was prepared for Citizens Utility Board of Michigan by 5 Lakes Energy. 5 Lakes Energy is a Michigan-based policy consulting firm dedicated to advancing policies and programs that promote clean energy and sound water policy for a resilient environment. For more information, visit https://5lakesenergy.com/.

UTILITY PERFORMANCE: RANKING MICHIGAN AMONGST THE STATES

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INTRODUCTION

Reliability, affordability, and management of environmental impacts are commonly considered to be the primary performance criteria for electric utilities. This report provides a scorecard measuring the aggregate and individual performance of Michigan's electric utilities on these criteria in comparison to the aggregate performance of 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 the historical effectiveness of the state's utility regulatory policy.

Most observers have similar considerations for evaluating gas utilities, but because variations between utilities with respect to safety, reliability, and environmental effects are primarily related to pipeline condition and management, gas utilities may primarily be evaluated on cost or affordability and gas losses. This report also provides a scorecard measuring the aggregate and individual performance of Michigan's gas utilities.

Michigan Summary of Rankings	
RELIABILITY SECTION	
Metric	2018 Michigan Rank (worst-best)
SAIDI with Major Event Days	13
SAIDI without Major Event Days	9
SAIFI with Major Event Days	24
SAIFI without Major Event Days	25
CAIDI with Major Event Days	8
CAIDI without Major Event Days	2
AFFORDABILITY SECTION	
Metric	2018 Michigan Rank (worst-best)
Average Annual Household Electricity Expenditure	36
Average Annual Household Non-Electricity Energy Expenditure	10
Total Household Energy Expenditure	17
Total Household Energy Expenditure as a % of Median Income	15
Residential Electricity Price	11
Commercial Electricity Price	14
Industrial Electricity Price	24
All Sector Electricity Price	14
ENVIRONMENTAL SECTION	
Metric	2018 Michigan Rank (worst-best)
Carbon Dioxide Emission Intensity	19
Total Carbon Dioxide Emissions	9
Sulfur Dioxide Emission Intensity	10
Total Sulfur Dioxide Emissions	6
Nitrogen Oxide Emission Intensity	18
Total Nitrogen Oxide Emissions	7
Generation from Renewable Sources	30
Generation from Renewable Sources Excluding Conventional Hydro	38

Renewable Generation as a % of Total Generation	20
Renewable Generation Excluding Hydro as a % of Total Generation	27
Renewable Generation as a % of Total Sales	21
Renewable Generation Excluding Hydro as a % of Total Sales	28
Generation from Carbon-free and Renewable Sources	38
Carbon-free and Renewable Generation as a % of Total Sales	26
Carbon-free and Renewable Generation as a % of Total Generation	25
Generation from Carbon-free Sources	38
Carbon-free Generation as a % of Total Sales	27
Carbon-free Generation as a % of Total Generation	24
GAS SECTION	
Metric	2018 Michigan Rank (worst-best)
Average Annual Household Natural Gas Expenditure	19
Natural Gas Price: Residential Sector	43
Natural Gas Price: Commercial Sector	38
Natural Gas Price: Industrial Sector	22
Natural Gas Volume: Residential Sector	4
Natural Gas Volume: Commercial Sector	5
Natural Gas Volume: Industrial Sector	11
Natural Gas Losses	10
Natural Gas Usage per Customer: Residential Sector	4
Unaccounted-for Natural Gas	10
Natural Gas Losses as a % of Total Consumption	18
Unaccounted-for Natural Gas as a % of Total Consumption	16

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. As of May 2020, the Energy Information Administration (EIA) of the US Department of Energy has released reliability, price, emissions, and generation data for 2018. All time-series tables display states or utilities ranked based on their performance in the most recent reported year.

In many graphs and tables, Michigan is also compared against its "peer group" of states including Ohio, Indiana, Illinois, Wisconsin, and Minnesota. Comparing Michigan to a group of states which may have similar weather, population dynamics, industrial activity, and market conditions, introduces some context for the environmental, affordability, and reliability statistics.

ELECTRIC RELIABILITY METRICS

Electricity is one of the essentials of modern life, impacting both comfort and public safety, so reliability of electricity supply is an important attribute of utility performance. 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. These may occur because storms break power lines, animals touch pairs of power lines and cause a “short,” equipment fails, and many other proximate causes.

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 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 EIA 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 latest available reliability data from EIA are for calendar year 2018. The EIA collects SAIDI and SAIFI metrics with and without Major Event Days (MED). Major Event Days are a statistical classification, defined by the 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.

We computed SAIDI, SAIFI, and CAIDI with and without Major Event Days by state using an average of the reporting utilities within each state, weighted by the number of customers served by each utility.[1]

The following table shows Michigan’s 2018 performance on each of these standard reliability metrics, with and without Major Event Days. 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.

2018 Metric	With Major Event Days	Without Major Event Days
Annual minutes outage per customer (SAIDI)	443 minutes (13th worst)	185 minutes (9th worst)
Annual outages per customer (SAIFI)	1.37 outages (24th worst)	1.05 outages (25th worst)
Average restoration time per outage (CAIDI)	319 minutes (8th worst)	175 minutes (2nd worst)

[1] SAIFI values over 500 were considered data entry errors.

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 1 and Figure 2 in 2018 Michigan ranked 13th worst among the states in overall average number of minutes of outage per customer (SAIDI with Major Event Days) over the year and 9th worst in number of minutes of outage per customer (SAIDI without Major Event Days) over the year.

Annual data from 2013-2018 in Figure 3 and Figure 4 shows that Michigan's performance in SAIDI without Major Event Days has remained very high relative to other states over the last six years, while SAIDI with Major Event Days has ranged from high to very high relative to other states.

Names of Michigan's neighboring states are shown in bold to facilitate comparison within the region. Compared to customers in neighboring states, Michigan customers experienced the most minutes of outage per year on average.

Figure 1: 2018 SAIDI with MED

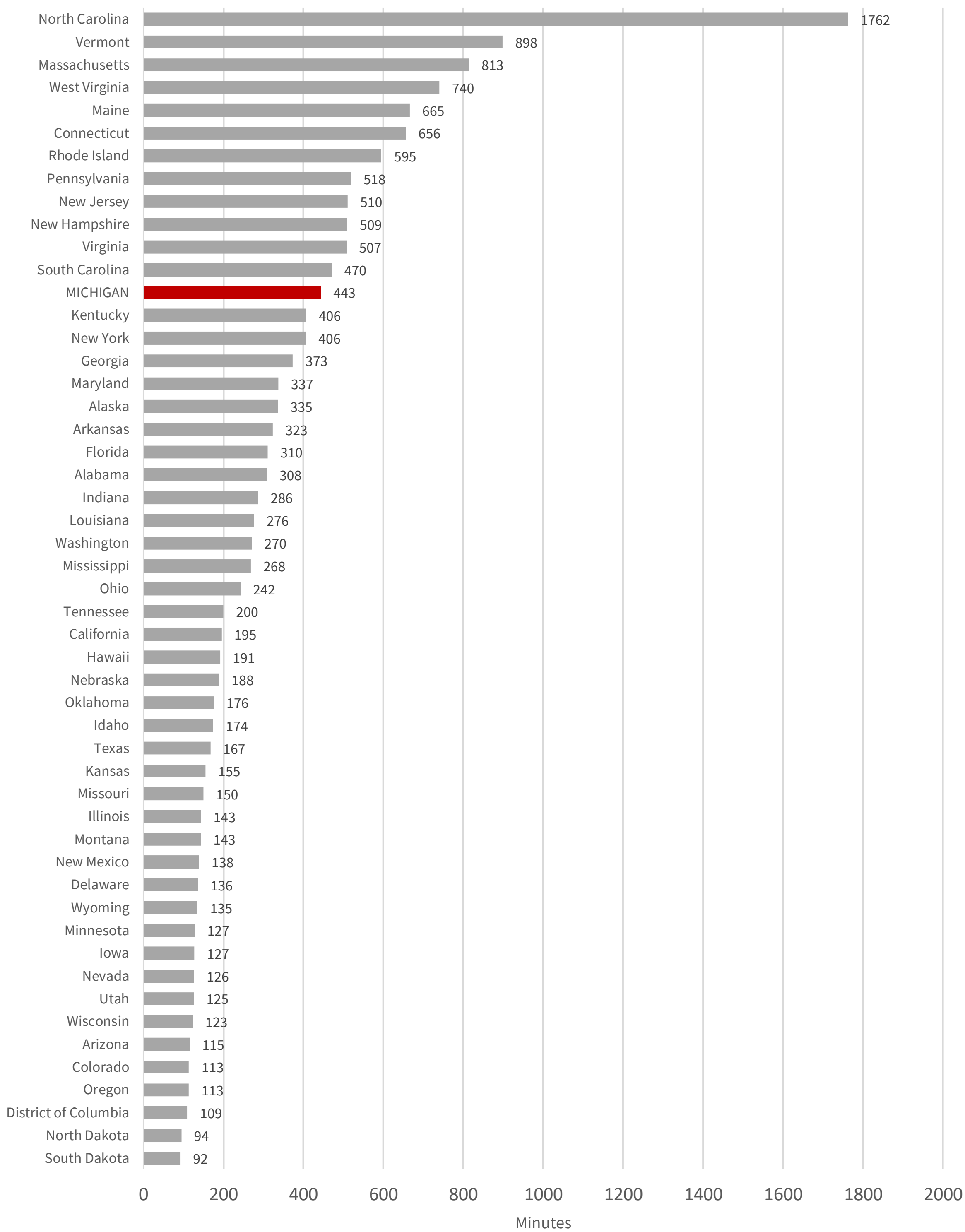


Figure 2: 2018 SAIDI without Major Event Days (MED)

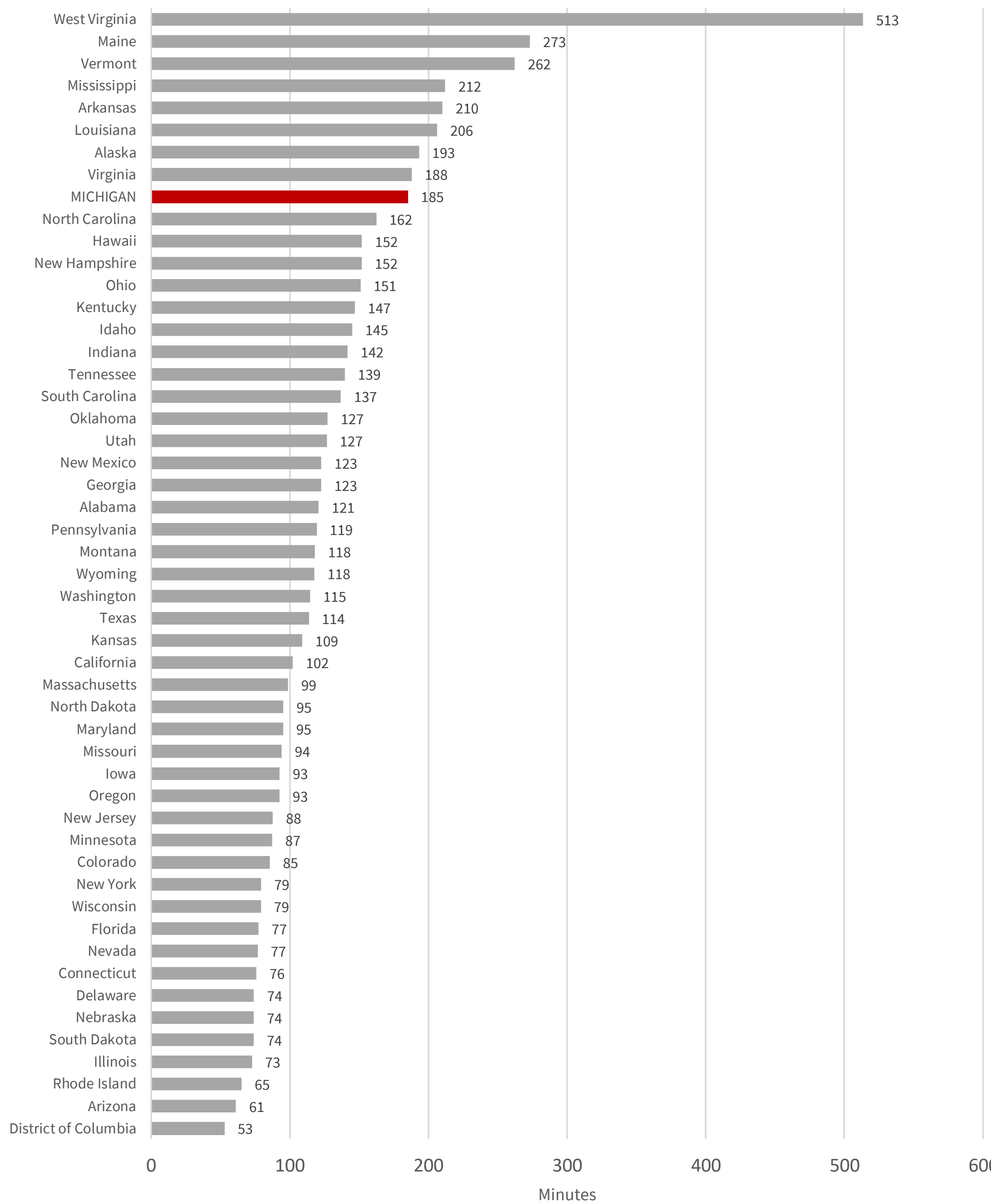


Figure 3: SAIDI with MED

Average Minutes of Outage per Customer per Year (SAIDI) with Major Event Days						
State	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
North Carolina	228	440	210	823	265	1762
Vermont	7	741	204	352	874	898
Massachusetts	427	124	91	145	275	813
West Virginia	542	663	815	743	691	740
Maine	16	474	102	535	2493	665
Connecticut	79	86	104	174	291	656
Rhode Island	783	54	342	169	728	595
Pennsylvania	139	400	157	126	177	518
New Jersey	166	112	261	137	86	510
New Hampshire	189	725	105	192	1113	509
Virginia	449	176	201	237	190	507
South Carolina	111	755	224	1647	373	470
MICHIGAN	785	551	350	268	779	443
Kentucky	227	283	200	192	194	406
New York	86	67	87	107	227	406
Georgia	138	235	241	420	1042	373
Maryland	112	236	124	120	116	337
Alaska	358	253	597	195	153	335
Arkansas	251	212	303	397	395	323
Florida	82	92	85	337	2381	310
Alabama	230	197	209	174	316	308
Indiana	226	234	242	250	211	286
Louisiana	253	196	312	378	378	276
Washington	155	303	550	224	271	270
Mississippi	178	184	297	282	557	268
Ohio	217	170	172	173	248	242
Tennessee	129	185	219	208	482	200
California	98	103	118	117	233	195
Hawaii	145	262	266	126	252	191
Nebraska	128	120	87	90	154	188
Oklahoma	611	109	824	317	290	176
Idaho	255	240	459	201	311	174
Texas	182	188	269	211	481	167
Kansas	244	139	265	168	365	155
Missouri	304	126	167	204	264	150
Illinois	184	195	169	135	120	143
Montana	161	139	287	154	215	143
New Mexico	149	82	122	136	141	138
Delaware	158	169	190	149	154	136
Wyoming	369	193	187	193	216	135
Minnesota	359	120	154	302	129	127
Iowa	122	164	97	117	119	127
Nevada	66	74	107	96	114	126
Utah	190	187	200	190	139	125
Wisconsin	143	139	105	136	204	123
Arizona	74	84	90	86	91	115
Colorado	127	83	109	164	228	113
Oregon	167	277	200	285	313	113
District of Columbia	124	96	112	115	58	109
North Dakota	113	81	104	120	87	94
South Dakota	1100	107	126	216	95	92

Figure 4: SAIDI without MED

Average Minutes of Outage per Customer per Year (SAIDI) without Major Event Days						
State	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West Virginia	418	450	458	439	452	513
Maine	4	83	87	264	238	273
Vermont	2	212	204	270	247	262
Mississippi	117	147	187	180	201	212
Arkansas	207	203	213	208	178	210
Louisiana	98	111	152	179	184	206
Alaska	222	195	162	181	137	193
Virginia	135	141	146	163	140	188
MICHIGAN	199	179	178	193	179	185
North Carolina	111	118	127	146	146	162
Hawaii	116	117	117	96	104	152
New Hampshire	123	122	94	141	151	152
Ohio	112	130	141	128	143	151
Kentucky	146	158	116	137	120	147
Idaho	172	183	263	170	247	145
Indiana	107	115	120	126	131	142
Tennessee	92	105	121	157	133	139
South Carolina	97	97	119	120	118	137
Oklahoma	109	101	177	149	138	127
Utah	176	148	156	106	115	127
New Mexico	98	75	99	101	111	123
Georgia	87	90	106	122	121	123
Alabama	114	122	122	115	116	121
Pennsylvania	99	100	99	101	109	119
Montana	139	124	141	128	162	118
Wyoming	169	178	166	150	191	118
Washington	97	115	110	111	132	115
Texas	105	112	137	129	133	114
Kansas	111	106	127	132	131	109
California	84	86	93	99	103	102
Massachusetts	83	82	74	113	91	99
North Dakota	88	78	81	98	64	95
Maryland	111	85	109	105	86	95
Missouri	88	90	93	83	96	94
Iowa	77	93	86	92	95	93
Oregon	82	106	101	101	111	93
New Jersey	123	79	65	86	71	88
Minnesota	87	75	78	88	73	87
Colorado	82	78	82	82	78	85
New York	43	46	77	83	72	79
Wisconsin	75	71	69	77	78	79
Florida	74	84	77	82	78	77
Nevada	51	61	55	74	88	77
Connecticut	55	86	70	92	68	76
Delaware	129	114	115	103	83	74
Nebraska	54	66	52	54	70	74
South Dakota	171	100	103	80	76	74
Illinois	84	92	89	81	73	73
Rhode Island	57	54	64	69	59	65
Arizona	55	52	55	58	51	61
District of Columbia	124	82	112	115	58	53

SAIFI – Outages per Customer per Year

Minutes of outage per customer per year (SAIDI) can be understood as the product of the number of outages per customer per year (SAIFI) and the average time to restore power after an outage (CAIDI).

Figure 5 and Figure 6 show Michigan's number of outages per customer per year compared to other states, with and without Major Event Days. In 2018, Michigan performed near the median in outages per customer (SAIFI with Major Event Days), ranking 24th worst overall. When Major Event Days are excluded, Michigan remains average, ranking 25th worst overall. Michigan performed worse than its peer states, with only Ohio and Indiana customers experiencing more outages per customer per year.

Annual data from 2013-2018 in Figure 7 and Figure 8 show that Michigan's SAIFI value, with and without Major Event Days, has been consistently average relative to other states.

Figure 5: 2018 SAIFI with MED

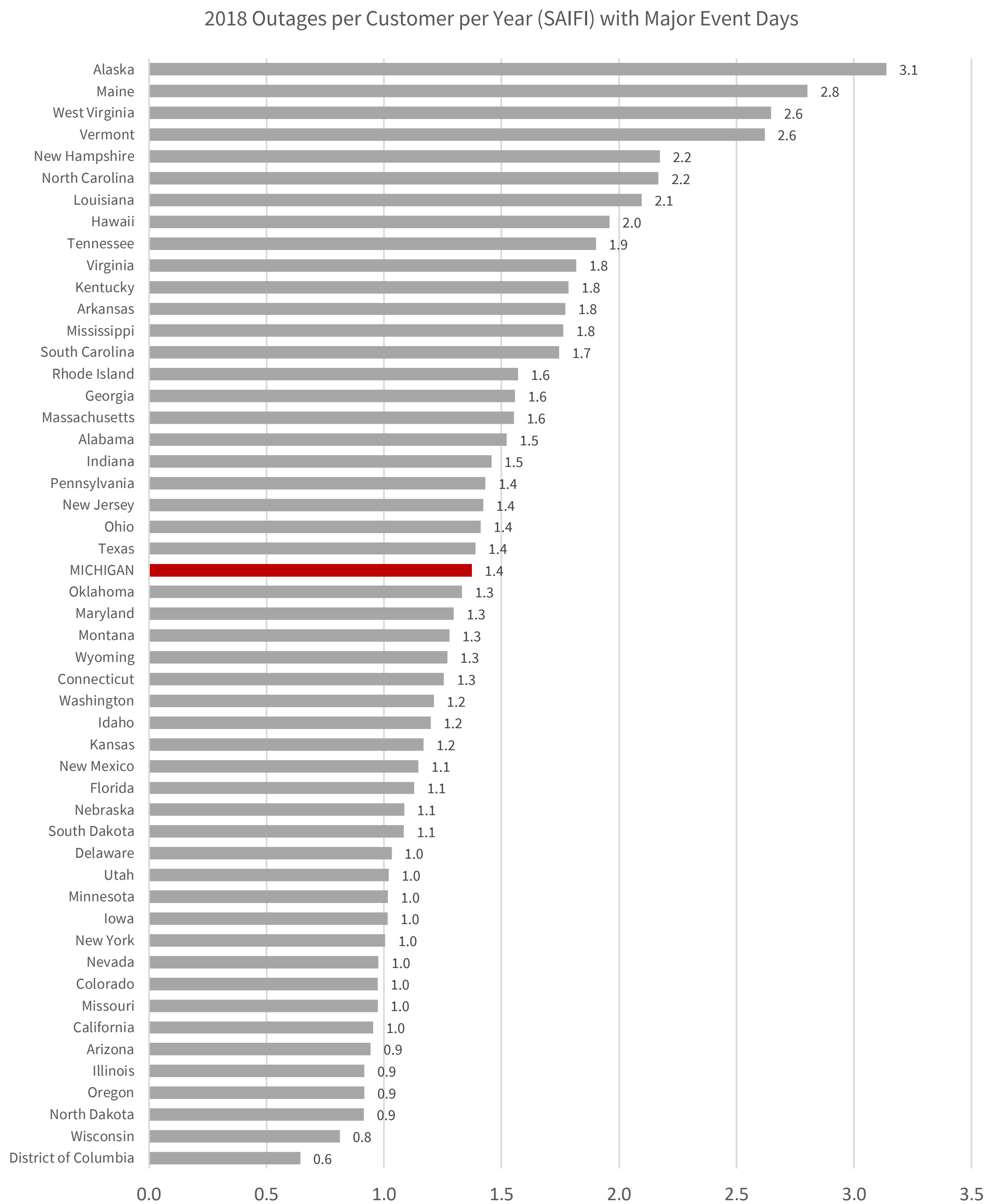


Figure 6: 2018 SAIFI without MED

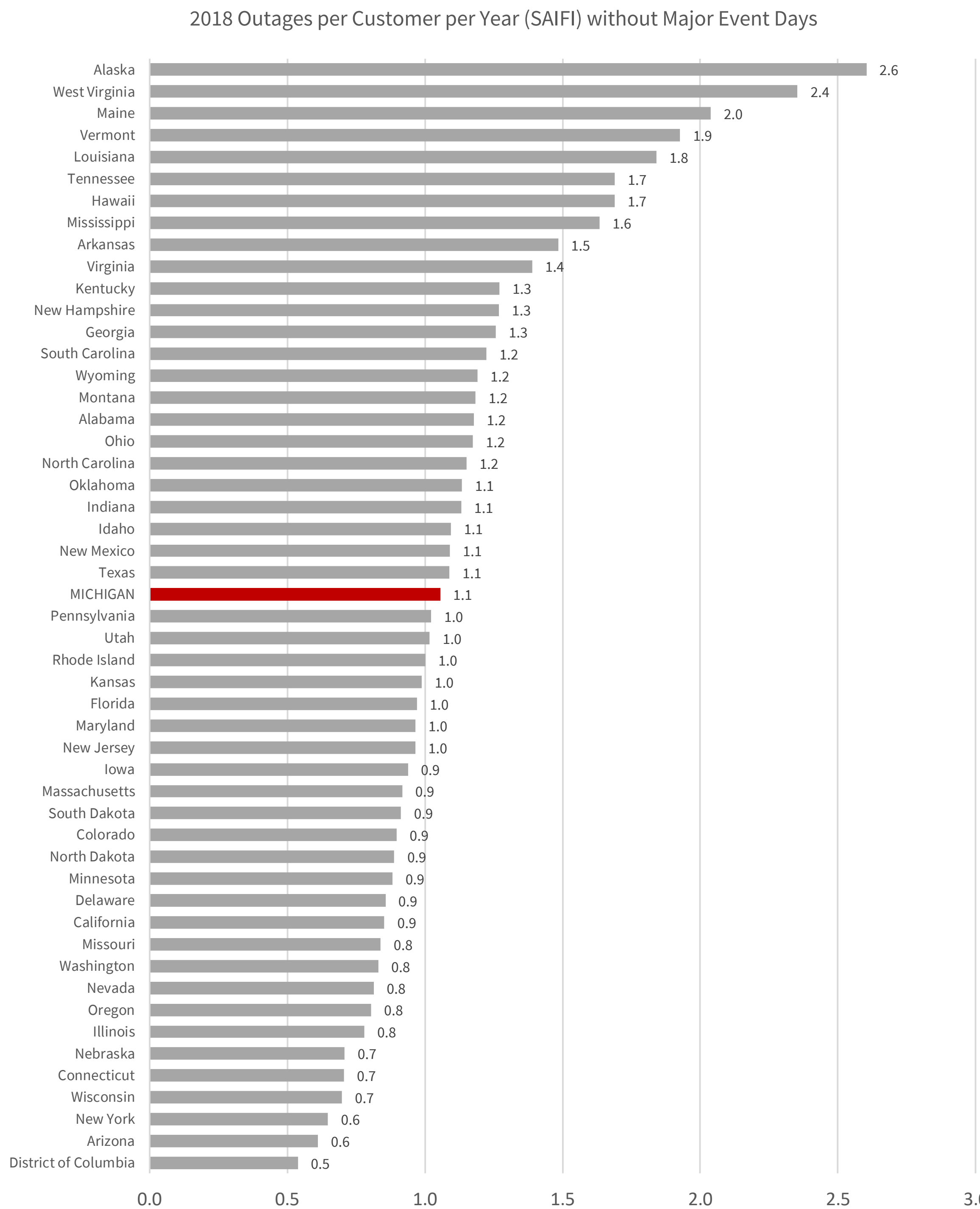


Figure 7: SAIFI with MED

Outages per Customer per Year (SAIFI) with Major Event Days						
State	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Alaska	6.1	2.4	2.6	2.3	1.7	3.1
Maine	2.9	10.9	1.9	2.7	3.1	2.8
West Virginia	2.3	2.4	2.4	2.4	2.3	2.6
Vermont	2.2	2.2	1.7	1.9	2.4	2.6
New Hampshire	2.2	2.3	1.4	1.5	2.3	2.2
North Carolina	2.2	1.5	1.3	1.8	1.3	2.2
Louisiana	2.4	2.4	2.3	2.1	2.3	2.1
Hawaii	2.1	2.3	3.0	1.9	2.1	2.0
Tennessee	3.0	1.7	2.0	2.0	1.8	1.9
Virginia	2.9	1.4	1.4	1.5	1.4	1.8
Kentucky	1.8	1.9	1.3	1.5	1.3	1.8
Arkansas	1.8	1.8	2.0	2.0	2.0	1.8
Mississippi	1.5	1.5	1.8	1.9	2.2	1.8
South Carolina	1.8	1.8	1.4	2.4	1.6	1.7
Rhode Island	1.3	0.8	1.2	1.2	1.2	1.6
Georgia	1.3	1.5	1.5	1.5	2.4	1.6
Massachusetts	1.1	1.0	0.8	1.0	1.1	1.6
Alabama	3.2	3.2	1.7	1.6	2.0	1.5
Indiana	1.2	1.3	1.3	1.3	1.3	1.5
Pennsylvania	1.0	1.2	1.0	1.1	1.1	1.4
New Jersey	1.3	1.0	1.0	1.2	0.9	1.4
Ohio	1.2	1.2	1.2	1.2	1.4	1.4
Texas	1.5	1.4	2.0	1.6	1.7	1.4
MICHIGAN	1.5	2.6	2.2	1.1	1.4	1.4
Oklahoma	1.8	1.0	1.7	1.6	1.4	1.3
Maryland	4.1	1.3	1.1	1.1	1.0	1.3
Montana	1.4	1.1	1.8	1.3	1.6	1.3
Wyoming	1.8	1.5	1.5	1.5	1.7	1.3
Connecticut	0.7	0.7	0.7	1.1	0.9	1.3
Washington	1.1	1.5	1.7	1.2	1.3	1.2
Idaho	1.6	1.3	1.7	1.4	1.7	1.2
Kansas	1.6	1.3	2.3	1.4	1.5	1.2
New Mexico	1.1	0.8	3.4	1.8	1.3	1.1
Florida	1.1	1.2	1.1	1.4	2.0	1.1
Nebraska	1.0	1.3	0.7	0.7	0.9	1.1
South Dakota	1.8	0.9	1.0	1.2	1.1	1.1
Delaware	1.5	1.4	1.5	1.4	1.1	1.0
Utah	1.6	1.4	1.4	1.3	1.1	1.0
Minnesota	1.7	1.4	1.0	1.2	0.9	1.0
Iowa	1.0	1.2	1.0	1.0	1.0	1.0
New York	0.7	0.7	0.7	0.8	0.8	1.0
Nevada	0.7	0.7	0.7	0.8	0.9	1.0
Colorado	1.1	0.9	1.0	1.1	1.2	1.0
Missouri	1.1	1.1	1.1	1.0	1.2	1.0
California	0.9	0.9	0.9	1.0	1.3	1.0
Arizona	0.8	0.8	2.9	0.8	0.9	0.9
Illinois	1.1	1.1	1.1	1.0	0.9	0.9
Oregon	0.8	1.3	1.2	1.3	1.4	0.9
North Dakota	0.9	0.9	1.1	1.0	0.9	0.9
Wisconsin	0.8	0.8	1.3	1.0	0.9	0.8
District of Columbia	0.9	0.7	0.7	0.8	0.6	0.6

Figure 8: SAIFI without MED

Outages per Customer per Year (SAIFI) without Major Event Days						
State	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Alaska	2.3	2.0	1.8	1.9	1.8	2.6
West Virginia	1.7	2.1	2.2	2.1	2.1	2.4
Maine	2.0	2.5	1.8	2.2	2.2	2.0
Vermont	1.9	1.5	1.8	1.8	1.9	1.9
Louisiana	1.4	1.5	1.8	1.8	1.7	1.8
Tennessee	2.8	1.5	1.7	1.9	1.4	1.7
Hawaii	1.6	1.8	1.7	1.3	1.2	1.7
Mississippi	1.2	1.3	1.6	1.7	1.6	1.6
Arkansas	1.6	1.6	1.8	1.7	1.5	1.5
Virginia	1.2	1.2	1.2	1.3	1.2	1.4
Kentucky	1.4	1.5	1.1	1.3	1.1	1.3
New Hampshire	1.3	1.6	1.4	1.4	1.5	1.3
Georgia	1.2	1.1	1.3	1.3	1.2	1.3
South Carolina	1.7	1.1	1.2	1.2	1.1	1.2
Wyoming	1.6	1.5	1.4	1.4	1.6	1.2
Montana	1.3	1.1	1.4	1.1	1.4	1.2
Alabama	2.9	2.9	1.2	1.2	1.1	1.2
Ohio	1.0	1.1	1.1	1.1	1.1	1.2
North Carolina	1.9	1.0	1.1	1.1	1.1	1.2
Oklahoma	1.0	1.0	1.1	1.3	1.1	1.1
Indiana	1.0	1.0	1.0	1.0	1.0	1.1
Idaho	1.4	1.1	1.4	1.2	1.6	1.1
New Mexico	0.9	0.8	1.6	1.4	1.1	1.1
Texas	1.2	1.2	1.4	1.3	1.3	1.1
MICHIGAN	0.9	0.9	1.0	1.0	1.0	1.1
Pennsylvania	0.9	0.9	0.9	1.0	0.9	1.0
Utah	1.3	1.2	1.3	1.0	0.9	1.0
Rhode Island	0.7	0.8	0.9	1.0	0.8	1.0
Kansas	1.2	1.2	1.7	1.2	1.2	1.0
Florida	1.0	1.1	1.1	1.1	1.0	1.0
Maryland	4.4	1.0	1.0	1.0	0.9	1.0
New Jersey	1.2	0.9	0.8	1.0	0.9	1.0
Iowa	0.9	1.0	0.9	0.9	0.9	0.9
Massachusetts	0.9	0.8	0.7	0.9	0.6	0.9
South Dakota	1.1	0.7	0.9	0.9	1.0	0.9
Colorado	1.0	0.9	0.9	0.9	0.9	0.9
North Dakota	0.9	1.0	0.9	1.0	0.8	0.9
Minnesota	1.3	1.3	0.8	0.9	0.8	0.9
Delaware	1.3	1.2	1.3	1.2	1.0	0.9
California	0.8	0.8	0.8	0.9	0.9	0.9
Missouri	0.8	0.9	0.9	0.8	0.8	0.8
Washington	0.8	1.0	0.8	0.8	0.9	0.8
Nevada	0.6	0.6	0.6	0.7	0.8	0.8
Oregon	0.6	0.9	0.7	0.8	0.9	0.8
Illinois	0.9	0.9	0.9	0.8	0.8	0.8
Nebraska	0.5	0.7	0.5	0.5	0.7	0.7
Connecticut	0.6	0.7	0.6	0.9	0.7	0.7
Wisconsin	0.7	0.7	1.1	0.7	0.6	0.7
New York	0.6	0.6	0.6	0.7	0.6	0.6
Arizona	0.6	0.6	1.3	0.6	0.6	0.6
District of Columbia	0.9	0.6	0.7	0.8	0.6	0.5

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 Major Event Days. In 2018, Michigan ranked 8th worst in CAIDI with Major Event Days and 2nd worst without Major Event Days.

Figure 11 shows no significant improvement in Michigan's CAIDI with Major Event Days and Figure 12 shows modest improvement in Michigan's CAIDI without Major Event Days, suggesting marginal improvements in system reliability in the course of "normal" business conditions, but a persistent susceptibility to extreme or unplanned events.

Figure 9: 2018 CAIDI with MED

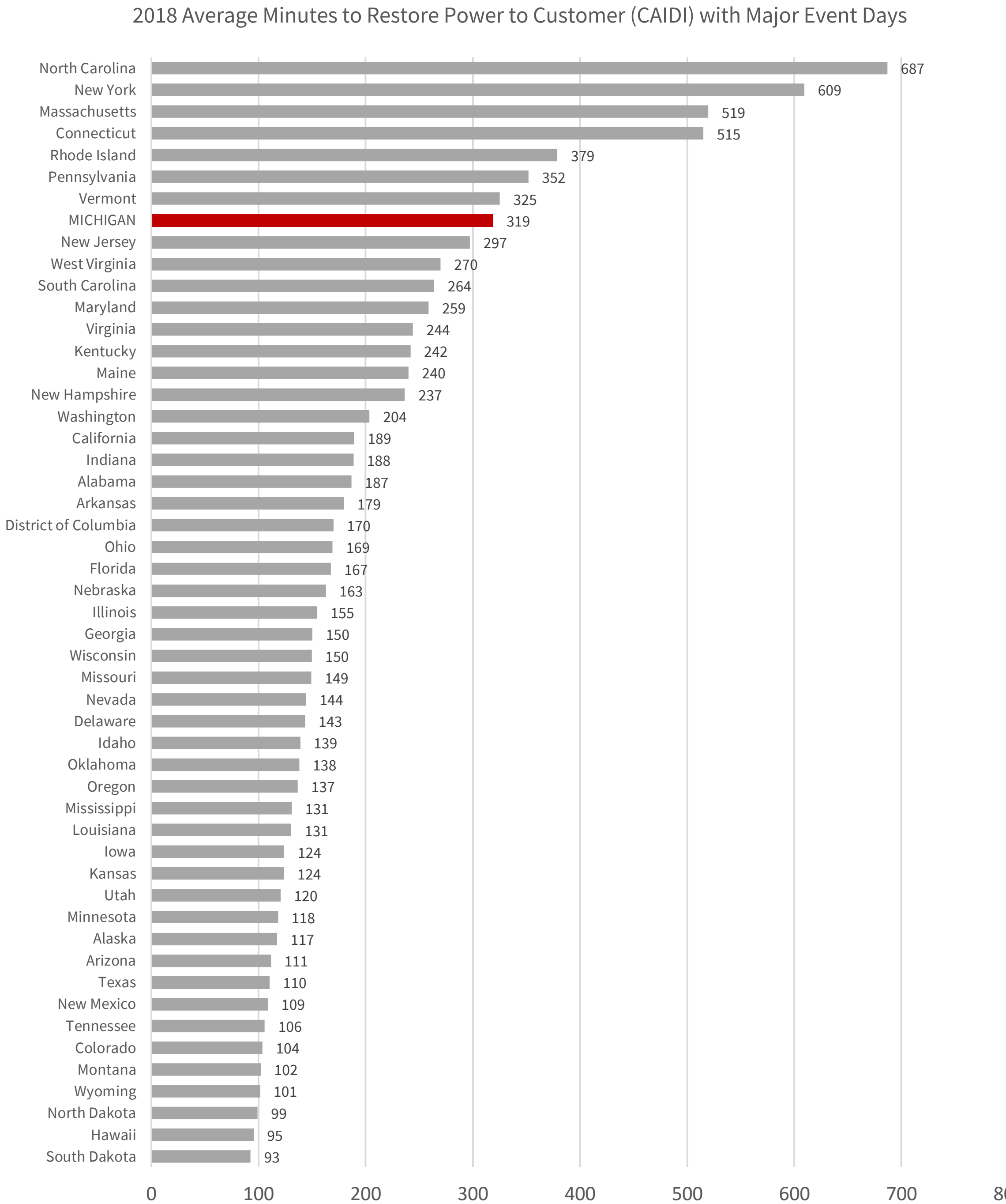


Figure 10: 2018 CAIDI without MED

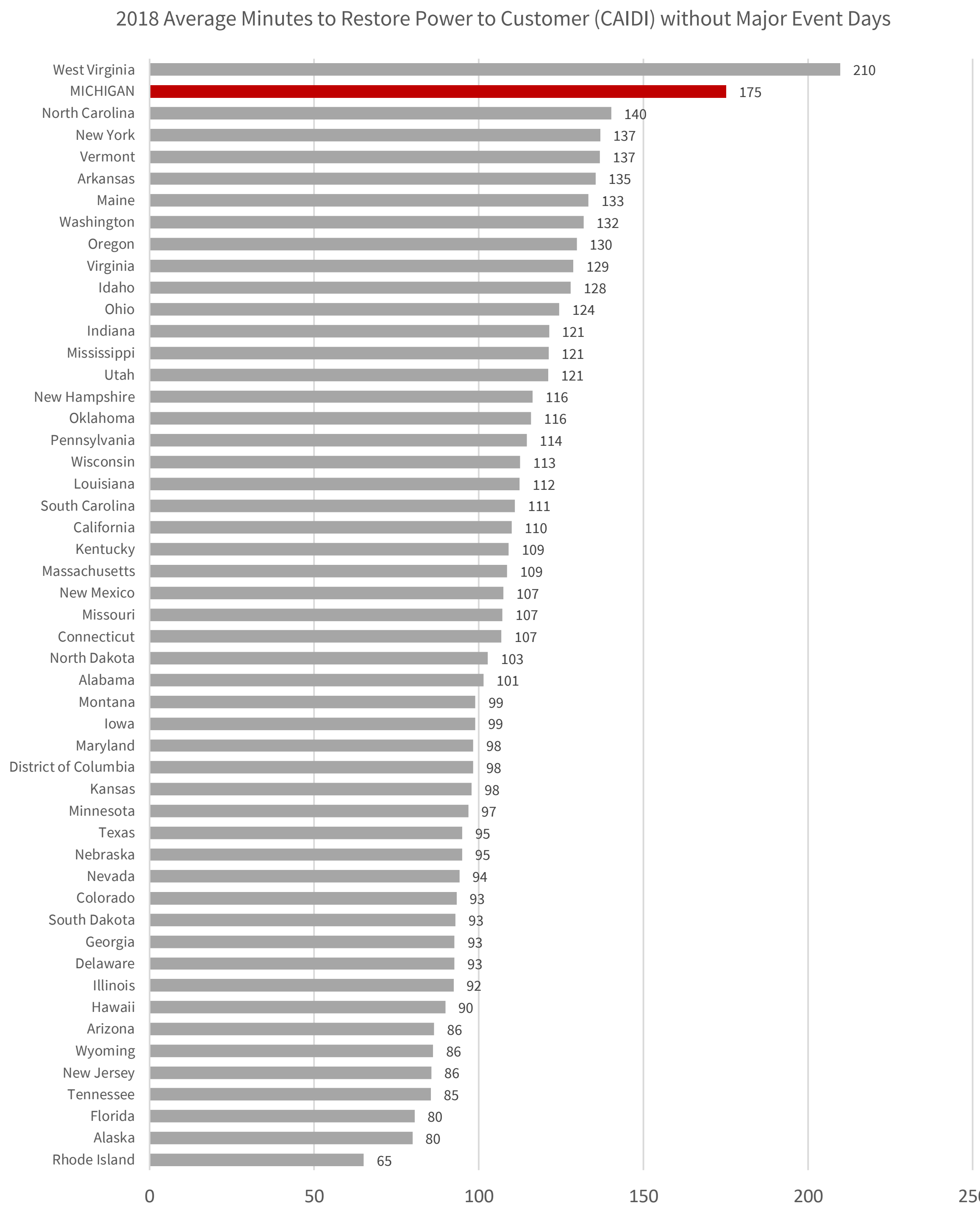


Figure 11: CAIDI with MED

Average Minutes to Restore Power to Customer (CAIDI) with Major Event Days						
State	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
North Carolina	171	509	202	364	189	687
New York	147	138	155	145	229	609
Massachusetts	371	125	111	145	248	519
Connecticut	115	117	149	169	298	515
Rhode Island	622	71	278	140	615	379
Pennsylvania	140	294	157	117	153	352
Vermont	3	333	117	183	347	325
MICHIGAN	511	450	296	234	559	319
New Jersey	125	115	183	109	87	297
West Virginia	232	279	321	300	280	270
South Carolina	110	295	205	1183	217	264
Maryland	94	187	114	110	115	259
Virginia	256	123	138	148	137	244
Kentucky	107	127	123	123	133	242
Maine	5	114	43	194	861	240
New Hampshire	95	376	95	125	475	237
Washington	143	189	300	175	191	204
California	116	110	125	115	173	189
Indiana	192	283	289	319	161	188
Alabama	163	132	120	109	158	187
Arkansas	160	150	158	198	189	179
District of Columbia	141	139	164	140	104	170
Ohio	184	138	137	141	184	169
Florida	78	81	77	254	1157	167
Nebraska	168	198	204	218	161	163
Illinois	237	181	152	151	128	155
Georgia	102	135	137	245	442	150
Wisconsin	200	170	102	151	200	150
Missouri	265	130	156	183	215	149
Nevada	110	94	122	104	125	144
Delaware	110	127	128	115	145	143
Idaho	137	128	178	138	150	139
Oklahoma	443	221	869	205	189	138
Oregon	237	208	195	271	245	137
Mississippi	105	85	147	135	210	131
Louisiana	91	71	146	178	161	131
Iowa	130	137	98	110	117	124
Kansas	162	104	163	116	209	124
Utah	133	136	142	149	126	120
Minnesota	320	115	162	201	151	118
Alaska	151	111	207	83	104	117
Arizona	87	103	289	99	98	111
Texas	120	120	166	122	236	110
New Mexico	142	89	113	86	96	109
Tennessee	85	177	108	109	255	106
Colorado	270	87	104	128	138	104
Montana	121	120	172	117	125	102
Wyoming	186	132	125	124	110	101
North Dakota	146	112	101	109	94	99
Hawaii	79	91	89	74	115	95
South Dakota	566	167	635	243	94	93

Figure 12: CAIDI without MED

Average Minutes to Restore Power to Customer (CAIDI) without Major Event Days						
State	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West Virginia	234	204	204	201	211	210
MICHIGAN	222	207	185	192	181	175
North Carolina	109	320	164	127	127	140
New York	105	120	148	129	134	137
Vermont	1	139	117	149	129	137
Arkansas	128	159	122	123	121	135
Maine	2	29	39	119	110	133
Washington	119	120	127	133	138	132
Oregon	125	124	142	136	141	130
Virginia	106	109	113	118	117	129
Idaho	113	116	135	137	140	128
Ohio	114	119	121	119	122	124
Indiana	108	207	118	154	123	121
Mississippi	88	98	111	105	109	121
Utah	138	124	128	110	120	121
New Hampshire	114	89	87	102	103	116
Oklahoma	116	225	301	121	125	116
Pennsylvania	109	108	108	104	116	114
Wisconsin	123	106	79	112	121	113
Louisiana	79	82	87	101	107	112
South Carolina	100	89	132	132	102	111
California	106	102	112	109	111	110
Kentucky	94	95	90	103	101	109
Massachusetts	93	100	102	124	501	109
New Mexico	103	88	107	89	98	107
Missouri	112	121	128	106	115	107
Connecticut	105	117	107	108	100	107
North Dakota	92	79	94	92	77	103
Alabama	97	107	96	98	108	101
Montana	111	107	97	107	114	99
Iowa	99	96	92	98	104	99
Maryland	93	86	104	103	100	98
District of Columbia	141	128	164	140	104	98
Kansas	89	89	96	104	99	98
Minnesota	112	88	97	103	98	97
Texas	80	89	111	97	97	95
Nebraska	123	137	149	174	98	95
Nevada	90	89	93	94	99	94
Colorado	219	83	90	88	88	93
South Dakota	157	331	577	105	83	93
Georgia	75	76	80	86	95	93
Delaware	101	100	90	94	88	93
Illinois	147	99	103	120	95	92
Hawaii	80	67	70	78	86	90
Arizona	122	91	83	95	98	86
Wyoming	101	120	116	96	102	86
New Jersey	102	85	74	82	77	86
Tennessee	70	150	80	93	104	85
Florida	78	91	75	79	79	80
Alaska	100	106	95	88	81	80
Rhode Island	80	71	69	71	76	65

AFFORDABILITY METRICS

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 of electricity are common billing determinants. The ways in which utilities assign costs to these various components of the bill vary greatly among utilities, among 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 generally the best way to compare utility costs.

The Energy Information Administration of the US Department of Energy 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 "other" with almost all electricity delivered in most states going to the first three classes. EIA makes these data available through an Electric Data Browser on its web site, at http://www.eia.gov/electricity/data/browser/. 2018 is the most recent complete calendar year available and is used here for comparison of the cost of electricity in the various states, reported in cents per kWh.

Michigan's electricity rates are summarized in the following table.

2018 Metric	Value	Michigan's Rank
Residential electricity cost per kWh	15.5 cents	11th highest
Commercial electricity cost per kWh	11.2 cents	14th highest
Industrial electricity cost per kWh	7.1 cents	24th highest
All sectors electricity cost per kWh	11.4 cents	14th highest

Expenditures

Electricity is one of the essentials of modern life, and so the cost of electricity matters both to households who must choose between electricity consumption and other goods and services and to competitive industry.

The affordability of electricity is a nuanced matter. For households, 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 the context of income. Comparison of total household energy expenses and total household energy expenses as a share of household income are common measures of affordability.

Commercial and industrial users of electricity are less affected by climate and 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; rates comparison is more useful and is addressed later in this report.

Below, we first examine household energy expenditures, then look at electricity rates for residential, commercial, and industrial customers.

The prices of electricity and heating fuels are far from the only determining factor for overall energy affordability. For example, whereas households in warmer climates may consume more electricity than households in colder climates on an annual basis to run air conditioning units, those same households will not spend as much on natural gas, propane, or other heating fuels during the winter. Energy expenditures are measured by the EIA in the State Energy Data System (SEDS) database at https://www.eia.gov/state/seds/. The following graph shows residential electricity and non-electricity energy expenditures per household by state.

Figure 15 shows, despite its high electricity rates, Michigan had the 36th highest electricity expenditure per household and Figure 16 shows Michigan had the 10th highest non-electricity energy expenditure per household. Although electricity expenditure is low, non-electricity expenditure is higher than average across all states, bringing Michigan's average total energy expenditure per household closer to 17th highest. This can be seen in Figure 17, showing electricity and non-electricity expenditures on the same graph, sorted by total expenditure. Michigan residents pay the most per household relative to its peer states. At 3.3%, Michigan had the 5th highest average residential household expenditure growth rate over the last ten years, placing it highest among its peer group of states (as seen in Figure 15).

Figure 18 shows total household energy expenditures in Michigan account for 3.5% of median household income, making Michigan the 15th highest state in the country and the highest among its peer group of states.

2018 Metric	Value	Michigan Rank
Average Household Electricity Expenditure	$1,243 per year	36th highest
Average Household Non-Electricity Energy Expenditure	$863 per year	10th highest
Average Total Household Energy Expenditure	$2,106	17th highest
Total Household Energy Expenditure as a % of Median Household Income	3.5%	15th highest

Figure 13: Summary of Residential Expenditures and Reliability

State	Residential Electricity Sales per Customer (kWh)	Residential Electricity Price ($/kWh)	Residential Average Monthly Bill	SAIDI with MED	SAIDI without MED	SAIFI with MED	SAIFI without MED	CAIDI with MED	CAIDI without MED
Hawaii	6,213	$0.32	$168	191	152	2.0	1.7	95	90
Connecticut	8,686	$0.21	$153	656	76	1.3	0.7	515	107
Alabama	14,838	$0.12	$151	308	121	1.5	1.2	187	101
South Carolina	13,908	$0.12	$144	470	137	1.7	1.2	264	111
Mississippi	14,966	$0.11	$139	268	212	1.8	1.6	131	121
Tennessee	15,394	$0.11	$137	200	139	1.9	1.7	106	85
Virginia	13,977	$0.12	$137	507	188	1.8	1.4	244	129
Maryland	12,064	$0.13	$134	337	95	1.3	1.0	259	98
Texas	14,106	$0.11	$132	167	114	1.4	1.1	110	95
Arizona	12,342	$0.13	$131	115	61	0.9	0.6	111	86
Massachusetts	7,286	$0.22	$131	813	99	1.6	0.9	519	109
Georgia	13,709	$0.11	$131	373	123	1.6	1.3	150	93
Florida	13,321	$0.12	$ 128	310	77	1.1	1.0	167	80
Missouri	13,416	$0.11	$127	150	94	1.0	0.8	149	107
West Virginia	13,596	$0.11	$127	740	513	2.6	2.4	270	210
Alaska	6,869	$0.22	$126	335	193	3.1	2.6	117	80
North Carolina	13,542	$0.11	$125	1762	162	2.2	1.2	687	140
Kansas	11,206	$0.13	$125	155	109	1.2	1.0	124	98
Kentucky	13,995	$0.11	$124	406	147	1.8	1.3	242	109
Indiana	12,075	$0.12	$123	286	142	1.5	1.1	188	121
Louisiana	15,379	$0.10	$123	276	206	2.1	1.8	131	112
Delaware	11,724	$0.13	$122	136	74	1.0	0.9	143	93
New Hampshire	7,453	$0.20	$122	509	152	2.2	1.3	237	116
South Dakota	12,541	$0.12	$121	92	74	1.1	0.9	93	93
Rhode Island	7,068	$0.21	$121	595	65	1.6	1.0	379	65
Pennsylvania	10,370	$0.14	$120	518	119	1.4	1.0	352	114
Oklahoma	13,664	$0.10	$117	176	127	1.3	1.1	138	116
Ohio	10,967	$0.13	$115	242	151	1.4	1.2	169	124
North Dakota	13,417	$0.10	$115	94	95	0.9	0.9	99	103
Arkansas	13,872	$0.10	$113	323	210	1.8	1.5	179	135
Nevada	11,363	$0.12	$112	126	77	1.0	0.8	144	94
New York	7,253	$0.19	$112	406	79	1.0	0.6	609	137
Nebraska	12,251	$0.11	$109	188	74	1.1	0.7	163	95
Iowa	10,709	$0.12	$109	127	93	1.0	0.9	124	99
New Jersey	8,276	$0.15	$106	510	88	1.4	1.0	297	86
MICHIGAN	8,047	$0.15	$104	443	185	1.4	1.1	319	175
Minnesota	9,436	$0.13	$103	127	87	1.0	0.9	118	97
California	6,556	$0.19	$103	195	102	1.0	0.9	189	110
District of Columbia	9,440	$0.13	$101	109	53	0.6	0.5	170	98
Vermont	6,715	$0.18	$101	898	262	2.6	1.9	325	137
Oregon	10,816	$0.11	$99	113	93	0.9	0.8	137	130
Wisconsin	8,311	$0.14	$97	123	79	0.8	0.7	150	113
Maine	6,863	$0.17	$96	665	273	2.8	2.0	240	133
Idaho	11,334	$0.10	$96	174	145	1.2	1.1	139	128
Illinois	8,928	$0.13	$95	143	73	0.9	0.8	155	92
Wyoming	10,088	$0.11	$95	135	118	1.3	1.2	101	86
Washington	11,485	$0.10	$93	270	115	1.2	0.8	204	132
Montana	10,201	$0.11	$93	143	118	1.3	1.2	102	99
Colorado	8,288	$0.12	$84	113	85	1.0	0.9	104	93
New Mexico	7,672	$0.13	$81	138	123	1.1	1.1	109	107
Utah	8,903	$0.10	$77	125	127	1.0	1.0	120	121

Figure 14: 2018 Average Annual Household Electricity Expenditure

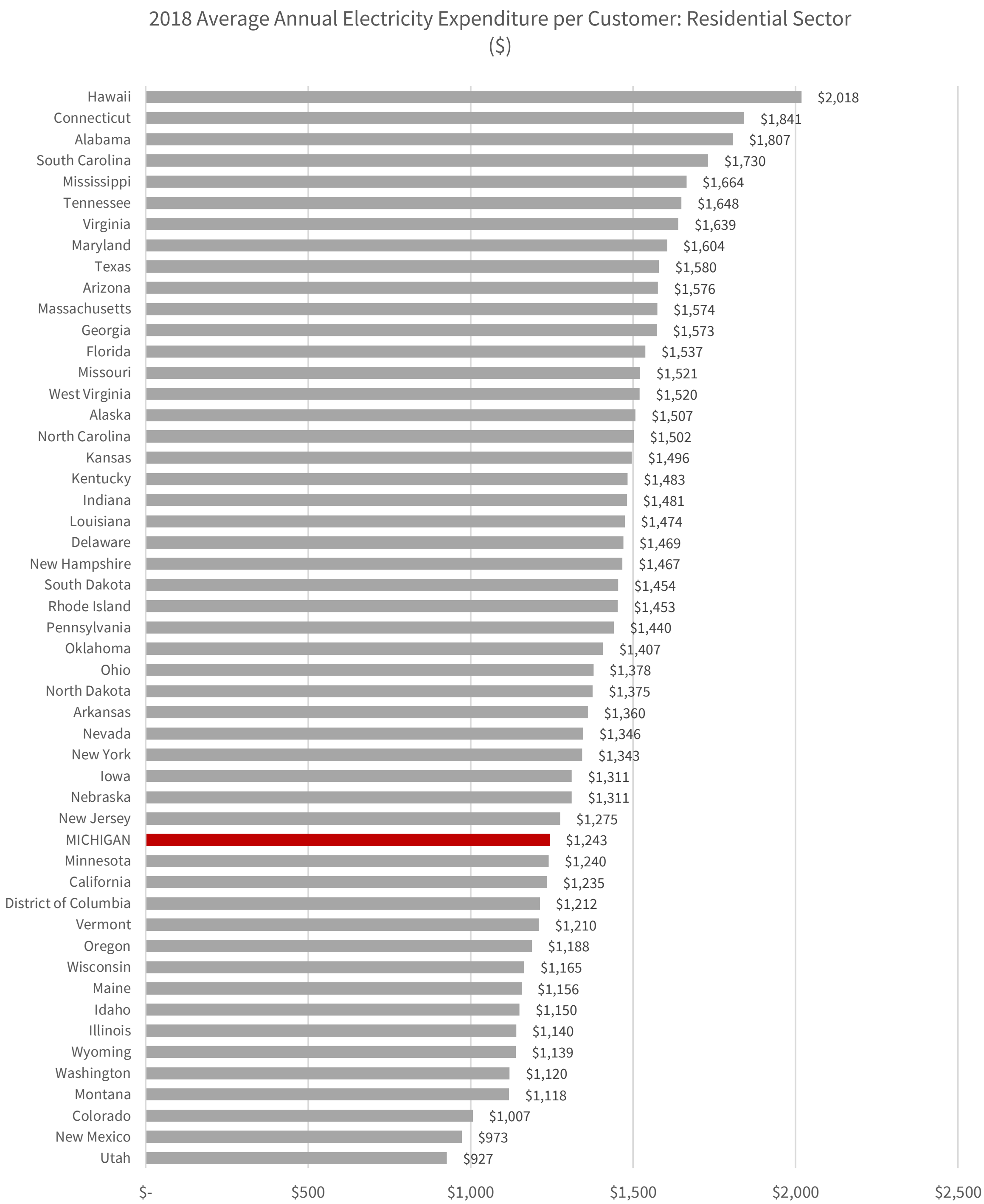


Figure 15: Average Annual Household Electricity Expenditure

Average Annual Electricity Expenditure per Customer: Residential Sector ($)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Hawaii	$1,791	$2,026	$2,433	$2,438	$2,284	$2,251	$1,825	$1,665	$1,792	$2,018	1%
Connecticut	$1,767	$1,732	$1,609	$1,521	$1,585	$1,729	$1,838	$1,706	$1,680	$1,841	0%
Alabama	$1,577	$1,772	$1,709	$1,623	$1,636	$1,743	$1,710	$1,747	$1,711	$1,807	1%
South Carolina	$1,482	$1,651	$1,620	$1,580	$1,618	$1,773	$1,729	$1,753	$1,690	$1,730	2%
Mississippi	$1,488	$1,593	$1,571	$1,470	$1,578	$1,695	$1,647	$1,511	$1,505	$1,664	1%
Tennessee	$1,394	$1,543	$1,587	$1,476	$1,491	$1,593	$1,542	$1,547	$1,480	$1,648	2%
Virginia	$1,489	$1,553	$1,510	$1,485	$1,504	$1,560	$1,567	$1,526	$1,494	$1,639	1%
Maryland	$1,845	$1,883	$1,646	$1,548	$1,640	$1,676	$1,679	$1,698	$1,574	$1,604	-1%
Texas	$1,693	$1,668	$1,678	$1,539	$1,600	$1,649	$1,632	$1,525	$1,470	$1,580	-1%
Arizona	$1,385	$1,393	$1,423	$1,438	$1,474	$1,446	$1,496	$1,502	$1,541	$1,576	1%
Massachusetts	$1,234	$1,168	$1,115	$1,122	$1,212	$1,283	$1,431	$1,365	$1,402	$1,574	2%
Georgia	$1,376	$1,529	$1,574	$1,473	$1,496	$1,610	$1,554	$1,570	$1,517	$1,573	1%
Florida	$1,684	$1,639	$1,561	$1,481	$1,458	$1,558	$1,586	$1,480	$1,517	$1,537	-1%
Missouri	$1,088	$1,256	$1,301	$1,294	$1,382	$1,398	$1,390	$1,400	$1,387	$1,521	3%
West Virginia	$1,058	$1,261	$1,271	$1,274	$1,277	$1,298	$1,339	$1,513	$1,432	$1,520	4%
Alaska	$1,346	$1,251	$1,373	$1,403	$1,375	$1,390	$1,436	$1,438	$1,534	$1,507	1%
North Carolina	$1,348	$1,502	$1,417	$1,409	$1,446	$1,513	$1,506	$1,457	$1,368	$1,502	1%
Kansas	$1,036	$1,185	$1,256	$1,274	$1,294	$1,355	$1,327	$1,408	$1,376	$1,496	4%
Kentucky	$1,155	$1,293	$1,298	$1,279	$1,355	$1,436	$1,377	$1,412	$1,370	$1,483	3%
Indiana	$1,132	$1,222	$1,242	$1,259	$1,325	$1,387	$1,338	$1,380	$1,368	$1,481	3%
Louisiana	$1,238	$1,488	$1,450	$1,260	$1,440	$1,483	$1,440	$1,390	$1,386	$1,474	2%
Delaware	$1,549	$1,659	$1,594	$1,535	$1,467	$1,515	$1,574	$1,524	$1,461	$1,469	-1%
New Hampshire	$1,226	$1,225	$1,227	$1,186	$1,232	$1,303	$1,379	$1,331	$1,379	$1,467	2%
South Dakota	$1,043	$1,121	$1,161	$1,184	$1,299	$1,313	$1,304	$1,350	$1,381	$1,454	3%
Rhode Island	$1,060	$1,153	$1,037	$1,033	$1,098	$1,201	$1,374	$1,308	$1,269	$1,453	3%
Pennsylvania	$1,177	$1,338	$1,384	$1,281	$1,316	$1,365	$1,399	$1,400	$1,374	$1,440	2%
Oklahoma	$1,118	$1,303	$1,387	$1,291	$1,326	$1,370	$1,330	$1,338	$1,323	$1,407	2%
Ohio	$1,124	$1,263	$1,258	$1,263	$1,285	$1,351	$1,347	$1,334	$1,274	$1,378	2%
North Dakota	$1,046	$1,094	$1,182	$1,186	$1,318	$1,361	$1,259	$1,275	$1,313	$1,375	3%
Arkansas	$1,181	$1,287	$1,275	$1,250	$1,304	$1,304	$1,323	$1,289	$1,268	$1,360	1%
Nevada	$1,448	$1,356	$1,249	$1,327	$1,319	$1,388	$1,398	$1,266	$1,228	$1,346	-1%
New York	$1,221	$1,373	$1,339	$1,274	$1,358	$1,424	$1,336	$1,255	$1,239	$1,343	1%
Iowa	$1,035	$1,142	$1,127	$1,134	$1,204	$1,194	$1,182	$1,238	$1,231	$1,311	2%
Nebraska	$1,026	$1,128	$1,151	$1,206	$1,280	$1,276	$1,223	$1,266	$1,259	$1,311	2%
New Jersey	$1,323	$1,454	$1,380	$1,309	$1,297	$1,268	$1,320	$1,303	$1,229	$1,275	0%
MICHIGAN	$896	$1,018	$1,088	$1,146	$1,163	$1,134	$1,123	$1,220	$1,169	$1,243	3%
Minnesota	$966	$1,034	$1,070	$1,081	$1,158	$1,167	$1,108	$1,161	$1,171	$1,240	3%
California	$1,025	$994	$1,004	$1,055	$1,092	$1,095	$1,135	$1,142	$1,218	$1,235	2%
District of Columbia	$1,176	$1,307	$1,204	$1,062	$1,086	$1,103	$1,311	$1,185	$1,158	$1,212	0%
Vermont	$1,030	$1,077	$1,118	$1,153	$1,170	$1,192	$1,144	$1,144	$1,140	$1,210	2%
Oregon	$1,059	$1,026	$1,134	$1,126	$1,159	$1,168	$1,155	$1,161	$1,239	$1,188	1%
Wisconsin	$987	$1,087	$1,109	$1,114	$1,143	$1,139	$1,131	$1,153	$1,136	$1,165	2%
Maine	$978	$982	$961	$933	$950	$1,007	$1,041	$1,038	$1,046	$1,156	2%
Idaho	$1,011	$977	$990	$1,050	$1,180	$1,146	$1,140	$1,139	$1,205	$1,150	1%
Illinois	$985	$1,104	$1,090	$1,046	$962	$1,065	$1,079	$1,102	$1,076	$1,140	1%
Wyoming	$913	$929	$987	$1,024	$1,090	$1,087	$1,094	$1,136	$1,165	$1,139	2%
Washington	$1,004	$993	$1,061	$1,062	$1,087	$1,046	$1,052	$1,087	$1,185	$1,120	1%
Montana	$918	$928	$1,020	$1,019	$1,066	$1,043	$1,068	$1,067	$1,137	$1,118	2%
Colorado	$824	$939	$961	$971	$1,019	$1,005	$1,001	$1,006	$990	$1,007	2%
New Mexico	$772	$832	$883	$895	$919	$934	$951	$912	$950	$973	2%
Utah	$794	$821	$847	$944	$994	$954	$971	$991	$980	$927	2%

Figure 16: 2018 Average Annual Household Non-Electricity Energy Expenditures

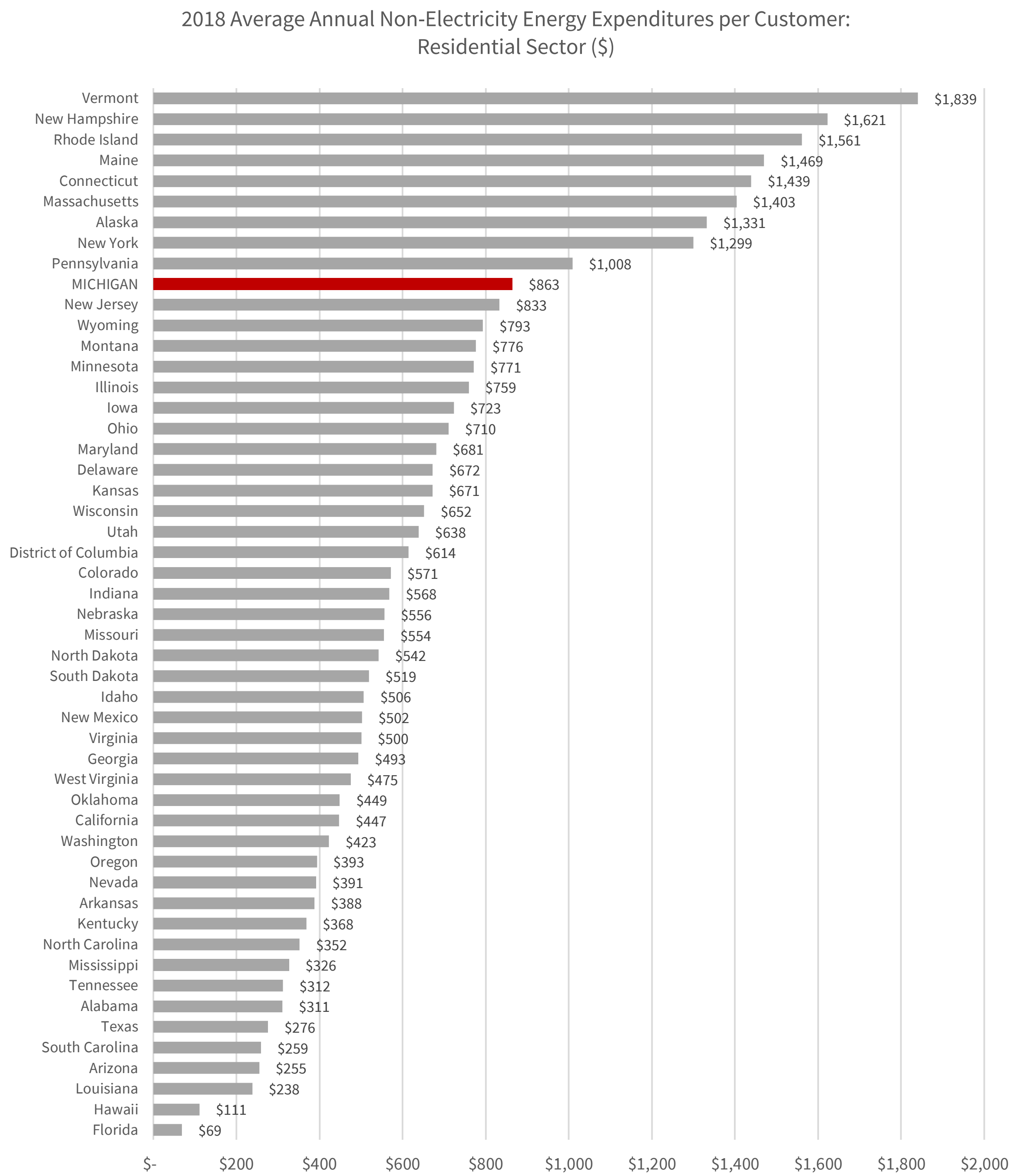


Figure 17: 2018 Energy Expenditures per Household

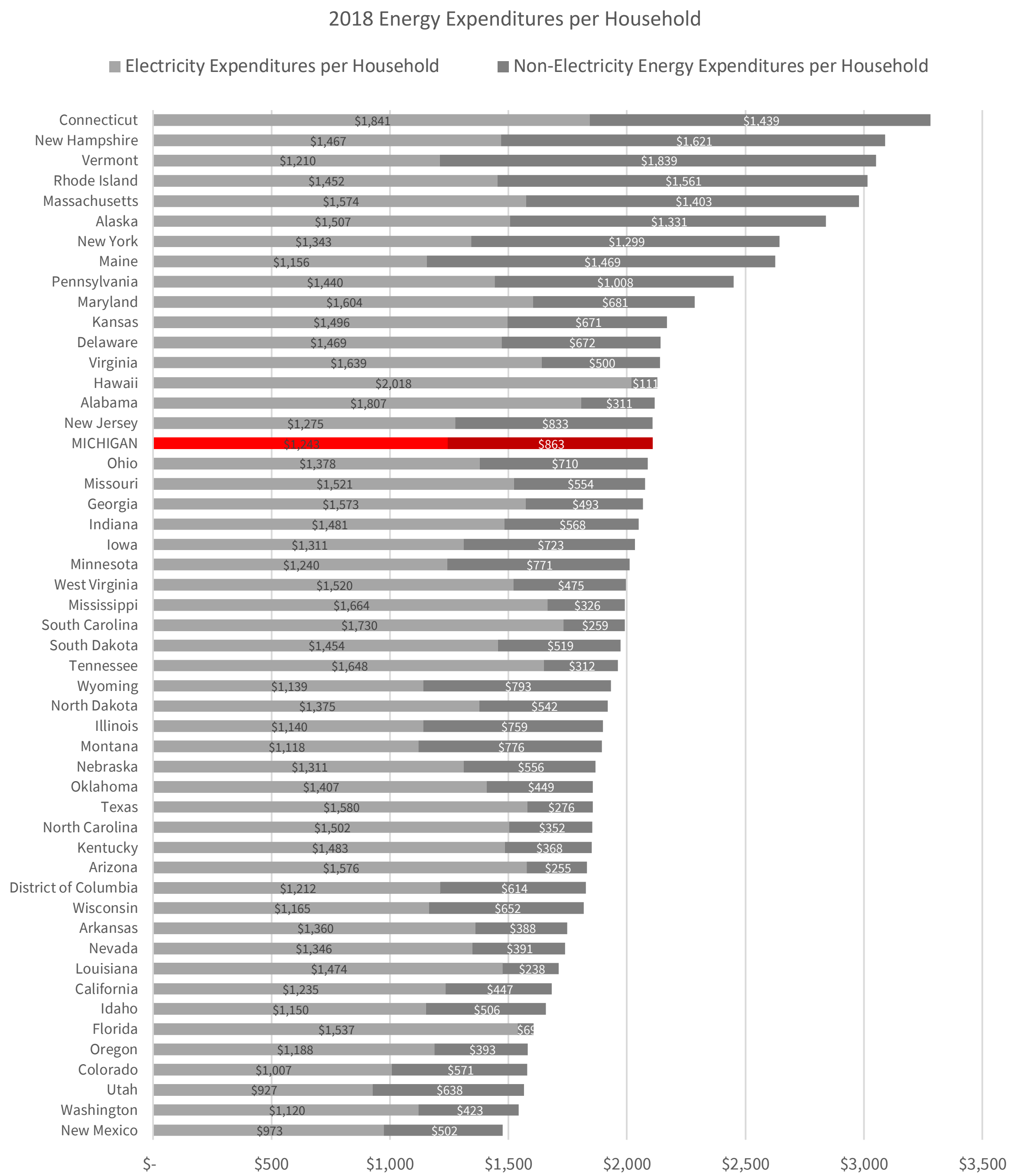
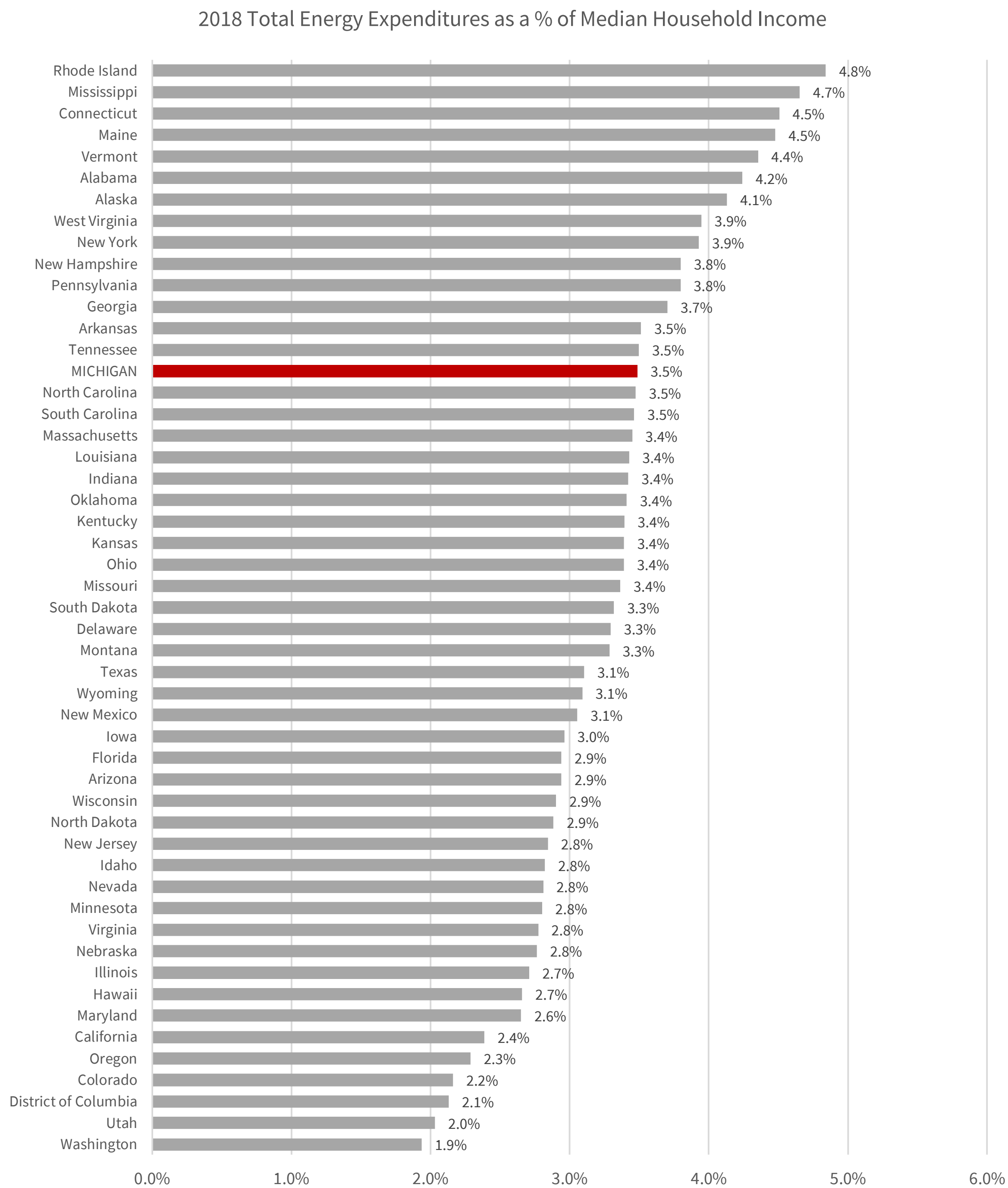


Figure 18: 2018 Total Energy Expenditure as a % of Household Income



Residential Sector Electricity Rates

Although affordability is the most important measure of household energy costs, residential electricity rates are also worth comparing across states.

As shown in Figure 19, Michigan's 15.5 cents per kilowatt-hour price of electricity for the residential sector is 11th highest relative to all other states, and highest relative to its neighbors. Figure 20 shows that Michigan's electricity price for residential customers has increased at an average compound annual growth rate of nearly 3.3%. This is the 6th highest overall rate of growth in residential rates and the highest among its peer group.

Figure 19: 2018 Residential Electricity Price

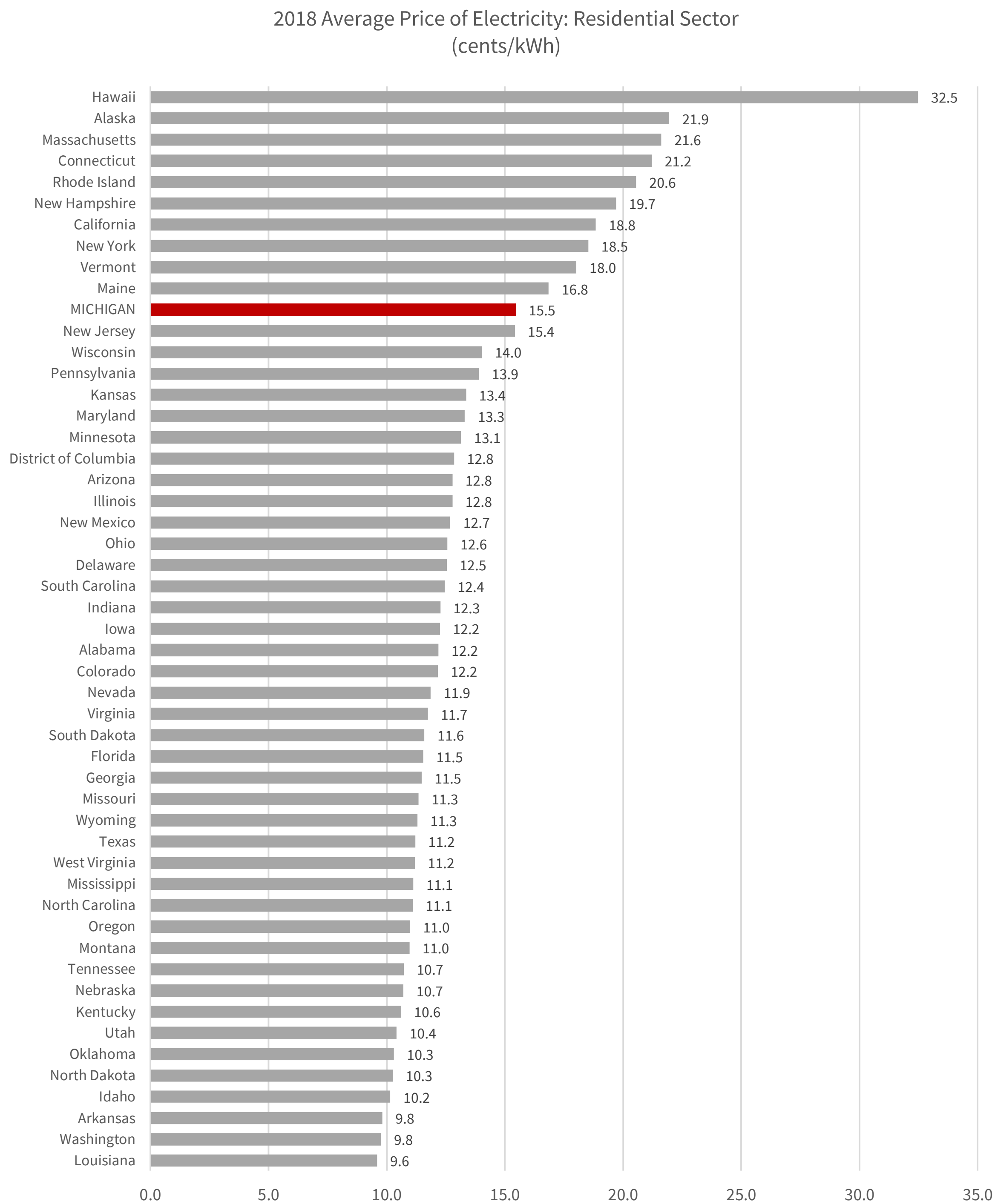


Figure 20: Residential Electricity Price

Average Price of Electricity: Residential Sector (cents/kWh)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Hawaii	24.2	28.1	34.7	37.3	37.0	37.0	29.6	27.5	29.5	32.5	3%
Alaska	17.1	16.3	17.6	17.9	18.1	19.1	19.8	20.3	21.3	21.9	2%
Massachusetts	16.9	14.6	14.7	14.9	15.8	17.4	19.8	19.0	20.1	21.6	3%
Connecticut	20.3	19.3	18.1	17.3	17.6	19.8	20.9	20.0	20.3	21.2	0%
Rhode Island	15.6	15.9	14.3	14.4	15.2	17.2	19.3	18.6	18.3	20.6	3%
New Hampshire	16.4	16.3	16.5	16.1	16.3	17.5	18.5	18.4	19.2	19.7	2%
California	14.7	14.8	14.8	15.3	16.2	16.3	17.0	17.4	18.3	18.8	2%
New York	17.5	18.7	18.3	17.6	18.8	20.1	18.5	17.6	18.0	18.5	1%
Vermont	14.9	15.6	16.3	17.0	17.1	17.5	17.1	17.4	17.7	18.0	2%
Maine	15.6	15.7	15.4	14.7	14.4	15.3	15.6	15.8	16.0	16.8	1%
MICHIGAN	11.6	12.5	13.3	14.1	14.6	14.5	14.4	15.2	15.4	15.5	3%
New Jersey	16.3	16.6	16.2	15.8	15.7	15.8	15.8	15.7	15.7	15.4	-1%
Wisconsin	11.9	12.7	13.0	13.2	13.6	13.7	14.1	14.1	14.4	14.0	2%
Pennsylvania	11.7	12.7	13.3	12.8	12.8	13.3	13.6	13.9	14.2	13.9	2%
Kansas	9.5	10.0	10.7	11.2	11.6	12.2	12.3	13.1	13.3	13.4	3%
Maryland	15.0	14.3	13.3	12.8	13.3	13.6	13.8	14.2	14.0	13.3	-1%
Minnesota	10.0	10.6	11.0	11.4	11.8	12.0	12.1	12.7	13.0	13.1	3%
District of Columbia	13.7	14.0	13.4	12.3	12.6	12.7	13.0	12.3	12.9	12.8	-1%
Arizona	10.7	11.0	11.1	11.3	11.7	11.9	12.1	12.2	12.4	12.8	2%
Illinois	11.3	11.5	11.8	11.4	10.6	11.9	12.5	12.5	13.0	12.8	1%
New Mexico	10.0	10.5	11.0	11.4	11.7	12.3	12.5	12.0	12.9	12.7	2%
Ohio	10.7	11.3	11.4	11.8	12.0	12.5	12.8	12.5	12.6	12.6	2%
Delaware	14.1	13.8	13.7	13.6	13.0	13.3	13.4	13.4	13.4	12.5	-1%
South Carolina	10.4	10.5	11.1	11.8	12.0	12.5	12.6	12.7	13.0	12.4	2%
Indiana	9.5	9.6	10.1	10.5	11.0	11.5	11.6	11.8	12.3	12.3	3%
Iowa	10.0	10.4	10.5	10.8	11.0	11.2	11.6	11.9	12.3	12.2	2%
Alabama	10.7	10.7	11.1	11.4	11.3	11.5	11.7	12.0	12.6	12.2	1%
Colorado	10.0	11.0	11.3	11.5	11.9	12.2	12.1	12.1	12.2	12.2	2%
Nevada	12.9	12.4	11.6	11.8	11.9	12.9	12.8	11.4	12.0	11.9	-1%
Virginia	10.6	10.5	10.6	11.1	10.8	11.1	11.4	11.4	11.6	11.7	1%
South Dakota	8.5	9.0	9.4	10.1	10.3	10.5	11.1	11.5	11.8	11.6	3%
Florida	12.4	11.4	11.5	11.4	11.3	11.9	11.6	11.0	11.6	11.5	-1%
Georgia	10.1	10.1	11.1	11.2	11.5	11.7	11.5	11.5	11.9	11.5	1%
Missouri	8.5	9.1	9.8	10.2	10.6	10.6	11.2	11.2	11.6	11.3	3%
Wyoming	8.6	8.8	9.1	9.9	10.2	10.5	11.0	11.1	11.4	11.3	3%
Texas	12.4	11.6	11.1	11.0	11.4	11.9	11.6	11.0	11.0	11.2	-1%
West Virginia	7.9	8.8	9.4	9.9	9.5	9.3	10.1	11.4	11.6	11.2	4%
Mississippi	10.2	9.9	10.2	10.3	10.8	11.3	11.3	10.5	11.1	11.1	1%
North Carolina	10.0	10.1	10.3	10.9	11.0	11.1	11.3	11.0	10.9	11.1	1%
Oregon	8.7	8.9	9.5	9.8	9.9	10.5	10.7	10.7	10.7	11.0	2%
Montana	8.9	9.2	9.8	10.1	10.3	10.2	10.9	10.9	11.0	11.0	2%
Tennessee	9.3	9.2	10.0	10.1	10.0	10.3	10.3	10.4	10.7	10.7	1%
Nebraska	8.5	8.9	9.3	10.0	10.3	10.4	10.6	10.8	11.0	10.7	2%
Kentucky	8.4	8.6	9.2	9.4	9.8	10.2	10.2	10.5	10.9	10.6	2%
Utah	8.5	8.7	9.0	9.9	10.4	10.7	10.9	11.0	11.0	10.4	2%
Oklahoma	8.5	9.1	9.5	9.5	9.7	10.0	10.1	10.2	10.6	10.3	2%
North Dakota	7.6	8.1	8.6	9.1	9.1	9.2	9.6	10.2	10.3	10.3	3%
Idaho	7.8	8.0	7.9	8.7	9.3	9.7	9.9	10.0	10.0	10.2	3%
Arkansas	9.1	8.9	9.0	9.3	9.6	9.5	9.8	9.9	10.3	9.8	1%
Washington	7.7	8.0	8.3	8.5	8.7	8.7	9.1	9.5	9.7	9.8	2%
Louisiana	8.1	9.0	9.0	8.4	9.4	9.6	9.3	9.3	9.7	9.6	2%

Commercial Sector Electricity Rates

As shown in Figure 21, Michigan's 11.2 cents per kilowatt-hour price of electricity for the commercial sector is relatively high compared to other states, ranking 14th highest.

Figure 22 shows that Michigan's electricity price for commercial customers has remained flat over the past five years but is the highest among its peer group states. The average compound annual growth rate of Michigan's commercial electricity price from 2009-2018 was approximately 2%.

Figure 21: 2018 Commercial Electricity Price

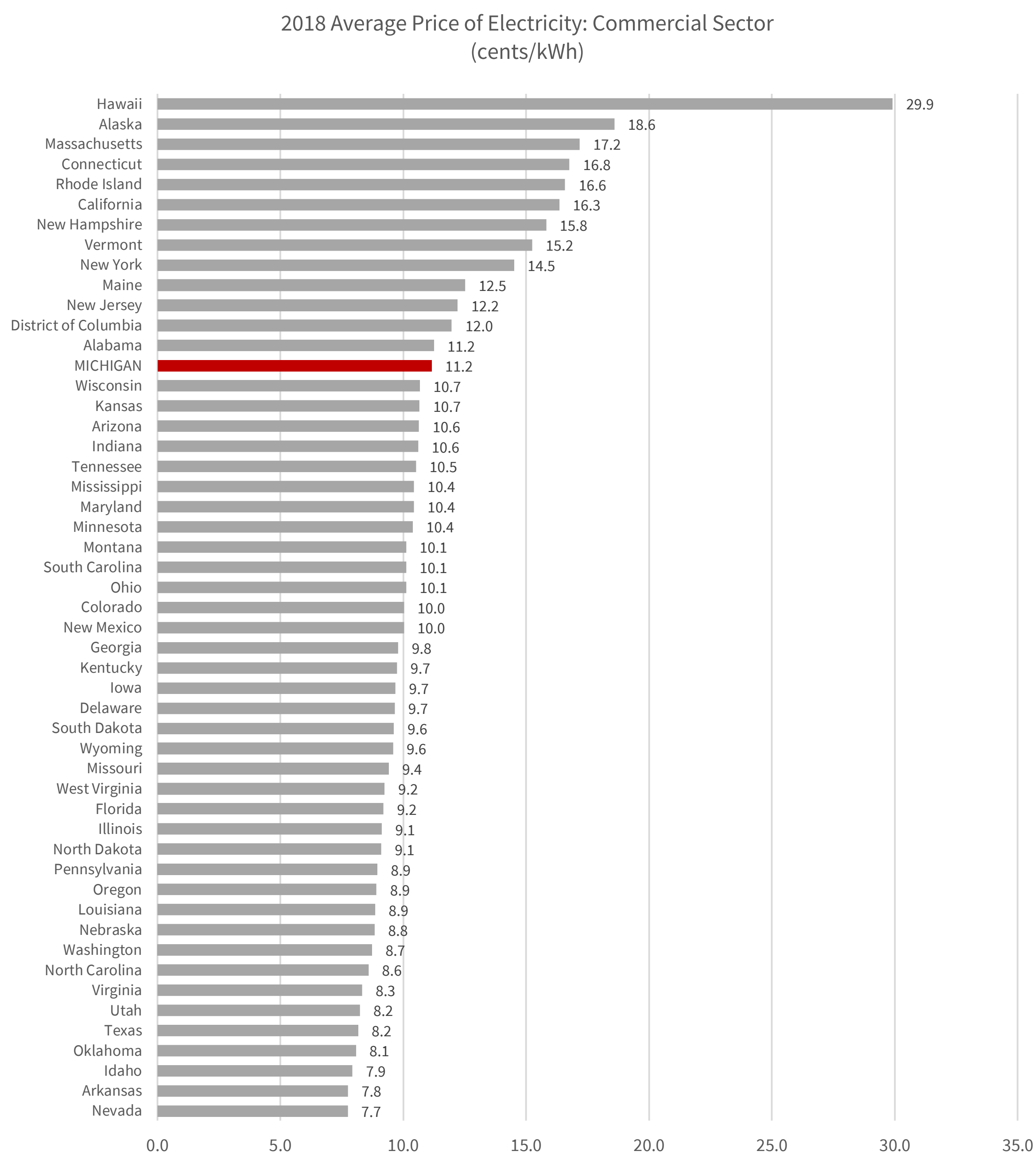


Figure 22: Commercial Electricity Price

Average Price of Electricity: Commercial Sector (cents/kWh)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Hawaii	21.9	25.9	32.4	34.9	34.1	34.2	26.9	24.6	26.8	29.9	3%
Alaska	14.5	14.0	15.1	14.9	15.6	17.1	17.4	17.6	18.9	18.6	3%
Massachusetts	15.4	14.5	14.3	13.8	14.2	14.7	15.8	15.6	15.9	17.2	1%
Connecticut	16.9	16.5	15.6	14.7	14.6	15.6	16.0	15.8	16.1	16.8	0%
Rhode Island	13.7	13.1	12.4	11.9	12.9	14.6	15.8	14.9	15.2	16.6	2%
California	13.3	13.1	13.1	13.4	14.2	15.6	15.7	15.1	15.8	16.3	2%
New Hampshire	14.4	14.3	14.0	13.4	13.5	14.3	15.0	14.4	14.8	15.8	1%
Vermont	12.9	13.4	14.0	14.3	14.7	14.6	14.5	14.5	14.6	15.2	2%
New York	15.5	16.3	15.8	15.1	15.4	16.1	15.3	14.5	14.8	14.5	-1%
Maine	12.6	12.5	12.3	11.5	11.7	12.7	12.5	12.1	12.1	12.5	0%
New Jersey	13.8	13.9	13.5	12.8	12.8	13.2	12.8	12.3	12.3	12.2	-1%
District of Columbia	13.3	13.4	12.9	12.0	11.9	12.2	12.0	11.7	11.7	12.0	-1%
Alabama	10.1	10.2	10.5	10.6	10.5	10.8	10.8	11.1	11.6	11.2	1%
MICHIGAN	9.2	9.8	10.3	10.9	11.1	10.9	10.6	10.6	11.0	11.2	2%
Wisconsin	9.6	10.0	10.4	10.5	10.7	10.8	10.9	10.8	10.9	10.7	1%
Kansas	7.9	8.3	8.8	9.2	9.7	10.1	10.1	10.5	10.6	10.7	3%
Arizona	9.4	9.5	9.5	9.5	9.9	10.1	10.4	10.4	10.5	10.6	1%
Indiana	8.3	8.4	8.8	9.1	9.6	10.0	9.8	10.0	10.5	10.6	2%
Tennessee	9.6	9.7	10.3	10.3	10.0	10.4	10.2	10.2	10.6	10.5	1%
Mississippi	9.5	9.3	9.5	9.3	10.1	10.8	10.6	9.6	10.2	10.4	1%
Maryland	12.0	11.8	11.3	10.4	10.7	11.2	11.0	11.0	10.8	10.4	-1%
Minnesota	7.9	8.4	8.6	8.8	9.4	9.9	9.4	9.9	10.5	10.4	3%
Montana	8.3	8.6	9.1	9.1	9.5	9.6	10.2	10.2	10.1	10.1	2%
South Carolina	8.7	8.9	9.3	9.6	9.9	10.3	10.2	10.3	10.6	10.1	1%
Ohio	9.7	9.7	9.6	9.5	9.4	9.8	10.1	10.0	10.1	10.1	0%
Colorado	8.2	9.1	9.4	9.4	9.9	10.1	9.9	9.6	9.9	10.0	2%
New Mexico	8.4	8.6	9.1	9.3	9.7	10.3	10.3	9.8	10.2	10.0	2%
Georgia	8.9	9.1	9.9	9.6	10.0	10.4	9.9	9.8	10.1	9.8	1%
Kentucky	7.6	7.9	8.5	8.7	8.6	9.4	9.4	9.6	9.9	9.7	2%
Iowa	7.6	7.9	7.9	8.0	8.4	8.7	8.9	9.2	9.5	9.7	3%
Delaware	12.0	11.4	10.6	10.1	10.2	10.5	10.3	10.1	9.9	9.7	-2%
South Dakota	7.1	7.6	7.8	8.1	8.5	8.9	9.2	9.6	9.7	9.6	3%
Wyoming	7.3	7.4	7.7	8.2	8.6	8.9	9.1	9.4	9.7	9.6	3%
Missouri	7.0	7.5	8.0	8.2	8.8	8.9	9.2	9.3	9.5	9.4	3%
West Virginia	6.8	7.7	8.1	8.4	8.2	8.0	8.6	9.4	9.6	9.2	3%
Florida	10.8	9.8	9.9	9.7	9.4	9.9	9.5	8.9	9.4	9.2	-2%
Illinois	9.0	8.9	8.6	8.0	8.1	9.3	9.0	9.0	9.1	9.1	0%
North Dakota	6.8	7.2	7.6	8.0	8.4	8.8	8.8	9.2	9.2	9.1	3%
Pennsylvania	9.6	10.1	10.0	9.4	9.3	9.7	9.6	9.2	9.0	8.9	-1%
Oregon	7.5	7.6	8.2	8.3	8.7	8.8	8.8	8.9	8.9	8.9	2%
Louisiana	7.7	8.5	8.4	7.8	9.0	9.1	8.7	8.6	9.0	8.9	1%
Nebraska	7.3	7.6	8.0	8.4	8.6	8.7	8.7	8.8	8.9	8.8	2%
Washington	7.0	7.4	7.5	7.7	7.8	8.0	8.2	8.4	8.6	8.7	2%
North Carolina	8.0	8.2	8.1	8.7	8.8	8.8	8.7	8.6	8.4	8.6	1%
Virginia	8.1	7.7	8.0	8.1	8.0	8.2	8.2	7.9	8.0	8.3	0%
Utah	7.0	7.2	7.4	8.1	8.3	8.5	8.6	8.8	8.6	8.2	2%
Texas	9.7	9.2	8.8	8.2	8.0	8.2	8.2	8.3	8.3	8.2	-2%
Oklahoma	6.8	7.5	7.6	7.3	7.8	8.1	7.7	7.7	8.1	8.1	2%
Idaho	6.5	6.6	6.4	6.9	7.4	7.8	7.8	7.8	8.0	7.9	2%
Arkansas	7.6	7.3	7.5	7.7	8.1	8.1	8.3	8.2	8.5	7.8	0%
Nevada	10.6	9.8	9.1	8.8	9.0	9.5	9.3	7.9	8.0	7.7	-3%

Industrial Sector Electricity Rates

As shown in Figure 23, Michigan's 7.1 cents per kilowatt-hour price of electricity for the industrial sector is just below the median relative to other states, ranking 24th highest overall.

Figure 24 shows that Michigan's electricity price for industrial customers has been stable, increasing at a compound annual growth rate of just 0.2%, much lower than the rate of increase for the commercial and residential sectors. Among Michigan's peer states, only Ohio and Illinois have lower industrial electricity rates.

Figure 23: 2018 Industrial Electricity Price

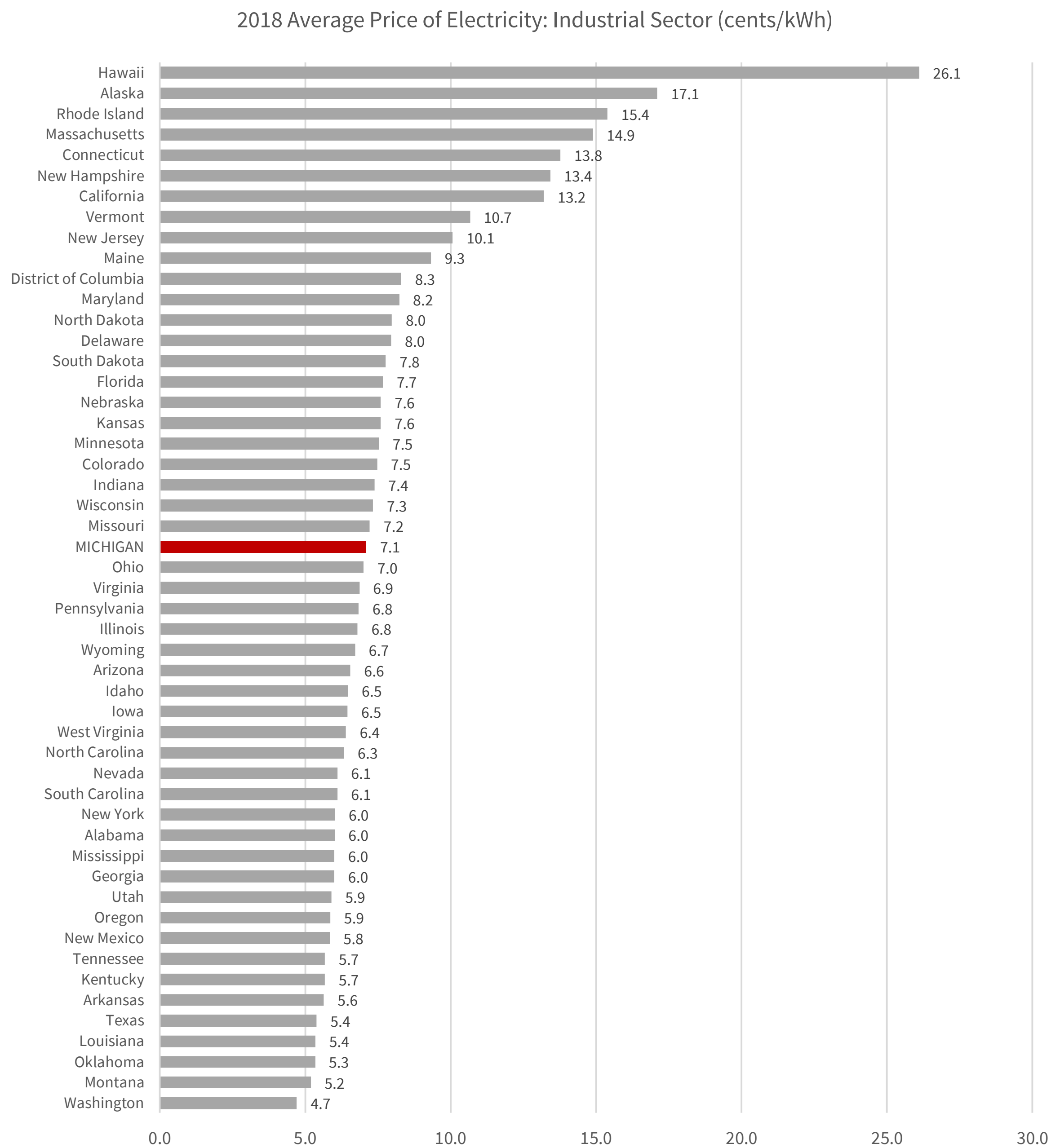


Figure 24: Industrial Electricity Price

Average Price of Electricity: Industrial Sector (cents/kWh)											
State	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR
Hawaii	18.1	21.9	28.4	30.8	29.9	30.2	23.1	20.7	22.9	26.1	4%
Alaska	13.2	14.1	15.7	16.8	15.8	15.7	14.5	15.2	16.3	17.1	3%
Rhode Island	12.2	11.8	11.3	10.7	11.8	12.9	13.8	13.5	14.6	15.4	2%
Massachusetts	14.1	13.7	13.4	12.6	13.2	12.7	13.5	13.4	13.9	14.9	1%
Connecticut	15.0	14.5	13.2	12.7	12.6	12.9	13.0	12.8	13.1	13.8	-1%
New Hampshire	13.7	12.8	12.3	11.8	11.4	11.9	12.7	12.3	12.3	13.4	0%
California	10.4	9.8	10.1	10.5	11.4	12.3	12.2	11.9	12.7	13.2	2%
Vermont	9.2	9.5	9.8	10.0	10.8	10.2	10.3	10.2	10.2	10.7	1%
New Jersey	11.9	11.8	11.4	10.5	10.8	11.4	10.6	10.2	10.1	10.1	-2%
Maine	10.0	9.2	8.9	8.0	8.3	9.0	9.1	9.0	9.2	9.3	-1%
District of Columbia	8.4	7.7	6.9	5.5	5.5	8.4	8.8	8.8	8.2	8.3	0%
Maryland	10.0	9.6	8.8	8.1	8.4	9.0	8.5	7.9	8.4	8.2	-2%
North Dakota	5.3	5.8	6.2	6.6	7.1	7.6	8.1	8.0	7.6	8.0	4%
Delaware	9.5	9.6	8.9	8.4	8.4	8.6	8.3	8.1	7.8	8.0	-2%
South Dakota	5.7	6.1	6.2	6.6	7.0	7.0	7.4	7.6	7.8	7.8	3%
Florida	9.3	8.9	8.6	8.0	7.6	7.9	8.2	7.7	7.8	7.7	-2%
Nebraska	5.8	6.0	6.4	7.0	7.4	7.5	7.6	7.7	7.7	7.6	3%
Kansas	6.1	6.2	6.7	7.1	7.4	7.8	7.6	7.5	7.5	7.6	2%
Minnesota	6.3	6.3	6.5	6.5	7.0	6.7	7.0	7.4	7.4	7.5	2%
Colorado	6.4	6.9	7.1	7.0	7.3	7.5	7.4	7.4	7.5	7.5	2%
Indiana	5.8	5.9	6.2	6.3	6.7	7.0	6.9	7.0	7.5	7.4	2%
Wisconsin	6.7	6.9	7.3	7.3	7.4	7.5	7.6	7.5	7.5	7.3	1%
Missouri	5.4	5.5	5.9	5.9	6.3	6.4	6.4	7.1	7.3	7.2	3%
MICHIGAN	7.0	7.1	7.3	7.6	7.7	7.7	7.0	6.9	7.2	7.1	0%
Ohio	6.7	6.4	6.1	6.2	6.2	6.8	7.0	7.0	6.9	7.0	0%
Virginia	6.9	6.7	6.5	6.7	6.6	6.9	7.0	6.6	6.5	6.9	0%
Pennsylvania	7.2	7.7	7.7	7.2	7.0	7.4	7.2	6.9	6.8	6.8	-1%
Illinois	7.0	6.8	6.4	5.8	5.9	6.9	6.7	6.5	6.5	6.8	0%
Wyoming	4.8	5.0	5.4	6.0	6.4	6.6	6.8	6.9	6.9	6.7	3%
Arizona	6.7	6.6	6.6	6.5	6.7	6.5	6.3	6.1	6.5	6.6	0%
Idaho	5.2	5.2	5.1	5.5	6.1	6.4	6.6	6.6	6.7	6.5	2%
Iowa	5.3	5.4	5.2	5.3	5.6	5.7	5.9	6.1	6.2	6.5	2%
West Virginia	5.2	5.9	6.2	6.3	6.2	5.9	6.1	6.6	6.6	6.4	2%
North Carolina	6.0	6.2	6.0	6.4	6.5	6.5	6.5	6.3	6.2	6.3	1%
Nevada	8.0	7.4	6.7	6.5	6.5	7.1	6.8	5.9	6.2	6.1	-3%
South Carolina	5.8	5.7	5.9	6.0	6.0	6.3	6.1	6.1	6.2	6.1	1%
New York	8.4	8.8	7.8	6.7	6.6	6.6	6.3	6.0	5.9	6.0	-3%
Alabama	6.0	6.0	6.3	6.2	6.0	6.2	6.0	6.0	6.2	6.0	0%
Mississippi	6.6	6.3	6.5	6.2	6.3	6.6	6.6	5.8	6.0	6.0	-1%
Georgia	6.1	6.2	6.6	6.0	6.3	6.6	5.9	5.8	6.0	6.0	0%
Utah	4.8	4.9	5.1	5.6	5.9	6.1	6.2	6.3	6.1	5.9	2%
Oregon	5.4	5.4	5.5	5.6	5.8	6.0	6.0	6.1	6.0	5.9	1%
New Mexico	5.7	6.0	6.1	5.8	6.4	6.6	6.3	5.8	6.2	5.8	0%
Tennessee	6.8	6.6	7.2	7.1	6.3	6.4	6.2	5.7	5.8	5.7	-2%
Kentucky	4.9	5.1	5.3	5.4	5.7	5.7	5.5	5.7	5.7	5.7	1%
Arkansas	5.8	5.4	5.6	5.8	6.0	6.0	6.2	6.1	6.1	5.6	0%
Texas	6.7	6.4	6.2	5.6	5.8	6.2	5.6	5.3	5.4	5.4	-2%
Louisiana	5.3	5.8	5.7	4.8	5.9	6.1	5.4	5.1	5.5	5.4	0%
Oklahoma	4.8	5.4	5.5	5.1	5.5	5.9	5.4	5.0	5.4	5.3	1%
Montana	5.5	5.6	5.3	5.1	5.4	5.5	5.3	5.1	5.3	5.2	-1%
Washington	4.4	4.1	4.1	4.1	4.2	4.3	4.4	4.4	4.6	4.7	1%

All Sector Electricity Rates

Michigan's average price of electricity across all sectors ranked 14th highest among all states in 2018, with an average price of 11.4 cents/kWh, as shown in Figure 25. Among its peers, Michigan's average price of electricity across all sectors was highest. Figure 26 shows that Michigan's average price of electricity for all sectors has steadily increased from 2009-2018, increasing at a compound annual growth rate of 2%.

Figure 25: 2018 All Sector Electricity Price

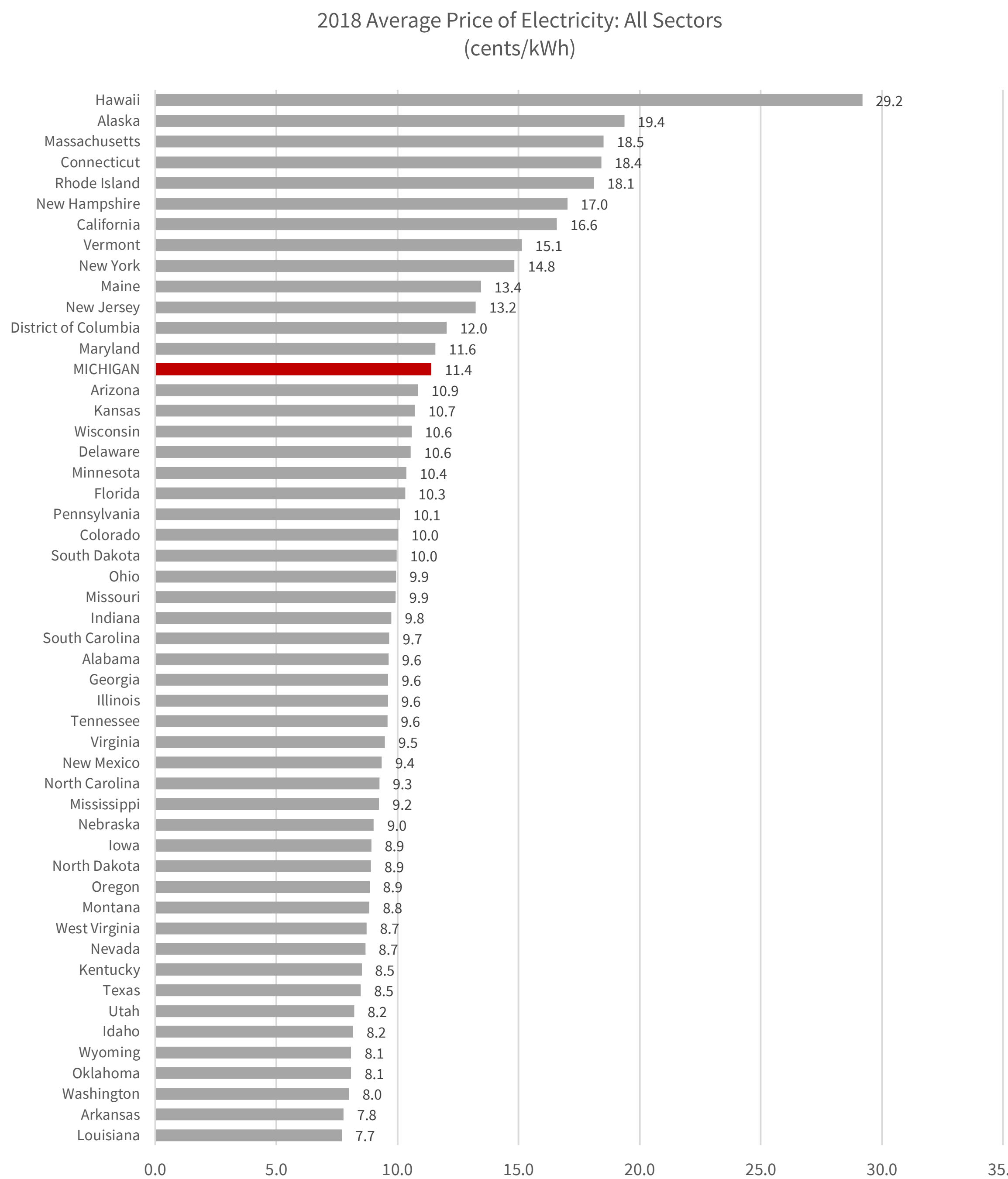


Figure 26: All Sector Electricity Price

Average Price of Electricity: All Sectors (cents/kWh)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Hawaii	21.2	25.1	31.6	34.0	33.3	33.4	26.2	23.9	26.1	29.2	3%
Alaska	15.1	14.8	16.1	16.3	16.5	17.5	17.6	17.9	19.1	19.4	3%
Massachusetts	15.5	14.3	14.1	13.8	14.5	15.4	16.9	16.5	17.1	18.5	2%
Connecticut	18.1	17.4	16.4	15.5	15.7	17.1	17.8	17.2	17.6	18.4	0%
Rhode Island	14.2	14.1	13.0	12.7	13.7	15.4	17.0	16.3	16.4	18.1	2%
New Hampshire	15.1	14.8	14.7	14.2	14.3	15.2	16.0	15.7	16.2	17.0	1%
California	13.2	13.0	13.1	13.5	14.3	15.2	15.4	15.2	16.1	16.6	2%
Vermont	12.8	13.2	13.8	14.2	14.6	14.6	14.4	14.5	14.6	15.1	2%
New York	15.4	16.4	15.9	15.2	15.4	16.3	15.3	14.5	14.7	14.8	0%
Maine	13.1	12.8	12.6	11.8	11.9	12.7	12.8	12.8	13.0	13.4	0%
New Jersey	14.5	14.7	14.3	13.7	13.7	14.0	13.7	13.4	13.3	13.2	-1%
District of Columbia	13.2	13.4	12.8	11.9	11.9	12.1	12.1	11.7	11.8	12.0	-1%
Maryland	13.1	12.7	11.9	11.3	11.7	12.1	12.1	12.2	12.0	11.6	-1%
MICHIGAN	9.4	9.9	10.4	11.0	11.2	11.0	10.8	11.1	11.3	11.4	2%
Arizona	9.6	9.7	9.7	9.8	10.1	10.2	10.3	10.3	10.6	10.9	1%
Kansas	8.0	8.4	8.9	9.3	9.7	10.2	10.1	10.5	10.6	10.7	3%
Wisconsin	9.4	9.8	10.2	10.3	10.5	10.6	10.7	10.7	10.8	10.6	1%
Delaware	12.2	12.0	11.5	11.1	10.9	11.2	11.2	11.1	10.9	10.6	-1%
Minnesota	8.1	8.4	8.7	8.9	9.4	9.5	9.5	10.0	10.3	10.4	2%
Florida	11.5	10.6	10.6	10.4	10.2	10.8	10.5	9.9	10.4	10.3	-1%
Pennsylvania	9.6	10.3	10.5	9.9	9.8	10.3	10.3	10.2	10.1	10.1	1%
Colorado	8.3	9.2	9.4	9.4	9.9	10.1	9.9	9.8	10.0	10.0	2%
South Dakota	7.4	7.8	8.1	8.5	8.9	9.1	9.5	9.8	10.1	10.0	3%
Ohio	9.0	9.1	9.0	9.1	9.2	9.7	10.0	9.8	9.8	9.9	1%
Missouri	7.4	7.8	8.3	8.5	9.0	9.1	9.4	9.7	10.0	9.9	3%
Indiana	7.6	7.7	8.0	8.3	8.7	9.1	9.0	9.2	9.8	9.8	2%
South Carolina	8.4	8.5	8.8	9.1	9.2	9.7	9.6	9.8	10.0	9.7	1%
Alabama	8.8	8.9	9.1	9.2	9.0	9.3	9.3	9.6	9.8	9.6	1%
Georgia	8.8	8.9	9.6	9.4	9.7	10.0	9.6	9.6	9.8	9.6	1%
Illinois	9.2	9.1	9.0	8.4	8.3	9.4	9.4	9.4	9.5	9.6	0%
Tennessee	8.7	8.6	9.3	9.3	9.1	9.4	9.3	9.2	9.5	9.6	1%
Virginia	8.9	8.7	8.8	9.1	9.0	9.2	9.3	9.1	9.2	9.5	1%
New Mexico	8.1	8.4	8.7	8.8	9.3	9.7	9.6	9.1	9.6	9.4	1%
North Carolina	8.5	8.7	8.6	9.2	9.2	9.3	9.4	9.2	9.0	9.3	1%
Mississippi	8.9	8.6	8.8	8.6	9.1	9.6	9.5	8.7	9.1	9.2	0%
Nebraska	7.2	7.5	7.9	8.4	8.7	8.8	8.9	9.1	9.1	9.0	2%
Iowa	7.4	7.7	7.6	7.7	8.1	8.2	8.4	8.6	8.7	8.9	2%
North Dakota	6.6	7.1	7.5	7.8	8.2	8.4	8.8	8.9	8.8	8.9	3%
Oregon	7.5	7.6	8.0	8.2	8.4	8.7	8.8	8.8	8.8	8.9	2%
Montana	7.6	7.8	8.2	8.3	8.6	8.6	8.9	8.8	8.9	8.8	2%
West Virginia	6.7	7.5	7.9	8.1	7.9	7.7	8.1	9.0	9.0	8.7	3%
Nevada	10.4	9.7	9.0	9.0	9.0	9.7	9.5	8.4	8.8	8.7	-2%
Kentucky	6.5	6.7	7.2	7.3	7.7	8.2	8.1	8.4	8.6	8.5	3%
Texas	9.9	9.3	9.0	8.6	8.7	8.9	8.7	8.4	8.4	8.5	-1%
Utah	6.8	6.9	7.1	7.8	8.2	8.4	8.5	8.7	8.6	8.2	2%
Idaho	6.5	6.5	6.4	6.9	7.6	7.9	8.1	8.1	8.3	8.2	2%
Wyoming	6.1	6.2	6.6	7.2	7.6	7.8	8.0	8.2	8.3	8.1	3%
Oklahoma	6.9	7.6	7.8	7.5	7.9	8.2	7.9	7.8	8.2	8.1	2%
Washington	6.6	6.7	6.8	6.9	7.1	7.1	7.4	7.7	7.9	8.0	2%
Arkansas	7.6	7.3	7.4	7.6	7.9	7.9	8.2	8.1	8.3	7.8	0%
Louisiana	7.1	7.8	7.7	6.9	8.0	8.1	7.7	7.5	7.8	7.7	1%

ELECTRIC UTILITY ENVIRONMENTAL METRICS

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 (CO2) which is the principal gas causing climate change and can reduce cognitive function
- 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
- 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 Energy Information Administration. 2018 is the most recent complete compilation currently available and can be obtained from https://www.eia.gov/electricity/data/emissions/. 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. The following table summarizes Michigan's contributions to total pollution and pollution per MWh generated. Pollution quantities are in metric tons (approximately 2200 pounds per metric ton), pollution rates are in metric tons per gigawatt-hour (million kilowatt-hours) of electricity generated, and Michigan's relative rank among the states is shown parenthetically after each of the pollution metrics, with higher rankings signifying better performance.

2018 Metric	Total Pollution (metric tons)	Pollution Intensity (metric tons/GWh)
Carbon Dioxide	61,435,300 (9th highest)	530.4 (19th highest)
Sulfur Dioxide	74,319 (6th highest)	0.64 (10th highest)
Nitrogen Oxides	52,074 (7th highest)	0.45 (18th highest)

Carbon Dioxide Emissions

As shown in Figure 27 Michigan ranked 19th worst among the states in carbon dioxide pollution per gigawatt-hour in 2018 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. Figure 28 shows that Michigan's carbon dioxide emissions per gigawatt-hour have declined at a compound annual growth rate of roughly 3.1% from 2009-2018. This was the 19th highest rate of decrease in the country, and the most rapid rate of decrease among its peers.

Figure 29 shows that Michigan's annual carbon dioxide emissions of 61,435,300 metric tons ranked 9th worst among the states in 2018. Figure 30 shows that Michigan's compound annual growth rate of total carbon dioxide emissions was -1.8% from 2009-2018, the 28th fastest rate of decrease over the period.

Figure 27: 2018 Carbon Dioxide Emission Intensity

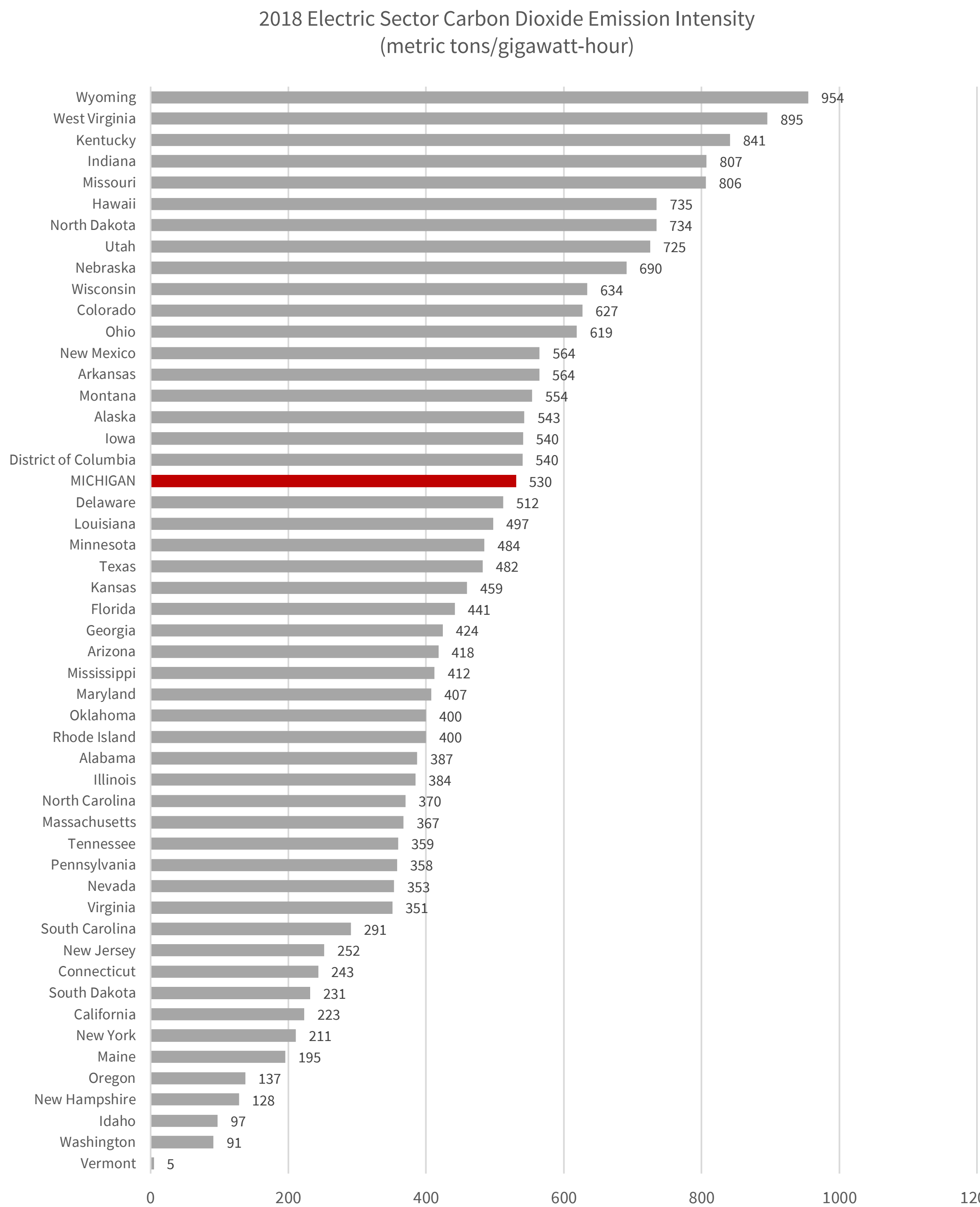


Figure 28: Carbon Dioxide Emission Intensity

Electric Sector Carbon Dioxide Emission Intensity (metric tons/gigawatt-hour)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Wyoming	971	950	949	957	966	953	970	947	947	954	0%
West Virginia	931	919	914	915	908	908	917	902	886	895	0%
Kentucky	951	949	942	953	951	944	915	902	864	841	-1%
Indiana	952	929	897	870	905	907	856	839	828	807	-2%
Missouri	846	854	858	823	855	862	813	798	811	806	0%
Hawaii	787	765	755	728	723	730	727	729	726	735	-1%
North Dakota	954	894	851	856	864	834	841	790	724	734	-3%
Utah	839	841	831	824	840	804	803	741	740	725	-1%
Nebraska	703	668	755	774	756	668	635	630	630	690	0%
Wisconsin	738	734	731	646	723	717	681	630	659	634	-2%
Colorado	771	798	768	760	744	714	714	663	663	627	-2%
Ohio	846	849	828	736	746	734	687	686	668	619	-3%
New Mexico	844	810	816	796	795	765	760	705	685	564	-4%
Arkansas	530	558	586	557	619	605	515	525	548	564	1%
Montana	657	684	565	576	612	584	619	593	564	554	-2%
Alaska	633	610	633	620	580	589	585	547	544	543	-2%
Iowa	829	821	778	728	691	691	618	556	529	540	-4%
District of Columbia	1,007	954	872	921	740	716	662	622	553	540	-6%
MICHIGAN	727	668	635	628	637	602	594	523	520	530	-3%
Delaware	856	744	596	577	608	555	524	500	484	512	-5%
Louisiana	585	571	594	582	571	548	522	496	511	497	-2%
Minnesota	642	614	614	540	570	573	532	498	482	484	-3%
Texas	611	611	614	590	594	582	541	521	530	482	-2%
Kansas	776	758	774	713	683	639	601	541	437	459	-5%
Florida	527	540	516	503	489	492	471	463	451	441	-2%
Georgia	598	600	572	483	470	497	460	451	430	424	-3%
Arizona	478	498	495	472	488	478	444	409	413	418	-1%
Mississippi	482	493	452	445	429	436	389	418	404	412	-2%
Maryland	586	605	565	547	529	547	504	500	392	407	-4%
Oklahoma	693	686	688	631	628	628	547	472	438	400	-5%
Rhode Island	413	416	412	410	454	408	414	407	391	400	0%
Alabama	483	522	489	452	445	453	423	406	380	387	-2%
Illinois	511	512	505	478	482	478	435	386	385	384	-3%
North Carolina	548	569	530	496	452	457	419	401	379	370	-4%
Massachusetts	505	474	431	403	448	415	418	398	385	367	-3%
Tennessee	545	585	561	537	479	521	505	503	453	359	-4%
Pennsylvania	531	535	517	492	479	462	424	395	371	358	-4%
Nevada	485	484	462	424	431	451	378	365	345	353	-3%
Virginia	516	544	490	413	451	437	413	395	345	351	-4%
South Carolina	381	397	376	354	302	341	309	289	272	291	-3%
New Jersey	260	292	261	247	244	270	260	272	240	252	0%
Connecticut	258	276	243	249	245	251	241	235	228	243	-1%
South Dakota	428	359	243	285	319	281	202	232	229	231	-6%
California	290	271	239	298	287	289	282	239	216	223	-3%
New York	286	304	271	263	246	248	236	233	200	211	-3%
Maine	288	291	272	247	262	257	252	222	186	195	-4%
Oregon	166	183	113	121	159	139	155	136	127	137	-2%
New Hampshire	273	250	256	223	174	177	183	131	113	128	-7%
Idaho	78	101	50	76	128	98	119	117	102	97	2%
Washington	129	135	71	60	110	107	106	90	95	91	-3%
Vermont	1	1	4	2	2	2	6	6	7	5	18%

Figure 29: 2018 Carbon Dioxide Emissions

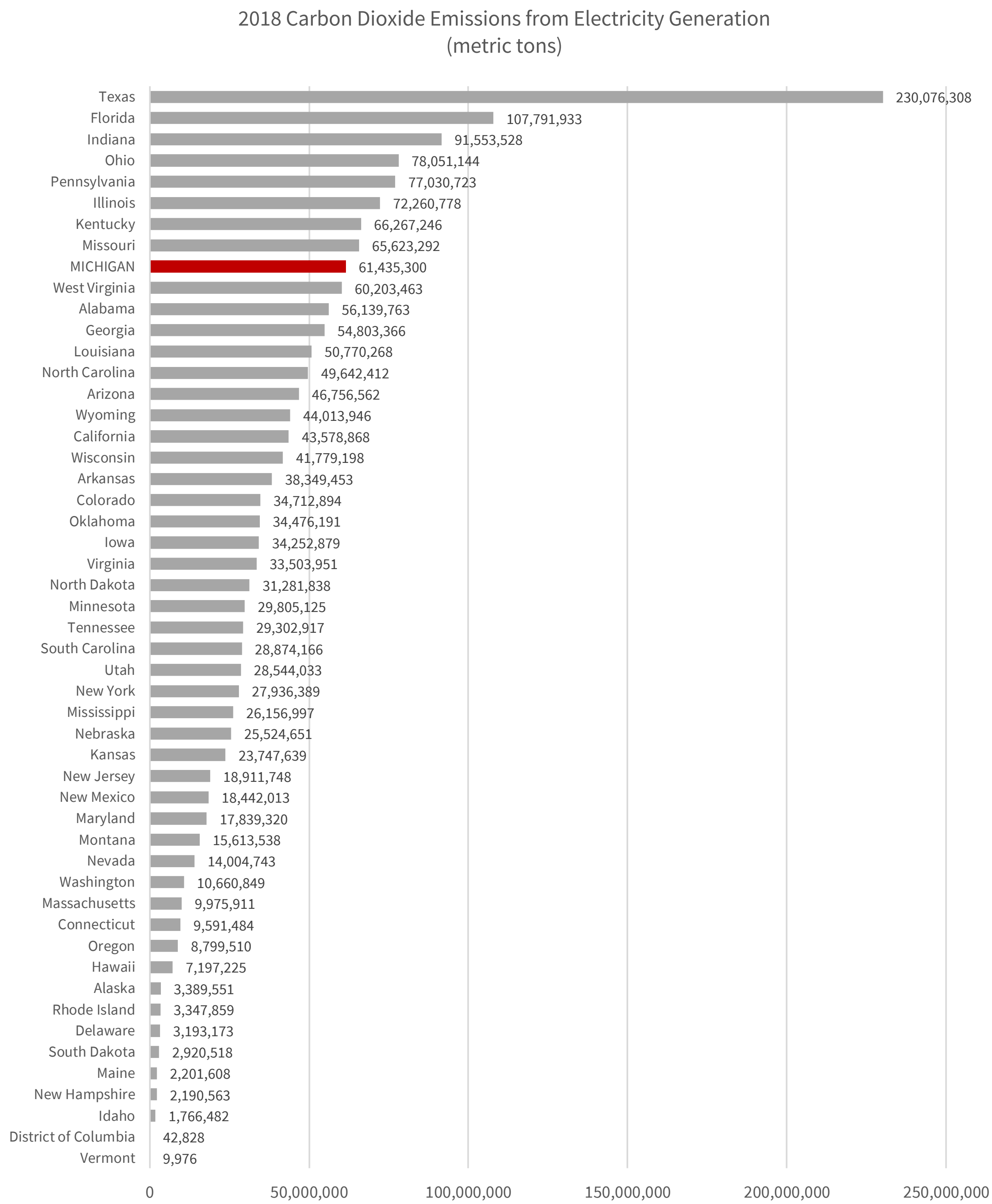


Figure 30: Carbon Dioxide Emissions

Total Carbon Dioxide Emissions from Electricity Generation (metric tons)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Texas	242,864,409	251,409,188	267,464,092	253,689,271	257,464,594	254,487,638	243,386,106	236,457,110	239,991,190	230,076,308	-1%
Florida	114,853,697	123,811,228	114,441,236	111,236,493	108,826,746	113,145,692	111,863,160	110,388,178	107,438,351	107,791,933	-1%
Indiana	111,112,991	116,282,506	109,608,059	99,773,102	99,950,588	104,635,599	89,045,157	85,392,620	81,929,466	91,553,528	-2%
Ohio	115,065,819	121,963,840	112,319,677	95,522,904	102,465,700	98,650,334	83,722,399	81,618,408	79,917,231	78,051,144	-4%
Pennsylvania	116,621,094	122,829,611	117,430,264	109,996,697	108,729,048	102,021,683	90,972,612	85,041,303	79,252,230	77,030,723	-4%
Illinois	98,974,783	103,127,834	100,731,240	94,410,749	97,812,108	96,624,058	84,274,845	72,225,575	70,669,827	72,260,778	-3%
Kentucky	86,155,115	93,159,570	92,693,590	85,682,772	85,303,874	85,795,039	76,427,297	72,432,678	63,251,719	66,267,246	-3%
Missouri	74,715,725	78,814,666	81,427,821	75,544,686	78,344,459	75,735,094	67,995,334	62,730,955	68,644,800	65,623,292	-1%
MICHIGAN	73,588,661	74,479,744	69,301,421	67,876,595	67,192,653	64,263,795	67,119,277	58,643,813	58,413,900	61,435,300	-2%
West Virginia	65,927,761	74,283,350	72,203,110	67,203,074	68,861,856	73,605,609	66,269,845	68,472,932	64,987,884	60,203,463	-1%
Alabama	69,238,676	79,374,763	76,413,476	69,106,650	66,986,027	67,634,537	64,441,792	57,776,234	53,192,095	56,139,763	-2%
Georgia	77,022,270	82,591,913	71,368,349	59,035,062	56,812,143	62,515,953	59,273,980	60,155,547	54,811,036	54,803,366	-3%
Louisiana	53,225,974	58,706,086	62,680,433	60,182,144	58,273,713	57,136,509	56,298,932	53,161,910	49,960,621	50,770,268	0%
North Carolina	64,845,048	73,240,828	62,797,414	57,923,827	56,939,516	58,578,033	53,824,140	52,492,299	48,704,747	49,642,412	-3%
Arizona	53,523,638	55,683,398	53,535,742	52,349,639	55,342,134	53,684,080	50,201,162	44,530,763	43,739,254	46,756,562	-1%
Wyoming	44,683,966	45,702,951	45,197,424	47,463,359	50,686,615	47,336,758	47,475,543	44,171,630	44,272,504	44,013,946	0%
California	59,427,649	55,405,832	47,907,869	59,369,012	57,323,347	57,506,565	55,481,281	47,007,640	44,432,947	43,578,868	-3%
Wisconsin	44,233,260	47,238,443	46,257,128	41,196,428	47,686,076	43,759,905	45,194,700	40,913,887	42,893,441	41,779,198	-1%
Arkansas	30,427,300	34,018,317	35,925,947	36,233,904	37,345,580	37,288,600	28,587,194	31,725,866	33,321,791	38,349,453	2%
Colorado	38,988,708	40,498,764	39,509,434	39,925,777	39,387,317	38,473,611	37,413,300	36,074,666	35,719,638	34,712,894	-1%
Oklahoma	51,986,033	49,535,558	51,363,938	49,186,422	46,267,826	44,062,605	41,626,050	37,105,622	32,329,300	34,476,191	-4%
Iowa	42,977,893	47,211,320	43,878,873	41,266,985	39,174,823	39,312,084	35,042,903	30,215,540	30,661,462	34,252,879	-2%
Virginia	36,160,554	39,719,081	32,636,730	29,223,189	34,686,454	33,733,804	34,897,976	36,566,152	31,195,217	33,503,951	-1%
North Dakota	32,608,448	31,063,899	29,854,996	30,934,049	30,274,035	30,419,692	31,245,513	29,907,862	30,042,550	31,281,838	0%
Minnesota	33,688,934	32,946,107	32,618,199	28,493,816	29,255,384	32,677,491	30,307,101	29,643,872	28,344,485	29,805,125	-1%
Tennessee	43,457,828	48,196,067	45,472,087	41,740,957	38,117,748	41,405,218	37,977,033	39,926,975	35,792,400	29,302,917	-4%
South Carolina	38,121,415	41,364,022	38,720,130	34,237,555	28,809,424	33,082,757	29,848,999	28,001,045	25,362,253	28,874,166	-3%
Utah	36,517,504	35,519,267	33,942,547	32,484,028	35,698,707	35,204,487	33,688,196	28,244,970	27,697,636	28,544,033	-2%
New York	38,130,088	41,583,758	37,255,875	35,668,748	33,456,396	34,072,093	32,730,725	31,295,191	25,583,556	27,936,389	-3%
Mississippi	23,480,603	26,845,306	23,325,979	24,284,840	22,633,396	24,037,348	25,170,683	26,272,253	24,151,238	26,156,997	1%
Nebraska	23,899,471	24,460,746	27,250,887	26,467,486	28,042,902	26,348,032	25,325,783	23,013,711	22,290,487	25,524,651	1%
Kansas	36,207,066	36,320,932	35,119,242	31,692,844	33,125,351	31,793,540	27,341,044	25,762,154	22,237,999	23,747,639	-4%
New Jersey	16,085,557	19,160,136	16,916,854	16,120,331	15,788,845	18,363,585	19,427,201	21,108,016	18,135,688	18,911,748	2%
New Mexico	33,502,278	29,378,703	31,164,190	29,162,551	28,534,704	24,712,461	24,849,830	23,193,276	22,999,709	18,442,013	-6%
Maryland	25,659,043	26,369,386	23,625,407	20,696,656	18,949,736	20,701,175	18,314,105	18,577,966	13,379,146	17,839,320	-4%
Montana	17,548,159	20,369,529	17,028,546	16,024,096	16,950,683	17,677,641	18,135,505	16,469,969	15,911,336	15,613,538	-1%
Nevada	18,294,514	17,020,408	14,748,277	14,929,193	15,690,455	16,221,708	14,752,014	14,541,813	13,167,197	14,004,743	-3%
Washington	13,525,800	13,983,610	8,228,901	6,989,976	12,542,551	12,484,332	11,586,243	10,228,942	11,007,712	10,660,849	-2%
Massachusetts	19,683,325	20,291,010	16,404,480	14,346,389	14,735,029	12,917,109	13,421,709	12,721,825	12,384,070	9,975,911	-7%
Connecticut	8,046,088	9,201,364	8,196,023	8,987,089	8,726,388	8,452,346	9,049,007	8,578,640	7,874,197	9,591,484	2%
Oregon	9,406,039	10,093,990	6,721,391	7,365,189	9,499,795	8,369,747	8,986,600	8,206,857	7,990,903	8,799,510	-1%
Hawaii	8,661,378	8,286,666	8,100,019	7,624,794	7,428,187	7,447,999	7,356,049	7,256,900	7,124,347	7,197,225	-2%
Alaska	4,240,355	4,125,052	4,346,700	4,304,761	3,768,237	3,557,651	3,676,457	3,466,309	3,531,514	3,389,551	-2%
Rhode Island	3,181,021	3,217,071	3,595,046	3,403,402	2,837,800	2,565,962	2,873,636	2,670,029	2,980,924	3,347,859	1%
Delaware	4,143,250	4,187,304	3,928,280	4,981,052	4,721,744	4,276,415	4,090,991	4,363,423	3,630,182	3,193,173	-3%
South Dakota	3,510,593	3,611,180	2,911,400	3,268,899	3,227,772	3,093,416	1,941,252	2,675,908	2,502,497	2,920,518	-2%
Maine	4,714,269	4,948,153	4,351,148	3,722,435	3,675,406	3,402,910	2,955,775	2,557,331	2,097,632	2,201,608	-7%
New Hampshire	5,507,060	5,551,486	5,126,974	4,294,558	3,447,455	3,457,841	3,653,432	2,526,361	1,976,254	2,190,563	-9%
Idaho	1,024,183	1,213,214	824,805	1,171,935	1,941,753	1,491,553	1,865,710	1,828,906	1,771,092	1,766,482	6%
District of Columbia	35,752	190,742	175,076	66,115	48,726	48,396	35,601	47,554	36,975	42,828	2%
Vermont	6,583	8,016	24,004	12,292	14,632	13,785	11,084	11,526	15,342	9,976	4%

Sulfur Dioxide Emissions

As shown in Figure 31, Michigan ranked 10th worst among the states in sulfur dioxide pollution per gigawatt-hour in 2018 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. Figure 32 shows that Michigan's sulfur dioxide emissions per gigawatt-hour have significantly and steadily declined since 2009, at a compound annual rate of 14%. However, many states have experienced larger rates of decreases over that period, as Michigan ranks 29th worst in the rate of decrease.

Figure 33 shows that Michigan's 2018 sulfur dioxide emissions of 74,319 metric tons ranked 6th worst among the states, with only Illinois and Ohio emitting more sulfur dioxide among the peer group. Michigan's rate of decline in total sulfur dioxide emissions has averaged 13% per year, but 23 states had more rapid declines over the time period as shown in Figure 34.

Figure 31: 2018 Sulfur Dioxide Emission Intensity

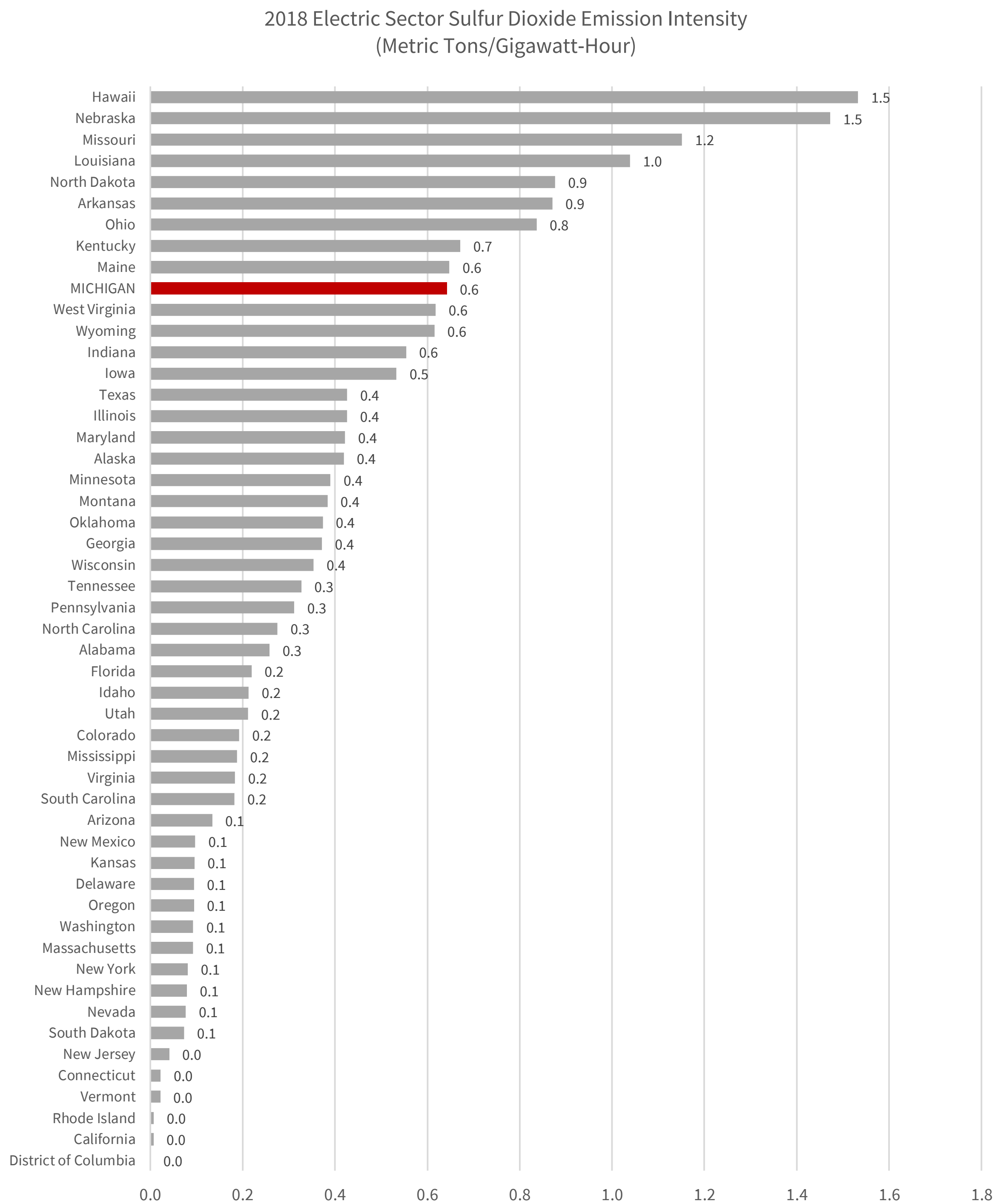


Figure 32: Sulfur Dioxide Emission Intensity

Electric Sector Sulfur Dioxide Emission Intensity (metric tons/gigawatt-hour)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Hawaii	2.0	1.5	1.6	1.4	1.8	1.7	1.9	1.8	1.7	1.5	-3%
Nebraska	2.1	1.8	1.9	1.7	1.6	1.5	1.5	1.3	1.3	1.5	-3%
Missouri	2.7	2.5	2.0	1.5	1.6	1.5	1.4	1.2	1.2	1.2	-8%
Louisiana	1.1	1.2	1.1	1.0	1.1	0.8	0.6	0.5	1.1	1.0	0%
North Dakota	3.5	3.3	2.4	2.2	1.5	1.3	1.2	1.1	0.9	0.9	-13%
Arkansas	1.3	1.2	1.3	1.3	1.3	1.3	1.0	0.9	0.9	0.9	-4%
Ohio	4.6	4.2	4.5	2.7	2.3	2.4	1.8	1.1	0.9	0.8	-16%
Kentucky	2.6	2.5	2.3	1.9	1.9	2.0	1.5	0.9	0.7	0.7	-13%
Maine	2.0	0.7	0.8	0.5	0.9	0.8	0.9	0.6	0.5	0.6	-11%
MICHIGAN	2.8	2.3	2.2	2.0	2.0	1.5	1.2	0.8	0.7	0.6	-14%
West Virginia	2.4	1.3	1.2	1.1	1.1	1.1	0.8	0.5	0.5	0.6	-13%
Wyoming	1.7	1.4	1.6	0.9	0.9	0.8	0.8	0.8	0.7	0.6	-9%
Indiana	3.3	3.1	2.8	2.3	2.2	2.3	1.5	0.8	0.6	0.6	-16%
Iowa	1.8	1.9	1.8	1.7	1.7	1.2	0.8	0.6	0.5	0.5	-11%
Texas	1.1	1.0	0.9	0.8	0.8	0.7	0.5	0.5	0.6	0.4	-9%
Illinois	1.2	1.1	1.0	0.9	0.9	0.8	0.7	0.5	0.4	0.4	-10%
Maryland	4.5	1.0	1.2	1.1	1.1	1.0	0.9	0.7	0.5	0.4	-21%
Alaska	0.6	0.4	0.4	0.4	0.6	0.6	0.6	0.5	0.4	0.4	-3%
Minnesota	1.2	1.1	1.0	0.6	0.6	0.6	0.5	0.4	0.4	0.4	-11%
Montana	0.9	0.7	0.6	0.5	0.6	0.4	0.5	0.4	0.4	0.4	-8%
Oklahoma	1.2	1.2	1.2	1.0	1.0	1.0	0.8	0.6	0.5	0.4	-11%
Georgia	2.3	1.9	1.9	1.2	0.9	0.8	0.5	0.4	0.4	0.4	-17%
Wisconsin	2.3	2.3	2.0	1.5	1.5	1.2	0.8	0.4	0.4	0.4	-17%
Tennessee	1.6	1.7	1.7	1.1	1.0	1.0	1.0	0.6	0.5	0.3	-15%
Pennsylvania	2.7	1.7	1.4	1.1	1.1	1.2	0.9	0.5	0.3	0.3	-19%
North Carolina	1.1	1.0	0.8	0.6	0.5	0.5	0.4	0.4	0.3	0.3	-13%
Alabama	2.0	1.4	1.3	1.0	0.9	0.9	0.8	0.3	0.3	0.3	-18%
Florida	1.0	0.7	0.5	0.5	0.5	0.5	0.3	0.2	0.2	0.2	-14%
Idaho	0.4	0.6	0.3	0.3	0.4	0.3	0.3	0.2	0.2	0.2	-5%
Utah	0.7	0.6	0.6	0.5	0.5	0.5	0.4	0.3	0.3	0.2	-11%
Colorado	0.9	0.9	0.8	0.7	0.7	0.5	0.4	0.3	0.3	0.2	-14%
Mississippi	0.9	1.1	0.9	0.8	1.5	1.7	0.5	0.2	0.2	0.2	-15%
Virginia	1.7	1.6	1.3	0.8	0.8	0.8	0.4	0.3	0.2	0.2	-20%
South Carolina	1.1	1.0	0.8	0.7	0.5	0.4	0.3	0.2	0.2	0.2	-16%
Arizona	0.3	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	-8%
New Mexico	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.2	0.2	0.1	-14%
Kansas	1.0	0.9	0.8	0.7	0.6	0.6	0.3	0.1	0.1	0.1	-21%
Delaware	3.2	2.3	1.3	0.3	0.3	0.1	0.1	0.1	0.1	0.1	-30%
Oregon	0.2	0.3	0.2	0.2	0.3	0.2	0.2	0.1	0.1	0.1	-8%
Washington	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	-3%
Massachusetts	0.9	0.8	0.6	0.4	0.3	0.2	0.1	0.1	0.1	0.1	-20%
New York	0.4	0.5	0.4	0.2	0.2	0.2	0.2	0.1	0.1	0.1	-16%
New Hampshire	1.5	1.5	1.1	0.1	0.2	0.1	0.1	0.0	0.0	0.1	-26%
Nevada	0.2	0.2	0.1	0.1	0.2	0.3	0.1	0.1	0.0	0.1	-9%
South Dakota	1.4	1.2	0.9	1.0	1.4	1.1	0.5	0.1	0.1	0.1	-25%
New Jersey	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	-14%
Connecticut	0.1	0.1	0.0	0.2	0.1	0.1	0.0	0.0	0.0	0.0	-9%
Vermont	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15%
Rhode Island	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	-10%
California	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-7%
District of Columbia	8.0	4.0	3.3	0.0	0.0	0.0	0.0	0.1	0.0	0.0	-100%

Figure 33: 2018 Sulfur Dioxide Emissions

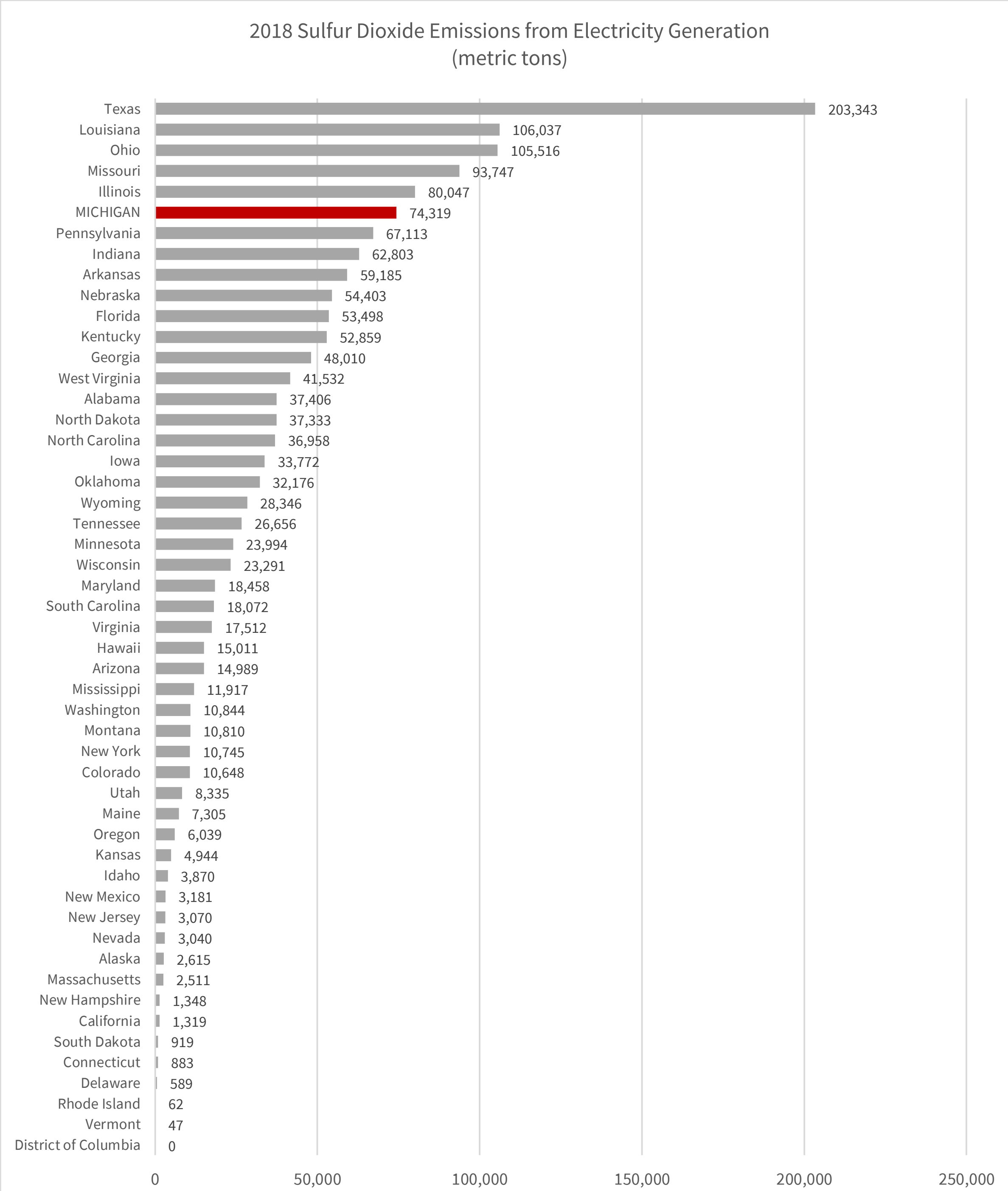


Figure 34: Sulfur Dioxide Emissions

Total Sulfur Dioxide Emissions from Electricity Generation (metric tons)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Texas	418,812	430,123	404,706	349,801	348,118	316,796	247,204	233,185	260,854	203,343	-7%
Louisiana	97,719	125,805	117,904	107,877	111,206	87,300	69,367	57,675	111,441	106,037	1%
Ohio	624,089	610,245	615,752	354,795	314,681	322,153	213,937	130,825	108,956	105,516	-16%
Missouri	235,573	232,804	189,516	135,891	142,871	135,932	114,418	93,149	97,634	93,747	-9%
Illinois	237,489	231,534	207,202	172,478	185,024	170,133	138,639	97,581	77,794	80,047	-10%
MICHIGAN	288,419	253,812	235,343	214,979	215,080	157,408	136,634	92,489	75,905	74,319	-13%
Pennsylvania	584,624	387,433	313,135	240,386	251,154	269,973	200,733	99,539	68,181	67,113	-19%
Indiana	383,580	384,961	346,798	259,601	248,314	269,711	156,720	83,121	58,751	62,803	-17%
Arkansas	75,326	74,060	80,361	83,857	80,569	81,218	53,994	54,278	55,803	59,185	-2%
Nebraska	69,984	64,875	68,014	57,785	60,677	58,054	58,937	47,240	46,593	54,403	-2%
Florida	219,347	159,795	113,046	101,213	106,865	114,854	76,734	58,895	54,300	53,498	-13%
Kentucky	232,401	248,767	225,925	171,011	173,076	185,856	122,282	72,289	54,652	52,859	-14%
Georgia	294,594	264,774	236,889	148,902	112,245	97,402	66,988	52,680	47,604	48,010	-17%
West Virginia	167,273	105,270	97,955	82,753	85,172	92,899	60,879	41,540	36,114	41,532	-13%
Alabama	284,909	217,903	195,481	147,865	131,148	139,203	116,838	49,210	35,674	37,406	-18%
North Dakota	120,594	115,641	85,755	79,101	51,575	47,823	42,886	43,146	37,484	37,333	-11%
North Carolina	126,172	130,673	91,297	73,568	64,672	58,199	52,185	47,267	39,336	36,958	-12%
Iowa	92,180	107,935	101,233	95,888	96,960	68,558	43,505	31,392	30,862	33,772	-10%
Oklahoma	91,731	84,805	89,917	74,390	72,953	71,265	60,943	49,789	39,799	32,176	-10%
Wyoming	76,030	67,422	77,571	43,557	44,986	41,462	40,089	35,156	34,640	28,346	-9%
Tennessee	124,970	137,764	138,272	88,296	78,204	81,064	78,524	48,493	40,128	26,656	-14%
Minnesota	64,770	56,597	52,459	33,235	32,318	35,623	27,246	24,215	21,564	23,994	-9%
Wisconsin	139,466	144,871	127,664	97,602	98,255	73,704	54,238	28,005	24,602	23,291	-16%
Maryland	197,131	45,090	48,756	40,462	37,681	37,528	31,174	24,685	15,540	18,458	-21%
South Carolina	105,134	105,821	87,413	64,666	43,245	39,606	26,116	23,097	17,398	18,072	-16%
Virginia	117,634	119,828	86,338	55,685	61,762	62,180	30,606	26,653	18,916	17,512	-17%
Hawaii	22,280	16,747	16,872	14,583	18,198	16,922	19,633	17,782	17,011	15,011	-4%
Arizona	32,883	33,371	29,710	19,419	21,507	20,495	16,023	11,740	12,117	14,989	-8%
Mississippi	45,406	59,043	48,347	42,940	79,577	91,709	33,113	12,161	11,174	11,917	-13%
Washington	12,643	14,174	17,973	20,084	12,028	12,440	11,546	10,981	10,846	10,844	-2%
Montana	22,793	22,033	17,982	14,977	15,300	13,087	13,244	11,303	11,694	10,810	-7%
New York	58,872	61,722	51,898	30,818	28,076	28,919	21,720	18,372	15,154	10,745	-16%
Colorado	43,184	44,876	42,529	38,869	36,296	25,814	21,712	17,813	14,098	10,648	-13%
Utah	29,616	25,495	22,571	20,027	21,471	21,453	15,568	11,212	10,012	8,335	-12%
Maine	32,926	12,419	12,281	8,231	12,130	10,044	10,720	7,000	5,990	7,305	-14%
Oregon	11,922	15,862	13,511	13,462	15,882	9,732	8,739	7,996	7,037	6,039	-7%
Kansas	46,772	41,048	35,728	29,889	27,236	28,623	12,645	6,476	5,044	4,944	-20%
Idaho	4,622	6,642	4,725	5,288	5,955	5,245	4,218	3,761	3,710	3,870	-2%
New Mexico	17,506	15,032	16,167	15,023	16,087	10,942	10,546	7,493	8,203	3,181	-16%
New Jersey	11,791	13,954	4,929	3,902	2,905	3,061	3,326	2,818	2,858	3,070	-13%
Nevada	7,186	7,161	4,790	4,264	6,743	9,279	4,852	2,444	1,778	3,040	-8%
Alaska	3,710	3,015	2,728	2,704	3,810	3,532	3,777	3,165	2,559	2,615	-3%
Massachusetts	33,432	34,938	21,922	14,894	11,141	6,076	4,699	3,361	2,862	2,511	-23%
New Hampshire	30,702	33,808	22,542	2,054	3,384	2,818	2,061	883	778	1,348	-27%
California	2,949	2,522	2,741	5,505	1,888	2,792	1,243	2,449	1,323	1,319	-8%
South Dakota	11,140	11,912	10,208	11,634	13,923	12,568	4,360	753	774	919	-22%
Connecticut	1,862	2,032	880	7,257	3,183	1,703	1,309	570	670	883	-7%
Delaware	15,699	13,152	8,441	2,427	2,032	749	743	465	494	589	-28%
Rhode Island	155	49	72	28	1,152	88	100	86	78	62	-9%
Vermont	38	38	85	47	65	62	60	50	60	47	2%
District of Columbia	284	797	656	0	0	0	0	5	0	0	-100%

Nitrogen Oxides Emissions

As shown in Figure 35, Michigan ranked 18th worst among the states in nitrogen oxides emitted per gigawatt-hour in 2018 with 0.45 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 -7% is the 17th fastest annual rate of decline from 2009-2018 as shown in Figure 36

Michigan ranks 7th worst in total nitrogen oxide emissions in 2018 as shown in Figure 37. Figure 38 shows that Michigan's annual rate of decline in total nitrogen oxide emissions of 5% is the 23rd fastest in the country, slower than all its peer states except for Indiana.

Figure 35: 2018 Nitrogen Oxide Emission Intensity

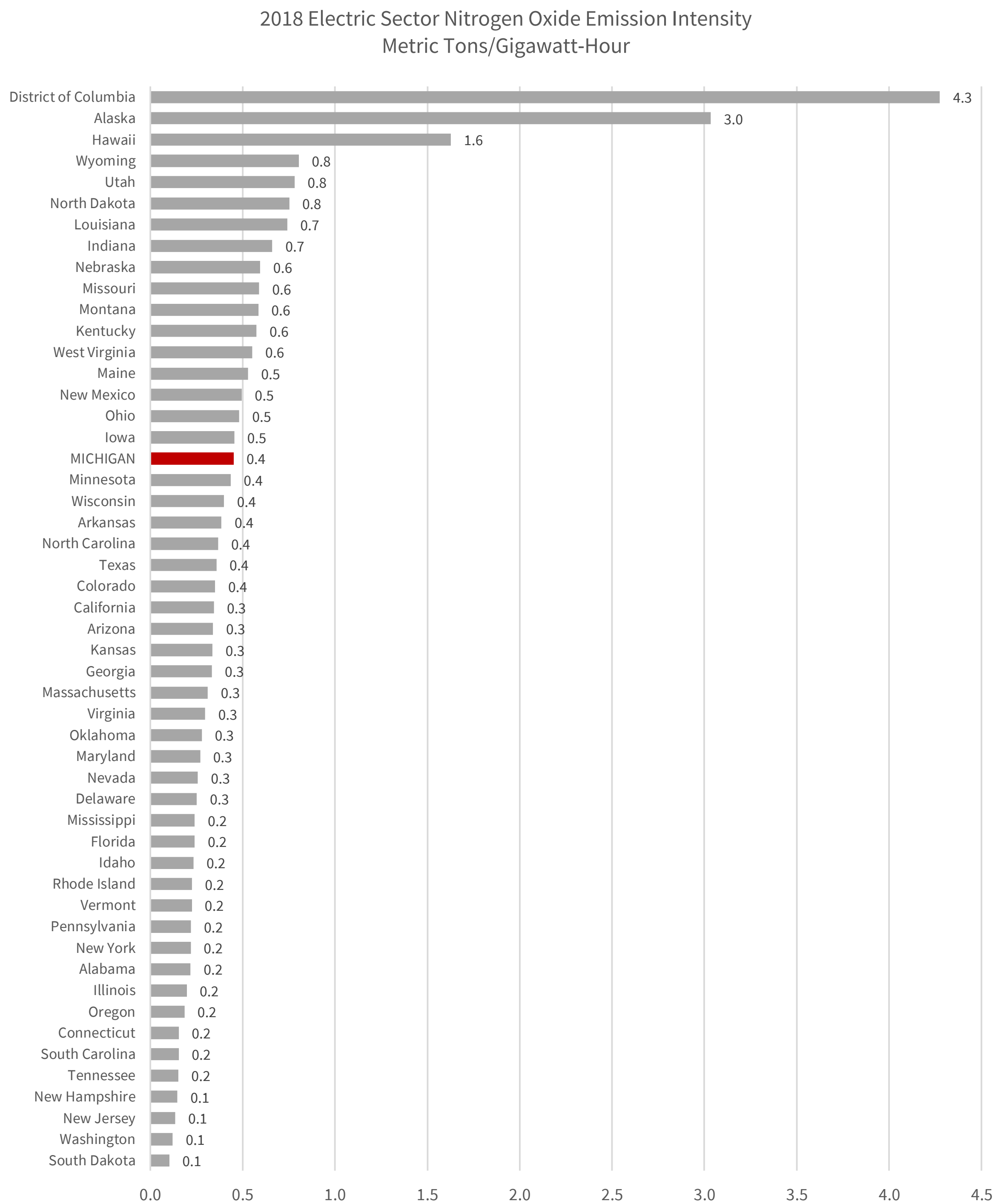


Figure 36: Nitrogen Oxide Emission Intensity

Electric Sector Nitrogen Oxide Emission Intensity (metric tons/gigawatt-hour)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
District of Columbia	3.7	1.8	1.8	2.9	2.0	2.0	4.2	4.5	4.4	4.3	2%
Alaska	2.5	2.4	2.5	2.4	2.5	2.4	3.1	3.3	3.2	3.0	2%
Hawaii	2.0	1.9	1.9	1.8	2.1	1.8	1.7	1.6	1.6	1.6	-2%
Wyoming	1.4	1.3	1.3	1.0	1.0	0.9	0.9	0.8	0.8	0.8	-6%
Utah	1.6	1.6	1.4	1.2	1.3	1.2	1.1	0.9	0.8	0.8	-7%
North Dakota	1.7	1.5	1.4	1.3	1.3	1.2	1.1	0.9	0.8	0.8	-8%
Louisiana	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.7	0.7	0%
Indiana	1.0	1.0	1.0	0.9	1.0	1.0	0.9	0.9	0.7	0.7	-4%
Nebraska	1.3	1.1	1.1	0.8	0.8	0.6	0.6	0.5	0.6	0.6	-8%
Missouri	0.6	0.6	0.6	0.7	0.8	0.8	0.5	0.7	0.6	0.6	0%
Montana	0.8	0.7	0.6	0.6	0.7	0.6	0.6	0.6	0.5	0.6	-3%
Kentucky	0.8	0.9	0.9	0.8	0.9	0.9	0.7	0.7	0.6	0.6	-3%
West Virginia	0.5	0.6	0.7	0.7	0.7	0.8	0.8	0.6	0.5	0.6	1%
Maine	0.8	0.5	0.5	0.4	0.6	0.6	0.7	0.5	0.5	0.5	-4%
New Mexico	1.5	1.5	1.5	1.5	1.5	1.3	1.3	1.1	1.0	0.5	-11%
Ohio	0.8	0.9	0.9	0.7	0.7	0.7	0.6	0.5	0.5	0.5	-5%
Iowa	0.9	0.9	0.8	0.7	0.7	0.7	0.5	0.5	0.5	0.5	-6%
MICHIGAN	0.9	0.8	0.8	0.7	0.7	0.7	0.5	0.5	0.4	0.4	-7%
Minnesota	0.9	0.8	0.8	0.7	0.7	0.6	0.5	0.4	0.4	0.4	-7%
Wisconsin	0.8	0.8	0.7	0.6	0.6	0.6	0.5	0.4	0.4	0.4	-7%
Arkansas	0.6	0.7	0.7	0.6	0.7	0.7	0.5	0.5	0.5	0.4	-5%
North Carolina	0.4	0.4	0.4	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0%
Texas	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	-3%
Colorado	1.1	1.1	1.0	0.9	0.8	0.7	0.7	0.5	0.5	0.4	-11%
California	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	-2%
Arizona	0.6	0.5	0.5	0.4	0.5	0.4	0.4	0.3	0.3	0.3	-5%
Kansas	1.0	1.0	0.9	0.7	0.6	0.5	0.4	0.4	0.3	0.3	-10%
Georgia	0.6	0.6	0.6	0.4	0.4	0.4	0.4	0.3	0.3	0.3	-5%
Massachusetts	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	-3%
Virginia	0.6	0.7	0.7	0.5	0.5	0.5	0.4	0.3	0.3	0.3	-6%
Oklahoma	1.0	1.0	1.0	0.8	0.7	0.6	0.4	0.3	0.3	0.3	-12%
Maryland	0.5	0.6	0.6	0.6	0.6	0.5	0.4	0.4	0.3	0.3	-7%
Nevada	0.4	0.4	0.4	0.3	0.4	0.4	0.3	0.3	0.2	0.3	-5%
Delaware	1.2	0.9	0.6	0.3	0.3	0.3	0.3	0.2	0.2	0.3	-14%
Mississippi	0.6	0.6	0.5	0.4	0.4	0.4	0.2	0.2	0.2	0.2	-8%
Florida	0.5	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.2	-8%
Idaho	0.2	0.3	0.2	0.3	0.4	1.2	0.8	0.3	0.3	0.2	4%
Rhode Island	0.4	0.4	0.3	0.3	0.2	0.1	0.1	0.1	0.2	0.2	-5%
Vermont	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.2	0.2	10%
Pennsylvania	0.5	0.6	0.6	0.6	0.6	0.6	0.5	0.4	0.2	0.2	-9%
New York	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	-4%
Alabama	0.4	0.4	0.4	0.3	0.3	0.4	0.3	0.2	0.2	0.2	-5%
Illinois	0.4	0.4	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.2	-7%
Oregon	0.2	0.3	0.2	0.1	0.2	0.2	0.3	0.2	0.2	0.2	-2%
Connecticut	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	-3%
South Carolina	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.1	0.2	-4%
Tennessee	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.2	0.2	-9%
New Hampshire	0.3	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	-6%
New Jersey	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	-5%
Washington	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-4%
South Dakota	1.4	1.2	0.8	0.9	1.0	0.9	0.3	0.1	0.1	0.1	-23%

Figure 37: 2018 Nitrogen Oxide Emissions

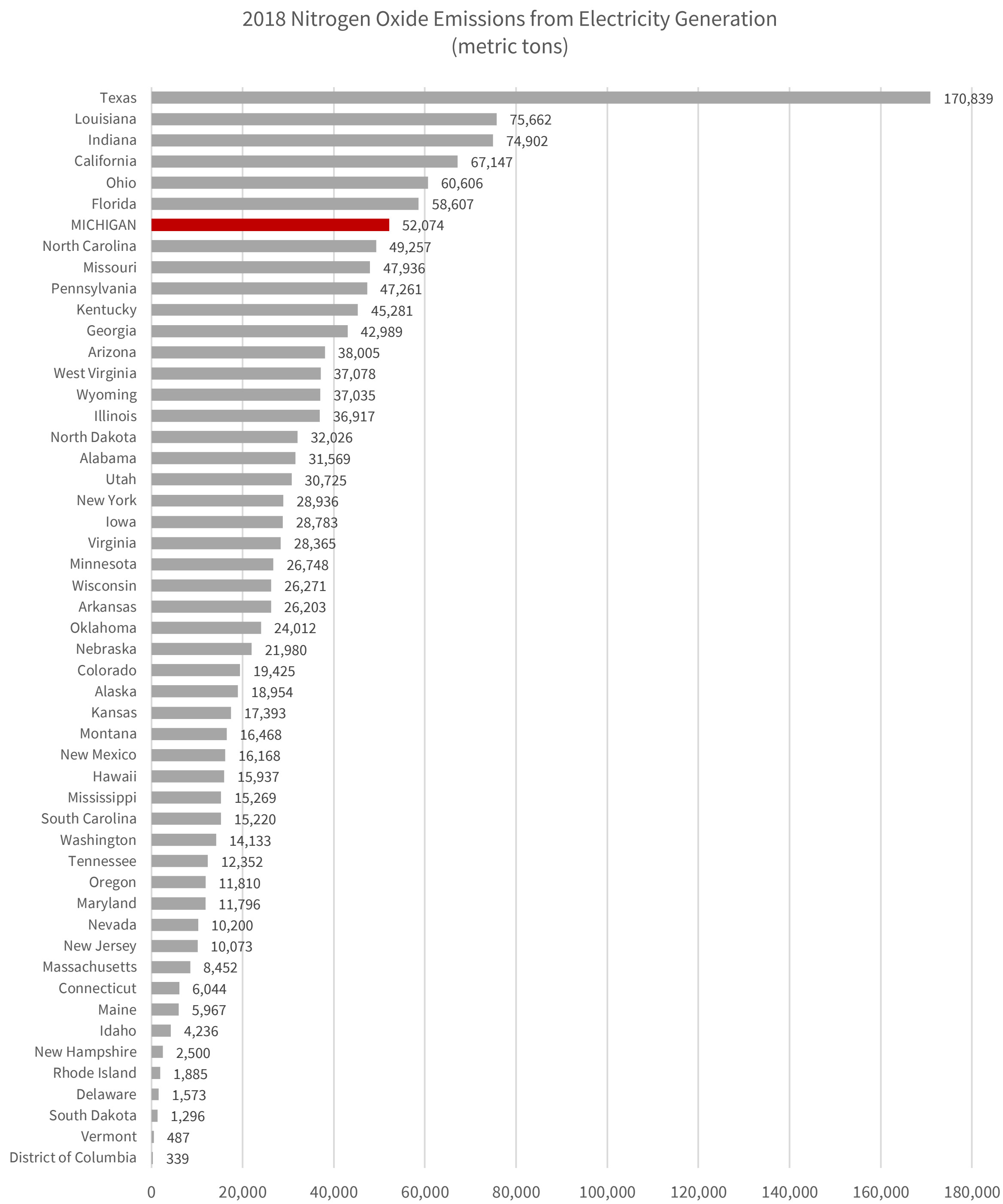


Figure 38: Nitrogen Oxide Emissions

Total Nitrogen Oxide Emissions from Electricity Generation (metric tons)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Texas	199,086	203,537	214,297	193,567	204,222	187,101	172,159	165,928	165,551	170,839	-2%
Louisiana	69,175	75,394	77,683	74,954	74,649	69,667	70,532	66,405	70,970	75,662	1%
Indiana	110,914	120,437	119,803	107,337	110,057	115,415	97,256	89,320	70,276	74,902	-4%
California	83,201	79,589	81,366	83,968	77,905	73,880	72,756	69,143	68,521	67,147	-2%
Ohio	110,211	122,434	121,496	90,986	92,523	95,541	76,070	64,932	65,391	60,606	-6%
Florida	115,829	100,791	82,935	83,920	79,567	82,273	76,172	70,470	69,635	58,607	-7%
MICHIGAN	91,266	88,864	81,979	80,818	77,340	69,996	61,410	52,456	50,346	52,074	-5%
North Carolina	44,247	57,407	50,015	53,192	56,614	55,053	51,247	47,827	49,202	49,257	1%
Missouri	51,561	56,116	60,751	66,433	70,760	70,508	44,148	53,659	47,343	47,936	-1%
Pennsylvania	120,366	135,887	147,475	132,776	137,029	128,269	103,635	87,052	49,474	47,261	-9%
Kentucky	73,900	84,856	85,102	74,928	79,108	80,970	61,674	54,616	44,110	45,281	-5%
Georgia	73,879	79,274	75,152	50,103	50,317	52,917	48,158	42,842	41,504	42,989	-5%
Arizona	61,622	57,244	52,782	45,718	51,073	48,288	43,079	36,372	35,042	38,005	-5%
West Virginia	34,677	49,153	55,244	48,157	54,639	66,219	56,723	47,510	39,941	37,078	1%
Wyoming	65,999	61,363	61,629	49,167	50,455	44,974	45,124	39,067	37,423	37,035	-6%
Illinois	77,894	82,559	73,047	60,950	57,303	52,524	41,963	35,745	36,070	36,917	-7%
North Dakota	58,995	52,011	48,193	45,950	43,957	44,188	41,815	35,596	31,527	32,026	-6%
Alabama	52,587	66,190	64,716	51,222	51,484	56,502	51,256	35,214	29,166	31,569	-5%
Utah	68,448	68,088	57,787	49,172	56,517	52,561	47,401	33,066	31,759	30,725	-8%
New York	44,093	44,052	42,631	40,269	40,446	40,085	35,306	32,161	28,494	28,936	-4%
Iowa	45,095	49,963	44,201	41,639	40,461	38,038	30,613	26,384	27,092	28,783	-4%
Virginia	39,357	48,812	43,720	35,778	36,017	36,886	34,469	31,660	25,988	28,365	-3%
Minnesota	49,208	44,268	41,421	35,837	33,363	34,629	27,751	25,360	25,264	26,748	-6%
Wisconsin	48,535	48,766	46,025	39,312	40,021	35,854	33,509	28,172	28,195	26,271	-6%
Arkansas	37,075	40,490	41,347	38,243	41,639	42,682	28,688	30,619	30,993	26,203	-3%
Oklahoma	72,664	71,029	76,729	63,455	51,491	40,556	29,381	26,973	23,894	24,012	-10%
Nebraska	44,103	40,030	41,342	28,760	28,585	24,530	23,365	20,065	20,145	21,980	-7%
Colorado	54,296	55,063	51,062	44,994	44,824	40,220	34,876	28,907	24,882	19,425	-10%
Alaska	16,855	16,028	17,268	17,008	15,971	14,390	19,243	21,060	20,871	18,954	1%
Kansas	45,814	45,946	40,995	32,565	27,988	26,324	18,730	17,248	15,606	17,393	-9%
Montana	20,534	21,197	17,369	16,029	19,768	18,631	18,801	16,103	15,156	16,468	-2%
New Mexico	61,165	55,818	57,192	55,454	53,356	41,658	42,414	35,498	34,741	16,168	-12%
Hawaii	22,440	20,892	20,037	18,927	21,558	18,105	17,399	16,288	16,114	15,937	-3%
Mississippi	27,458	30,607	26,293	23,460	22,214	21,765	14,621	14,890	14,364	15,269	-6%
South Carolina	24,280	29,832	30,245	22,267	17,267	19,585	17,569	15,394	13,851	15,220	-5%
Washington	18,293	20,614	14,629	11,897	16,085	15,301	13,931	13,415	14,385	14,133	-3%
Tennessee	30,011	32,911	29,203	25,299	21,033	21,691	20,959	21,754	18,062	12,352	-8%
Oregon	12,605	14,666	9,295	8,754	12,349	11,556	14,939	12,108	12,179	11,810	-1%
Maryland	23,400	24,897	25,315	21,748	19,952	18,713	14,530	13,105	10,678	11,796	-7%
Nevada	16,661	15,267	11,989	12,002	13,309	14,502	9,882	9,962	8,737	10,200	-5%
New Jersey	13,919	14,986	13,140	13,599	13,622	13,933	11,754	11,696	9,752	10,073	-3%
Massachusetts	16,661	17,308	14,062	13,873	13,748	12,552	11,414	10,314	8,959	8,452	-7%
Connecticut	6,483	7,092	6,139	11,750	8,197	7,613	6,902	6,014	5,982	6,044	-1%
Maine	12,397	8,413	7,962	6,618	8,720	7,878	8,132	6,069	6,068	5,967	-7%
Idaho	2,013	4,134	2,897	4,348	6,802	18,353	12,455	4,708	4,824	4,236	8%
New Hampshire	5,488	6,267	5,163	3,978	4,586	3,527	2,882	2,185	1,972	2,500	-8%
Rhode Island	2,855	2,919	2,659	2,277	995	933	948	912	1,806	1,885	-4%
Delaware	5,814	4,814	4,189	2,840	2,346	2,574	2,195	1,954	1,581	1,573	-12%
South Dakota	11,264	11,717	9,408	10,613	10,368	9,650	2,973	1,077	1,075	1,296	-19%
Vermont	627	665	661	610	718	670	612	581	505	487	-2%
District of Columbia	130	367	371	205	134	133	227	341	296	339	10%

Disposition of Generation

The following section displays Michigan's rank for several metrics related to in-state generation from renewable or carbon-free sources. Renewable generation includes utility-scale solar, wind, hydroelectric, geothermal, and biomass. Carbon-free generation includes nuclear generation and all renewables except for biomass. Because these metrics are sorted from worst to best, higher number rankings imply better performance. In graphical terms, states appearing toward the bottom of the bar chart perform better.

2018 Metric	Value	Michigan Rank
Renewable Generation	9,676 GWh	30th worst
Renewable Generation excluding Conventional Hydroelectric	8,106 GWh	38th worst
Renewable Generation as a % of Total Generation	8.35%	20th worst
Renewable Generation excluding Conventional Hydroelectric as a % of Total Generation	7.00%	27th worst
Renewable Generation as a % of Total Sales	9.23%	21st worst
Renewable Generation excluding Conventional Hydroelectric as a % of Total Sales	7.73%	28th worst
Renewable and Carbon-free Generation	40,154 GWh	38th worst
Carbon-free Generation	37,623 GWh	38th worst
Renewable and Carbon-free Generation as a % of Total Generation	34.66 %	25th worst
Carbon-free Generation as a % of Total Generation	32.48%	25th worst
Renewable and Carbon-free Generation as a % of Total Sales	38.29%	26th worst
Carbon-free Generation as a % of Total Sales	35.88%	27th worst

Renewable Generation

Michigan ranked 30th lowest in total generation from renewables. Its compound annual growth rate of 9% ranked lower than Ohio, Indiana, and Illinois.

Figure 39: 2018 Renewable Generation

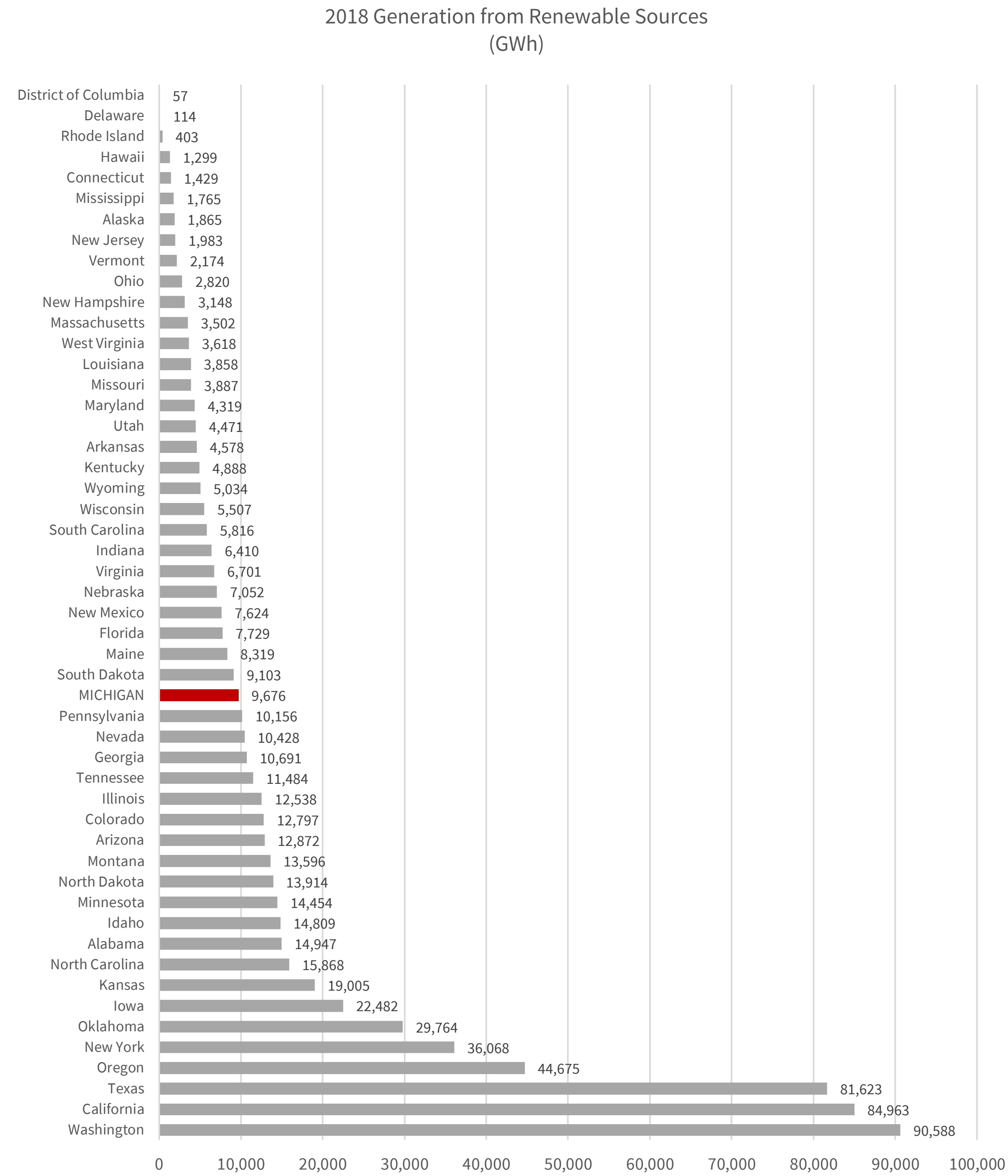


Figure 40: Renewable Generation

Generation from Renewable Sources (GWh)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
District of Columbia	0	0	0	0	0	0	31	53	47	57	
Delaware	126	138	158	131	107	131	130	124	118	114	-1%
Rhode Island	149	144	138	106	57	230	239	248	368	403	10%
Hawaii	817	817	974	1,039	1,205	1,300	1,340	1,438	1,388	1,299	5%
Connecticut	1,268	1,130	1,227	979	1,054	1,203	1,107	1,117	1,177	1,429	1%
Mississippi	1,424	1,504	1,506	1,509	1,448	1,508	1,507	1,524	1,563	1,765	2%
Alaska	1,337	1,452	1,360	1,615	1,633	1,753	1,784	1,871	1,829	1,865	3%
New Jersey	992	868	980	1,291	1,465	1,553	1,605	1,848	1,891	1,983	7%
Vermont	1,915	1,829	1,857	1,616	2,030	1,963	1,977	1,905	2,132	2,174	1%
Ohio	1,161	1,129	1,319	2,153	2,558	2,504	2,515	2,533	2,698	2,820	9%
New Hampshire	2,878	2,710	2,696	2,629	3,123	3,334	3,318	3,267	3,435	3,148	1%
Massachusetts	2,430	2,270	2,355	2,189	2,440	2,632	2,660	2,742	3,219	3,502	4%
West Virginia	2,388	2,307	2,565	2,728	3,129	2,698	2,766	3,070	3,341	3,618	4%
Louisiana	3,600	3,577	3,487	3,110	3,831	3,870	3,704	3,979	3,676	3,858	1%
Missouri	2,391	2,527	2,426	2,013	2,377	1,953	2,774	2,562	3,414	3,887	5%
Maryland	2,440	2,241	3,369	2,555	2,668	2,604	2,691	2,674	3,330	4,319	6%
Utah	1,322	1,476	2,191	1,848	1,437	1,889	1,941	3,205	4,922	4,471	13%
Arkansas	5,778	5,283	4,625	3,859	4,256	4,170	5,011	4,966	4,411	4,578	-2%
Kentucky	3,681	3,020	3,406	2,695	3,602	3,592	3,845	3,955	5,021	4,888	3%
Wyoming	3,193	4,271	5,836	5,263	5,144	5,274	4,625	5,363	5,444	5,034	5%
Wisconsin	3,734	4,586	4,912	4,753	5,171	5,734	5,502	5,783	5,780	5,507	4%
South Carolina	4,080	4,250	3,683	3,564	5,386	5,012	4,858	4,607	4,314	5,816	4%
Indiana	2,209	3,699	4,030	3,980	4,275	4,360	5,499	5,984	6,147	6,410	11%
Virginia	3,896	3,720	3,406	3,402	4,160	4,807	5,303	5,584	5,238	6,701	6%
Nebraska	883	1,807	2,734	2,604	2,993	3,959	4,936	4,757	6,686	7,052	23%
New Mexico	1,851	2,072	2,436	2,797	2,692	2,911	2,834	4,537	6,011	7,624	15%
Florida	4,549	4,664	4,852	4,674	4,913	5,284	5,388	5,042	6,104	7,729	5%
Maine	8,150	7,963	8,474	8,398	8,454	8,115	7,809	7,455	8,431	8,319	0%
South Dakota	4,859	6,611	9,276	8,335	6,750	7,835	7,348	8,520	8,216	9,103	6%
MICHIGAN	3,995	4,083	4,320	4,992	6,933	8,274	8,782	8,764	9,428	9,676	9%
Pennsylvania	6,035	6,577	7,316	6,701	8,279	8,722	8,424	8,317	9,222	10,156	5%
Nevada	4,269	4,444	4,628	5,409	6,372	6,456	7,367	8,666	9,669	10,428	9%
Georgia	6,085	6,502	5,895	5,515	7,553	7,347	7,847	8,827	9,414	10,691	6%
Tennessee	11,162	9,125	10,595	9,132	13,553	10,042	10,707	7,824	9,774	11,484	0%
Illinois	3,666	5,257	7,006	8,484	10,406	10,832	11,448	11,312	12,919	12,538	13%
Colorado	5,132	5,133	7,449	7,689	8,749	9,517	9,427	12,024	12,332	12,797	10%
Arizona	6,630	6,941	9,703	8,415	8,647	9,959	10,671	11,690	12,515	12,872	7%
Montana	10,422	10,442	13,861	12,545	11,398	13,470	11,874	12,243	13,136	13,596	3%
North Dakota	4,484	6,150	7,825	7,757	7,377	8,736	8,603	10,090	13,943	13,914	12%
Minnesota	7,546	7,480	9,152	10,576	10,382	12,005	12,437	13,044	14,924	14,454	7%
Idaho	11,302	10,168	15,297	13,455	11,626	12,479	11,704	12,245	14,224	14,809	3%
Alabama	15,585	11,081	11,700	10,212	15,775	12,246	13,151	10,351	12,844	14,947	0%
North Carolina	7,065	6,840	6,239	6,432	9,855	8,032	8,705	10,400	12,215	15,868	8%
Kansas	2,876	3,473	3,793	5,263	9,506	10,920	11,081	14,202	18,690	19,005	21%
Iowa	8,560	10,309	11,795	14,950	16,476	17,452	19,091	21,241	22,621	22,482	10%
Oklahoma	6,482	6,969	7,426	9,666	13,684	13,704	17,033	23,010	25,966	29,764	16%
New York	32,082	30,286	32,893	29,845	30,861	32,534	32,333	33,212	36,750	36,068	1%
Oregon	37,306	35,299	47,805	46,617	41,733	44,175	39,204	42,932	45,870	44,675	2%
Texas	22,133	28,967	32,746	34,601	38,240	42,482	47,631	61,286	71,889	81,623	14%
California	53,428	58,881	69,780	56,804	59,332	58,448	59,203	78,654	96,907	84,963	5%
Washington	77,977	74,905	99,832	97,679	86,977	88,571	82,472	88,396	91,007	90,588	2%

Renewable Generation excluding Conventional Hydroelectric

Excluding conventional hydroelectric generation, Michigan generated the 14th most energy from renewables in the country in 2018. Among its peers, only Minnesota and Illinois generated more energy from non-hydro renewables.

Figure 41: 2018 Renewable Generation excluding Hydroelectric

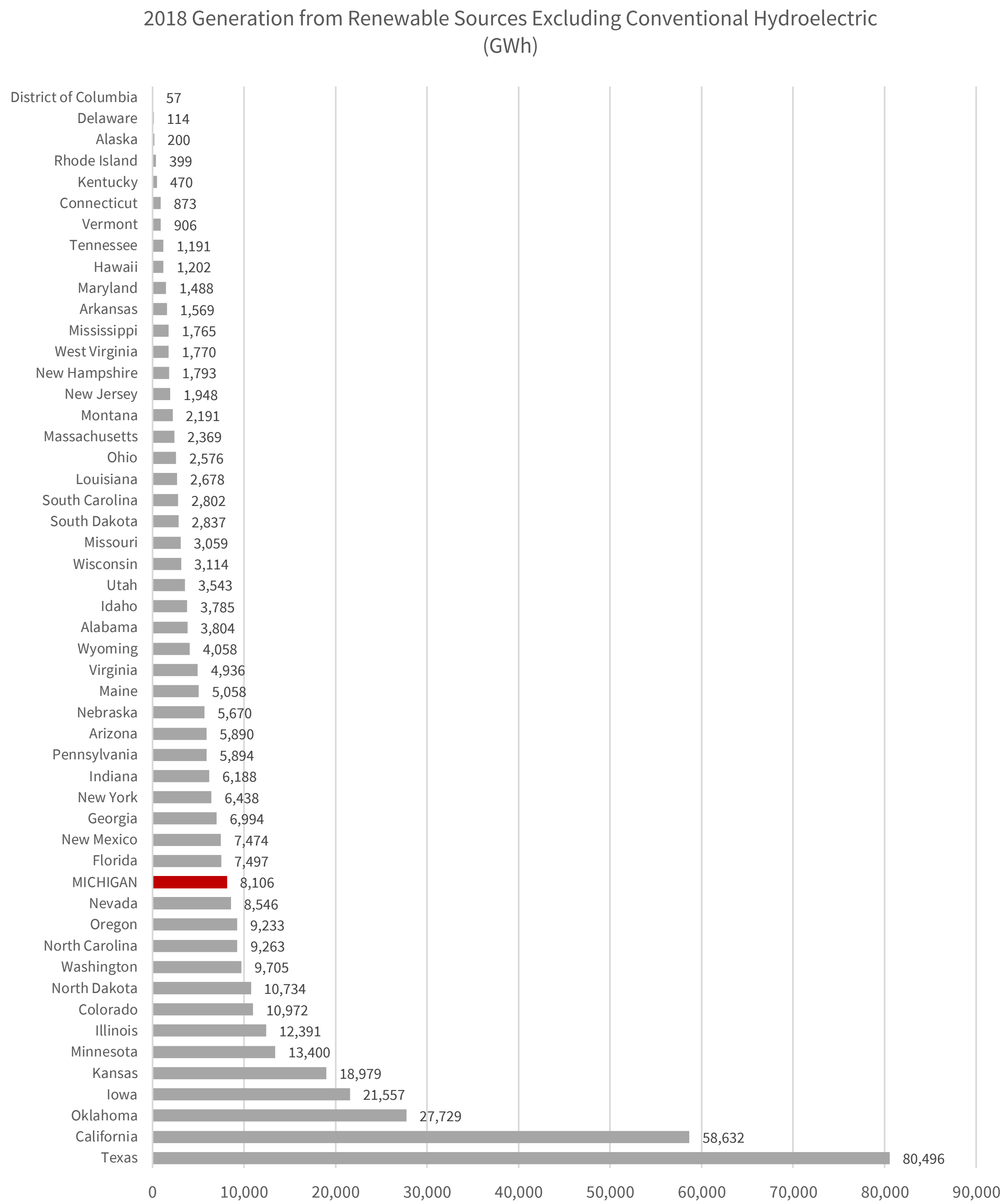


Figure 42: Renewable Generation excluding Hydroelectric

Generation from Renewable Sources Excluding Conventional Hydroelectric (GWh)											
State	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR
District of Columbia	0	0	0	0	0	0	31	53	47	57	
Delaware	126	138	158	131	107	131	130	124	118	114	-1%
Alaska	14	19	16	40	197	214	215	212	185	200	31%
Rhode Island	145	140	130	102	53	226	236	246	366	399	11%
Kentucky	364	440	436	333	327	448	441	477	515	470	3%
Connecticut	759	740	660	667	652	769	805	893	845	873	1%
Vermont	429	482	433	465	745	788	838	828	852	906	8%
Tennessee	950	988	1,020	836	1,110	1,141	1,126	1,050	1,083	1,191	2%
Hawaii	705	747	881	925	1,127	1,206	1,218	1,347	1,322	1,202	5%
Maryland	551	574	822	898	941	989	1,068	1,281	1,365	1,488	10%
Arkansas	1,586	1,624	1,668	1,660	1,601	1,530	1,442	1,396	1,468	1,569	0%
Mississippi	1,424	1,504	1,506	1,509	1,448	1,508	1,507	1,524	1,563	1,765	2%
West Virginia	742	939	1,112	1,297	1,391	1,456	1,381	1,432	1,682	1,770	9%
New Hampshire	1,198	1,232	1,091	1,381	1,695	1,952	2,048	2,122	2,022	1,793	4%
New Jersey	960	850	956	1,281	1,447	1,536	1,595	1,838	1,877	1,948	7%
Montana	916	1,027	1,265	1,262	1,760	1,987	1,986	2,160	2,190	2,191	9%
Massachusetts	1,229	1,274	1,207	1,277	1,448	1,730	1,833	2,030	2,182	2,369	7%
Ohio	633	700	936	1,739	2,009	2,026	2,058	2,033	2,421	2,576	15%
Louisiana	2,364	2,468	2,443	2,430	2,787	2,780	2,705	2,876	2,769	2,678	1%
South Carolina	1,748	1,873	2,129	2,143	2,226	2,442	2,294	2,381	2,479	2,802	5%
South Dakota	427	1,372	2,668	2,354	2,688	2,336	2,498	3,715	2,960	2,837	21%
Missouri	575	988	1,240	1,299	1,241	1,255	1,179	1,293	2,233	3,059	18%
Wisconsin	2,340	2,474	2,765	3,223	3,192	3,262	3,162	2,988	3,122	3,114	3%
Utah	487	781	961	1,100	932	1,256	1,172	2,445	3,628	3,543	22%
Idaho	867	1,014	1,892	2,515	3,152	3,477	2,947	3,212	3,554	3,785	16%
Alabama	3,050	2,377	2,817	2,777	2,876	2,779	3,289	3,367	3,606	3,804	2%
Wyoming	2,226	3,247	4,612	4,369	4,433	4,406	3,757	4,389	4,321	4,058	6%
Virginia	2,418	2,220	2,196	2,358	2,906	3,852	4,144	4,113	4,122	4,936	7%
Maine	3,938	4,152	4,495	4,665	4,893	4,492	4,449	4,455	5,042	5,058	3%
Nebraska	449	493	1,116	1,347	1,869	2,801	3,251	3,900	5,197	5,670	29%
Arizona	202	319	529	1,698	2,733	3,840	4,135	4,522	5,683	5,890	40%
Pennsylvania	3,352	4,245	4,099	4,459	5,754	6,080	5,821	5,942	6,098	5,894	6%
Indiana	1,706	3,246	3,621	3,546	3,888	3,989	5,118	5,558	5,840	6,188	14%
New York	4,467	4,815	4,896	5,192	5,888	6,447	6,319	6,323	6,605	6,438	4%
Georgia	2,825	3,181	3,190	3,279	3,839	4,283	4,863	5,454	7,005	6,994	9%
New Mexico	1,580	1,855	2,242	2,574	2,600	2,813	2,734	4,389	5,818	7,474	17%
Florida	4,340	4,487	4,670	4,524	4,659	5,073	5,143	4,867	5,886	7,497	6%
MICHIGAN	2,623	2,832	2,962	3,785	5,514	6,674	7,283	7,200	7,749	8,106	12%
Nevada	1,808	2,287	2,437	2,969	3,690	4,067	5,103	6,877	7,857	8,546	17%
Oregon	4,272	4,757	5,490	7,207	8,635	8,914	7,950	8,382	7,576	9,233	8%
North Carolina	1,893	2,083	2,345	2,704	2,955	3,276	3,963	5,983	8,397	9,263	17%
Washington	5,045	6,617	8,014	8,214	8,822	9,108	9,067	10,050	8,824	9,705	7%
North Dakota	3,009	4,108	5,245	5,280	5,524	6,205	6,509	8,178	11,361	10,734	14%
Colorado	3,246	3,555	5,367	6,192	7,536	7,747	7,807	10,122	10,435	10,972	13%
Illinois	3,530	5,138	6,865	8,373	10,285	10,699	11,323	11,179	12,794	12,391	13%
Minnesota	6,737	6,640	8,406	10,015	9,871	11,457	11,588	11,836	13,666	13,400	7%
Kansas	2,863	3,459	3,779	5,253	9,491	10,904	11,062	14,172	18,661	18,979	21%
Iowa	7,589	9,360	10,870	14,183	15,727	16,573	18,131	20,324	21,587	21,557	11%
Oklahoma	2,929	4,160	5,919	8,521	11,506	12,275	14,369	20,437	23,930	27,729	25%
California	25,540	25,450	27,222	29,967	35,578	41,917	45,395	49,712	54,544	58,632	9%
Texas	21,104	27,705	32,183	34,017	37,760	42,096	46,674	59,944	70,827	80,496	14%

Renewable Generation as a percent of Total Generation

As a percent of total generation, Michigan performed below average in 2018, generating only 8.35% of its energy from renewables and ranking 20th worst among the states.

Figure 43: 2018 Renewable Generation as a percent of Total Generation

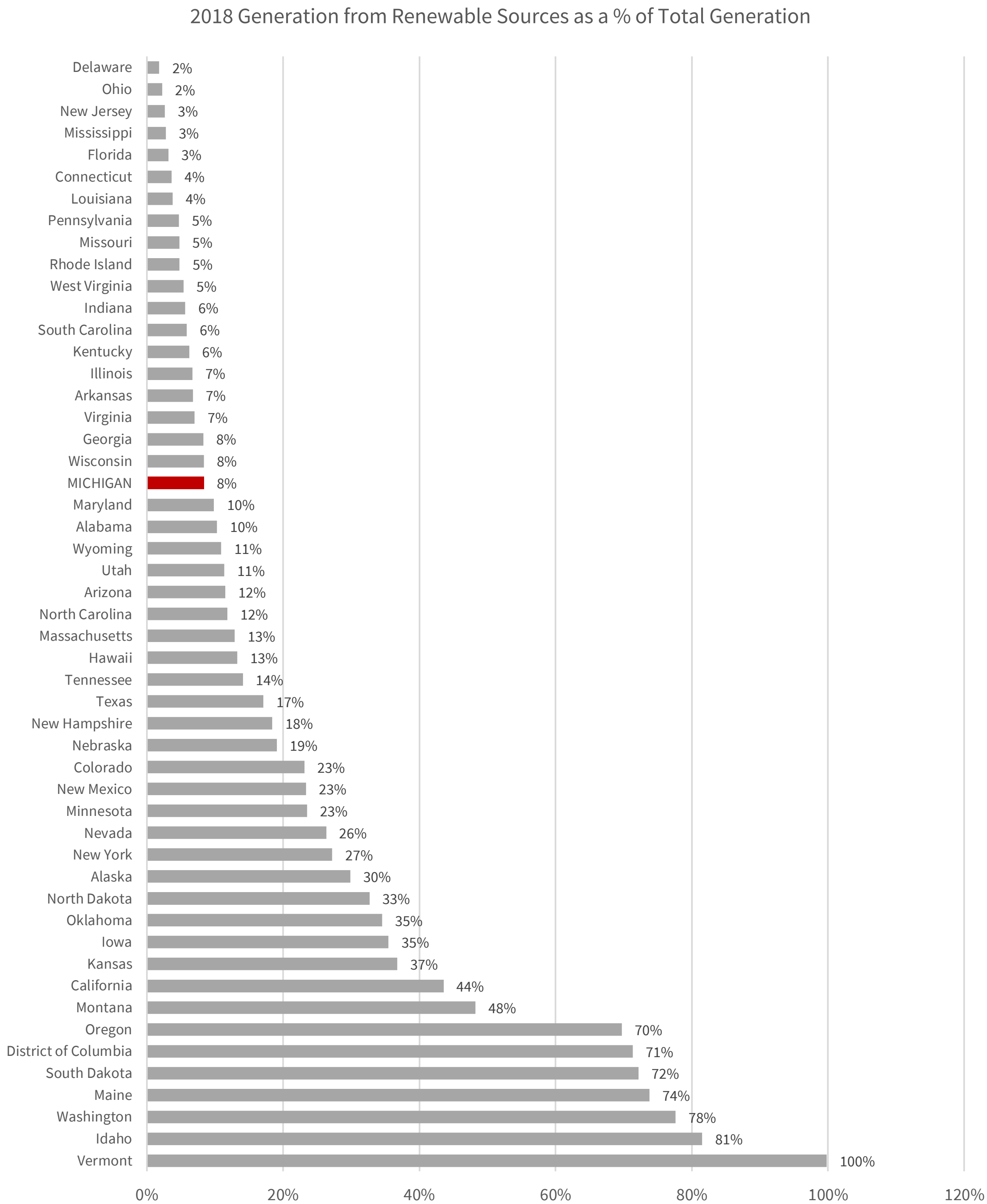


Figure 44: Renewable Generation as a percent of Total Generation

Generation from Renewable Sources as a % of Total Generation											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Delaware	3%	2%	2%	2%	1%	2%	2%	1%	2%	2%	-3%
Ohio	1%	1%	1%	2%	2%	2%	2%	2%	2%	2%	10%
New Jersey	2%	1%	2%	2%	2%	2%	2%	2%	2%	3%	5%
Mississippi	3%	3%	3%	3%	3%	3%	2%	2%	3%	3%	-1%
Florida	2%	2%	2%	2%	2%	2%	2%	2%	3%	3%	4%
Connecticut	4%	3%	4%	3%	3%	4%	3%	3%	3%	4%	-1%
Louisiana	4%	3%	3%	3%	4%	4%	3%	4%	4%	4%	0%
Pennsylvania	3%	3%	3%	3%	4%	4%	4%	4%	4%	5%	6%
Missouri	3%	3%	3%	2%	3%	2%	3%	3%	4%	5%	6%
Rhode Island	2%	2%	2%	1%	1%	4%	3%	4%	5%	5%	9%
West Virginia	3%	3%	3%	4%	4%	3%	4%	4%	5%	5%	5%
Indiana	2%	3%	3%	3%	4%	4%	5%	6%	6%	6%	12%
South Carolina	4%	4%	4%	4%	6%	5%	5%	5%	5%	6%	4%
Kentucky	4%	3%	3%	3%	4%	4%	5%	5%	7%	6%	4%
Illinois	2%	3%	4%	4%	5%	5%	6%	6%	7%	7%	13%
Arkansas	10%	9%	8%	6%	7%	7%	9%	8%	7%	7%	-4%
Virginia	6%	5%	5%	5%	5%	6%	6%	6%	6%	7%	2%
Georgia	5%	5%	5%	5%	6%	6%	6%	7%	7%	8%	6%
Wisconsin	6%	7%	8%	7%	8%	9%	8%	9%	9%	8%	3%
MICHIGAN	4%	4%	4%	5%	7%	8%	8%	8%	8%	8%	8%
Maryland	6%	5%	8%	7%	7%	7%	7%	7%	10%	10%	6%
Alabama	11%	7%	7%	7%	10%	8%	9%	7%	9%	10%	-1%
Wyoming	7%	9%	12%	11%	10%	11%	9%	11%	12%	11%	5%
Utah	3%	3%	5%	5%	3%	4%	5%	8%	13%	11%	14%
Arizona	6%	6%	9%	8%	8%	9%	9%	11%	12%	12%	7%
North Carolina	6%	5%	5%	6%	8%	6%	7%	8%	10%	12%	7%
Massachusetts	6%	5%	6%	6%	7%	8%	8%	9%	10%	13%	8%
Hawaii	7%	8%	9%	10%	12%	13%	13%	14%	14%	13%	6%
Tennessee	14%	11%	13%	12%	17%	13%	14%	10%	12%	14%	0%
Texas	6%	7%	8%	8%	9%	10%	11%	13%	16%	17%	12%
New Hampshire	14%	12%	13%	14%	16%	17%	17%	17%	20%	18%	3%
Nebraska	3%	5%	8%	8%	8%	10%	12%	13%	19%	19%	22%
Colorado	10%	10%	14%	15%	17%	18%	18%	22%	23%	23%	9%
New Mexico	5%	6%	6%	8%	8%	9%	9%	14%	18%	23%	17%
Minnesota	14%	14%	17%	20%	20%	21%	22%	22%	25%	23%	5%
Nevada	11%	13%	14%	15%	17%	18%	19%	22%	25%	26%	9%
New York	24%	22%	24%	22%	23%	24%	23%	25%	29%	27%	1%
Alaska	20%	21%	20%	23%	25%	29%	28%	30%	28%	30%	4%
North Dakota	13%	18%	22%	21%	21%	24%	23%	27%	34%	33%	10%
Oklahoma	9%	10%	10%	12%	19%	20%	22%	29%	35%	35%	15%
Iowa	17%	18%	21%	26%	29%	31%	34%	39%	39%	35%	8%
Kansas	6%	7%	8%	12%	20%	22%	24%	30%	37%	37%	20%
California	26%	29%	35%	28%	30%	29%	30%	40%	47%	44%	5%
Montana	39%	35%	46%	45%	41%	45%	41%	44%	47%	48%	2%
Oregon	66%	64%	80%	77%	70%	73%	68%	71%	73%	70%	1%
District of Columbia							58%	69%	71%	71%	
South Dakota	59%	66%	77%	73%	67%	71%	76%	74%	75%	72%	2%
Maine	50%	47%	53%	56%	60%	61%	67%	65%	75%	74%	4%
Washington	75%	72%	87%	84%	76%	76%	75%	77%	79%	78%	0%
Idaho	86%	85%	92%	87%	77%	82%	75%	78%	82%	81%	-1%
Vermont	26%	28%	27%	24%	29%	28%	100%	100%	100%	100%	14%

Renewable Generation excluding Hydroelectric as a percent of Total Generation

When hydroelectric generation is omitted, Michigan's share of generation from renewables (7.00%) decreased slightly but its ranking among the states climbed to 27th worst.

Figure 45: 2018 Renewable Generation excluding Hydroelectric as a percent of Total Generation

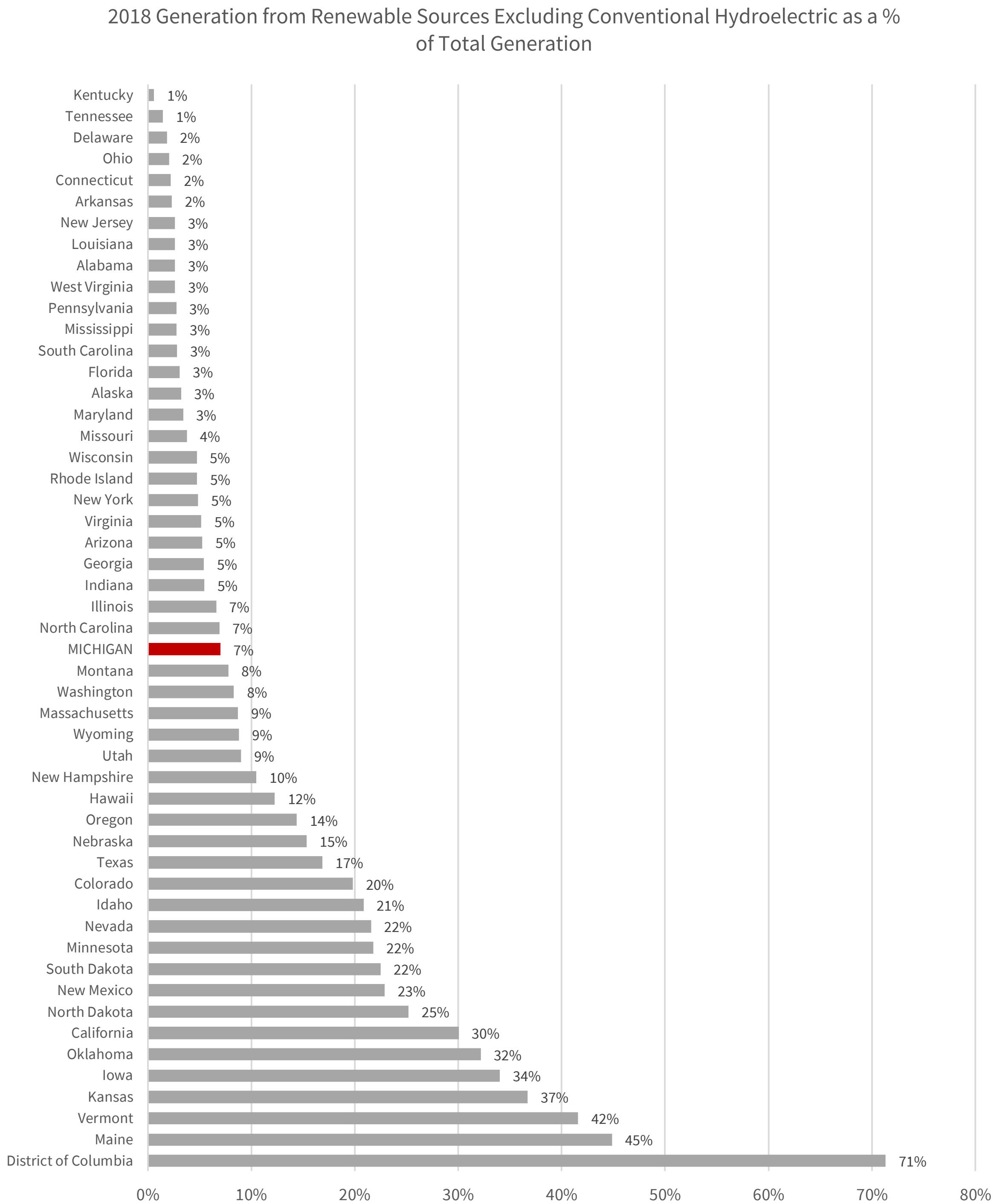


Figure 46: Renewable Generation excluding Hydroelectric as a percent of Total Generation

Generation from Renewable Sources Excluding Conventional Hydroelectric as a % of Total Generation										
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Kentucky	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	4%
Tennessee	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%
Delaware	3%	2%	2%	2%	1%	2%	2%	1%	2%	2%	-3%
Ohio	0%	0%	1%	1%	1%	2%	2%	2%	2%	2%	16%
Connecticut	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	-1%
Arkansas	3%	3%	3%	3%	3%	2%	3%	2%	2%	2%	-2%
New Jersey	2%	1%	1%	2%	2%	2%	2%	2%	2%	3%	5%
Louisiana	3%	2%	2%	2%	3%	3%	3%	3%	3%	3%	0%
Alabama	2%	2%	2%	2%	2%	2%	2%	2%	3%	3%	2%
West Virginia	1%	1%	1%	2%	2%	2%	2%	2%	2%	3%	10%
Pennsylvania	2%	2%	2%	2%	3%	3%	3%	3%	3%	3%	6%
Mississippi	3%	3%	3%	3%	3%	3%	2%	2%	3%	3%	-1%
South Carolina	2%	2%	2%	2%	2%	3%	2%	2%	3%	3%	5%
Florida	2%	2%	2%	2%	2%	2%	2%	2%	2%	3%	4%
Alaska	0%	0%	0%	1%	3%	4%	3%	3%	3%	3%	32%
Maryland	1%	1%	2%	2%	3%	3%	3%	3%	4%	3%	10%
Missouri	1%	1%	1%	1%	1%	1%	1%	2%	3%	4%	19%
Wisconsin	4%	4%	4%	5%	5%	5%	5%	5%	5%	5%	2%
Rhode Island	2%	2%	1%	1%	1%	4%	3%	4%	5%	5%	10%
New York	3%	4%	4%	4%	4%	5%	5%	5%	5%	5%	4%
Virginia	3%	3%	3%	3%	4%	5%	5%	4%	5%	5%	4%
Arizona	0%	0%	0%	2%	2%	3%	4%	4%	5%	5%	40%
Georgia	2%	2%	3%	3%	3%	3%	4%	4%	5%	5%	9%
Indiana	1%	3%	3%	3%	4%	3%	5%	5%	6%	5%	14%
Illinois	2%	3%	3%	4%	5%	5%	6%	6%	7%	7%	14%
North Carolina	2%	2%	2%	2%	2%	3%	3%	5%	7%	7%	16%
MICHIGAN	3%	3%	3%	3%	5%	6%	6%	6%	7%	7%	10%
Montana	3%	3%	4%	5%	6%	7%	7%	8%	8%	8%	9%
Washington	5%	6%	7%	7%	8%	8%	8%	9%	8%	8%	6%
Massachusetts	3%	3%	3%	4%	4%	6%	6%	6%	7%	9%	11%
Wyoming	5%	7%	10%	9%	8%	9%	8%	9%	9%	9%	6%
Utah	1%	2%	2%	3%	2%	3%	3%	6%	10%	9%	23%
New Hampshire	6%	6%	5%	7%	9%	10%	10%	11%	12%	10%	6%
Hawaii	6%	7%	8%	9%	11%	12%	12%	14%	13%	12%	7%
Oregon	8%	9%	9%	12%	14%	15%	14%	14%	12%	14%	7%
Nebraska	1%	1%	3%	4%	5%	7%	8%	11%	15%	15%	28%
Texas	5%	7%	7%	8%	9%	10%	10%	13%	16%	17%	12%
Colorado	6%	7%	10%	12%	14%	14%	15%	19%	19%	20%	12%
Idaho	7%	8%	11%	16%	21%	23%	19%	21%	20%	21%	12%
Nevada	5%	7%	8%	8%	10%	11%	13%	17%	21%	22%	16%
Minnesota	13%	12%	16%	19%	19%	20%	20%	20%	23%	22%	5%
South Dakota	5%	14%	22%	21%	27%	21%	26%	32%	27%	22%	16%
New Mexico	4%	5%	6%	7%	7%	9%	8%	13%	17%	23%	19%
North Dakota	9%	12%	15%	15%	16%	17%	18%	22%	27%	25%	11%
California	12%	12%	14%	15%	18%	21%	23%	25%	26%	30%	9%
Oklahoma	4%	6%	8%	11%	16%	17%	19%	26%	32%	32%	23%
Iowa	15%	16%	19%	25%	28%	29%	32%	37%	37%	34%	9%
Kansas	6%	7%	8%	12%	20%	22%	24%	30%	37%	37%	20%
Vermont	6%	7%	6%	7%	11%	11%	42%	43%	40%	42%	22%
Maine	24%	24%	28%	31%	35%	34%	38%	39%	45%	45%	6%
District of Columbia							58%	69%	71%	71%	

Renewable Generation as a percent of Total Sales

Michigan's renewable generation as a percent of total sales was 9.23% in 2018. This was the 21st lowest percentage among the states in 2018.

Figure 47: 2018 Renewable Generation as a percent of Total Sales

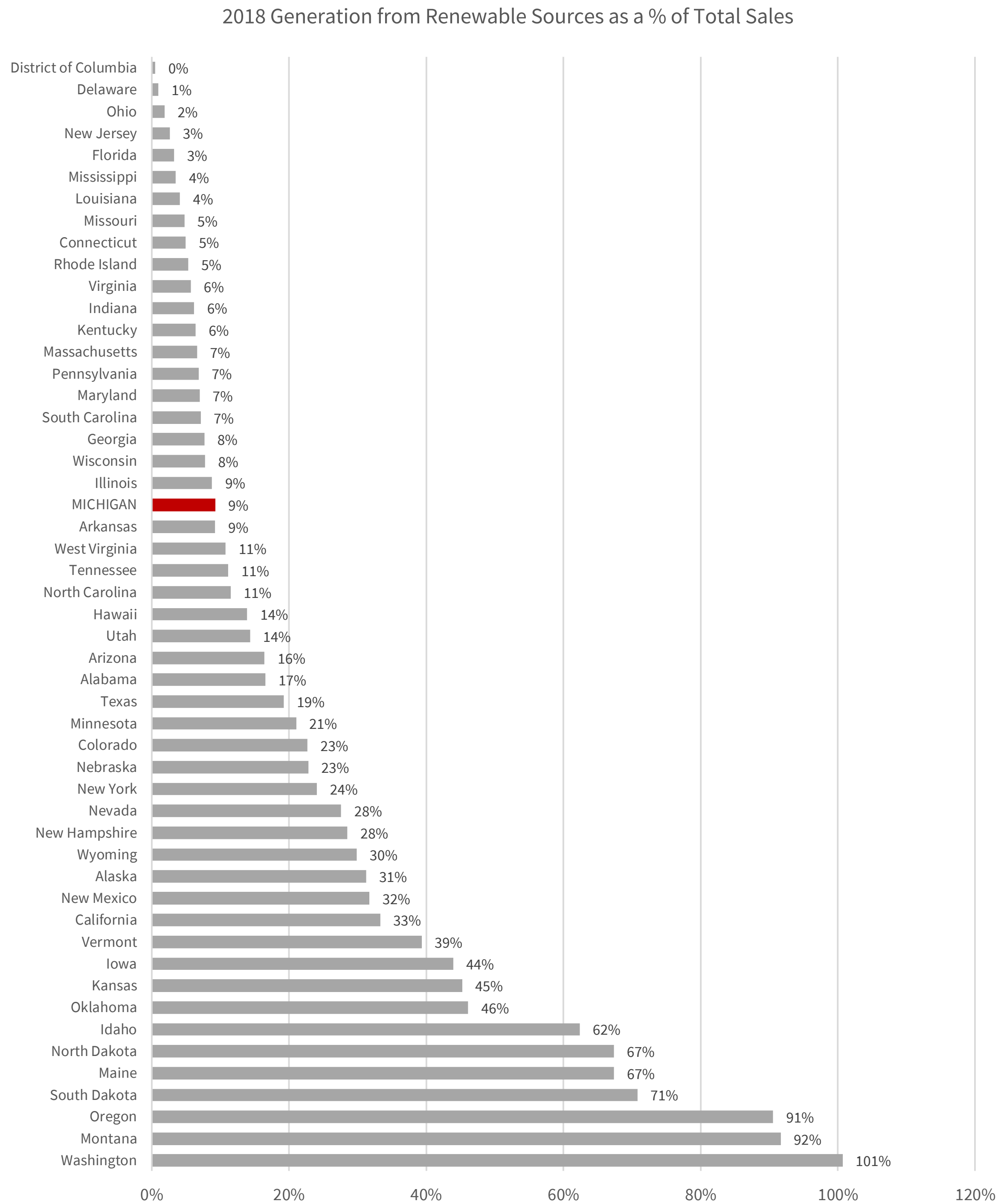


Figure 48: Renewable Generation as a percent of Total Sales

Generation from Renewable Sources as a % of Total Sales											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
District of Columbia							0%	0%	0%	0%	
Delaware	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	-1%
Ohio	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%	9%
New Jersey	1%	1%	1%	2%	2%	2%	2%	2%	3%	3%	7%
Florida	2%	2%	2%	2%	2%	2%	2%	2%	3%	3%	5%
Mississippi	3%	3%	3%	3%	3%	3%	3%	3%	3%	4%	1%
Louisiana	5%	4%	4%	4%	4%	4%	4%	4%	4%	4%	-1%
Missouri	3%	3%	3%	2%	3%	2%	3%	3%	4%	5%	5%
Connecticut	4%	4%	4%	3%	4%	4%	4%	4%	4%	5%	2%
Rhode Island	2%	2%	2%	1%	1%	3%	3%	3%	5%	5%	10%
Virginia	4%	3%	3%	3%	4%	4%	5%	5%	5%	6%	5%
Indiana	2%	3%	4%	4%	4%	4%	5%	6%	6%	6%	11%
Kentucky	4%	3%	4%	3%	4%	5%	5%	5%	7%	6%	4%
Massachusetts	4%	4%	4%	4%	4%	5%	5%	5%	6%	7%	4%
Pennsylvania	4%	4%	5%	5%	6%	6%	6%	6%	6%	7%	5%
Maryland	4%	3%	5%	4%	4%	4%	4%	4%	6%	7%	6%
South Carolina	5%	5%	5%	5%	7%	6%	6%	6%	6%	7%	3%
Georgia	5%	5%	4%	4%	6%	5%	6%	6%	7%	8%	5%
Wisconsin	6%	7%	7%	7%	7%	8%	8%	8%	8%	8%	3%
Illinois	3%	4%	5%	6%	7%	8%	8%	8%	9%	9%	13%
MICHIGAN	4%	4%	4%	5%	7%	8%	9%	8%	9%	9%	9%
Arkansas	13%	11%	10%	8%	9%	9%	11%	11%	10%	9%	-4%
West Virginia	8%	7%	8%	9%	10%	8%	9%	10%	11%	11%	3%
Tennessee	12%	9%	11%	9%	14%	10%	11%	8%	10%	11%	-1%
North Carolina	6%	5%	5%	5%	8%	6%	7%	8%	9%	11%	8%
Hawaii	8%	8%	10%	11%	13%	14%	14%	15%	15%	14%	6%
Utah	5%	5%	8%	6%	5%	6%	6%	11%	16%	14%	12%
Arizona	9%	10%	13%	11%	11%	13%	14%	15%	16%	16%	6%
Alabama	19%	12%	13%	12%	18%	14%	15%	12%	15%	17%	-1%
Texas	6%	8%	9%	9%	10%	11%	12%	15%	18%	19%	12%
Minnesota	12%	11%	13%	16%	15%	17%	19%	20%	22%	21%	6%
Colorado	10%	10%	14%	14%	16%	18%	17%	22%	22%	23%	8%
Nebraska	3%	6%	9%	8%	10%	13%	17%	16%	22%	23%	22%
New York	23%	21%	23%	21%	21%	22%	22%	22%	25%	24%	0%
Nevada	12%	13%	14%	15%	18%	18%	20%	24%	26%	28%	8%
New Hampshire	27%	25%	25%	24%	28%	30%	30%	30%	32%	28%	1%
Wyoming	19%	25%	34%	31%	30%	31%	27%	32%	32%	30%	4%
Alaska	21%	23%	22%	25%	26%	28%	29%	31%	30%	31%	4%
New Mexico	9%	9%	11%	12%	12%	13%	12%	20%	26%	32%	14%
California	21%	23%	27%	22%	23%	22%	23%	31%	38%	33%	5%
Vermont	35%	33%	33%	29%	36%	35%	36%	35%	39%	39%	1%
Iowa	20%	23%	26%	33%	35%	37%	40%	44%	46%	44%	8%
Kansas	8%	9%	9%	13%	24%	27%	28%	35%	46%	45%	20%
Oklahoma	12%	12%	12%	16%	23%	22%	28%	37%	43%	46%	15%
Idaho	50%	45%	66%	57%	48%	54%	51%	53%	60%	62%	2%
North Dakota	35%	47%	57%	53%	46%	48%	47%	54%	69%	67%	7%
Maine	72%	69%	74%	73%	71%	68%	66%	65%	75%	67%	-1%
South Dakota	44%	58%	79%	71%	55%	63%	61%	70%	67%	71%	5%
Oregon	78%	77%	101%	100%	88%	93%	83%	91%	92%	91%	1%
Montana	73%	76%	101%	90%	81%	96%	84%	87%	89%	92%	2%
Washington	86%	83%	107%	106%	94%	96%	92%	99%	99%	101%	2%

Renewable Generation excluding Hydroelectric as a percent of Total Sales

Excluding hydroelectric, Michigan's 7.73% of renewable generation compared to total sales ranked 28th worst among the states in 2018.

Figure 49: 2018 Renewable Generation excluding Hydroelectric as a percent of Total Sales

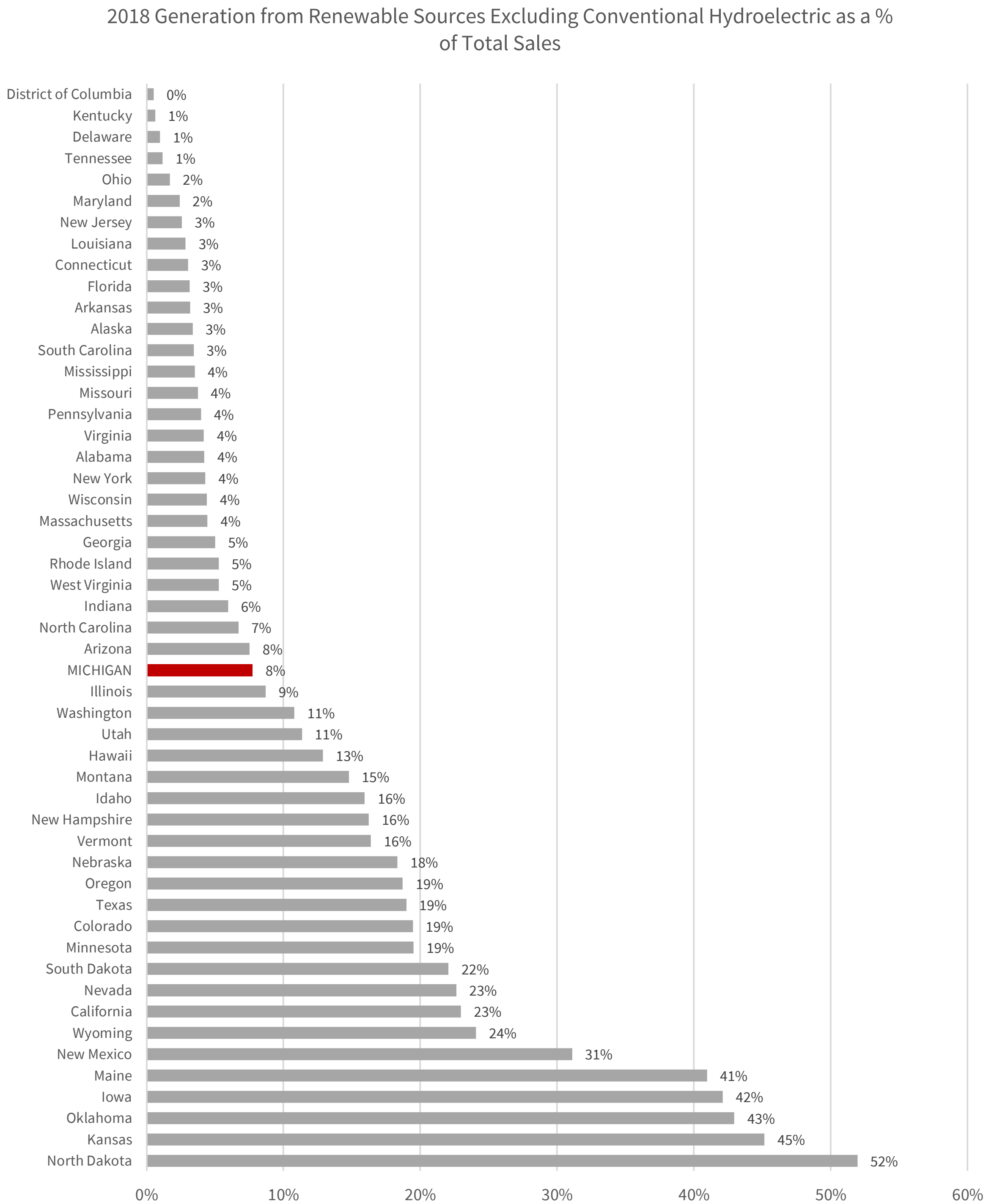


Figure 50: Renewable Generation excluding Hydroelectric as a percent of Total Sales

Generation from Renewable Sources Excluding Conventional Hydroelectric as a % of Total Sales											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
District of Columbia							0%	0%	0%	0%	
Kentucky	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	4%
Delaware	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	-1%
Tennessee	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Ohio	0%	0%	1%	1%	1%	1%	1%	1%	2%	2%	15%
Maryland	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%	11%
New Jersey	1%	1%	1%	2%	2%	2%	2%	2%	3%	3%	7%
Louisiana	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	-1%
Connecticut	3%	2%	2%	2%	2%	3%	3%	3%	3%	3%	2%
Florida	2%	2%	2%	2%	2%	2%	2%	2%	3%	3%	5%
Arkansas	4%	3%	3%	4%	3%	3%	3%	3%	3%	3%	-1%
Alaska	0%	0%	0%	1%	3%	3%	3%	3%	3%	3%	32%
South Carolina	2%	2%	3%	3%	3%	3%	3%	3%	3%	3%	4%
Mississippi	3%	3%	3%	3%	3%	3%	3%	3%	3%	4%	1%
Missouri	1%	1%	1%	2%	1%	1%	1%	2%	3%	4%	18%
Pennsylvania	2%	3%	3%	3%	4%	4%	4%	4%	4%	4%	5%
Virginia	2%	2%	2%	2%	3%	3%	4%	4%	4%	4%	6%
Alabama	4%	3%	3%	3%	3%	3%	4%	4%	4%	4%	1%
New York	3%	3%	3%	4%	4%	4%	4%	4%	5%	4%	3%
Wisconsin	4%	4%	4%	5%	5%	5%	5%	4%	5%	4%	2%
Massachusetts	2%	2%	2%	2%	3%	3%	3%	4%	4%	4%	7%
Georgia	2%	2%	2%	3%	3%	3%	4%	4%	5%	5%	9%
Rhode Island	2%	2%	2%	1%	1%	3%	3%	3%	5%	5%	11%
West Virginia	2%	3%	4%	4%	4%	4%	4%	4%	5%	5%	8%
Indiana	2%	3%	3%	3%	4%	4%	5%	5%	6%	6%	13%
North Carolina	1%	2%	2%	2%	2%	2%	3%	4%	6%	7%	16%
Arizona	0%	0%	1%	2%	4%	5%	5%	6%	7%	8%	39%
MICHIGAN	3%	3%	3%	4%	5%	6%	7%	7%	8%	8%	11%
Illinois	3%	4%	5%	6%	7%	8%	8%	8%	9%	9%	13%
Washington	6%	7%	9%	9%	9%	10%	10%	11%	10%	11%	7%
Utah	2%	3%	3%	4%	3%	4%	4%	8%	12%	11%	20%
Hawaii	7%	7%	9%	10%	12%	13%	13%	14%	14%	13%	6%
Montana	6%	7%	9%	9%	13%	14%	14%	15%	15%	15%	9%
Idaho	4%	4%	8%	11%	13%	15%	13%	14%	15%	16%	15%
New Hampshire	11%	11%	10%	13%	15%	18%	19%	19%	19%	16%	4%
Vermont	8%	9%	8%	8%	13%	14%	15%	15%	16%	16%	8%
Nebraska	2%	2%	4%	4%	6%	9%	11%	13%	17%	18%	28%
Oregon	9%	10%	12%	15%	18%	19%	17%	18%	15%	19%	8%
Texas	6%	8%	9%	9%	10%	11%	12%	15%	18%	19%	12%
Colorado	6%	7%	10%	12%	14%	15%	14%	18%	19%	19%	12%
Minnesota	11%	10%	12%	15%	14%	17%	17%	18%	20%	19%	6%
South Dakota	4%	12%	23%	20%	22%	19%	21%	31%	24%	22%	19%
Nevada	5%	7%	7%	8%	10%	12%	14%	19%	21%	23%	16%
California	10%	10%	10%	12%	14%	16%	17%	19%	21%	23%	9%
Wyoming	13%	19%	26%	26%	26%	26%	22%	27%	26%	24%	6%
New Mexico	7%	8%	10%	11%	11%	12%	12%	19%	25%	31%	16%
Maine	35%	36%	39%	40%	41%	37%	37%	39%	45%	41%	2%
Iowa	17%	21%	24%	31%	34%	35%	38%	42%	44%	42%	9%
Oklahoma	5%	7%	10%	14%	19%	20%	23%	33%	40%	43%	23%
Kansas	7%	9%	9%	13%	24%	27%	28%	35%	46%	45%	20%
North Dakota	24%	32%	38%	36%	34%	34%	36%	44%	56%	52%	8%

Renewable and Carbon-free Generation

When other carbon-free generation (nuclear) is added to renewable generation, Michigan's ranking improves. Michigan's generation from renewable and carbon-free sources ranked 38th lowest in the country, with only Illinois ranking higher among its peer group.

Figure 51: 2018 Renewable and Carbon-free Generation

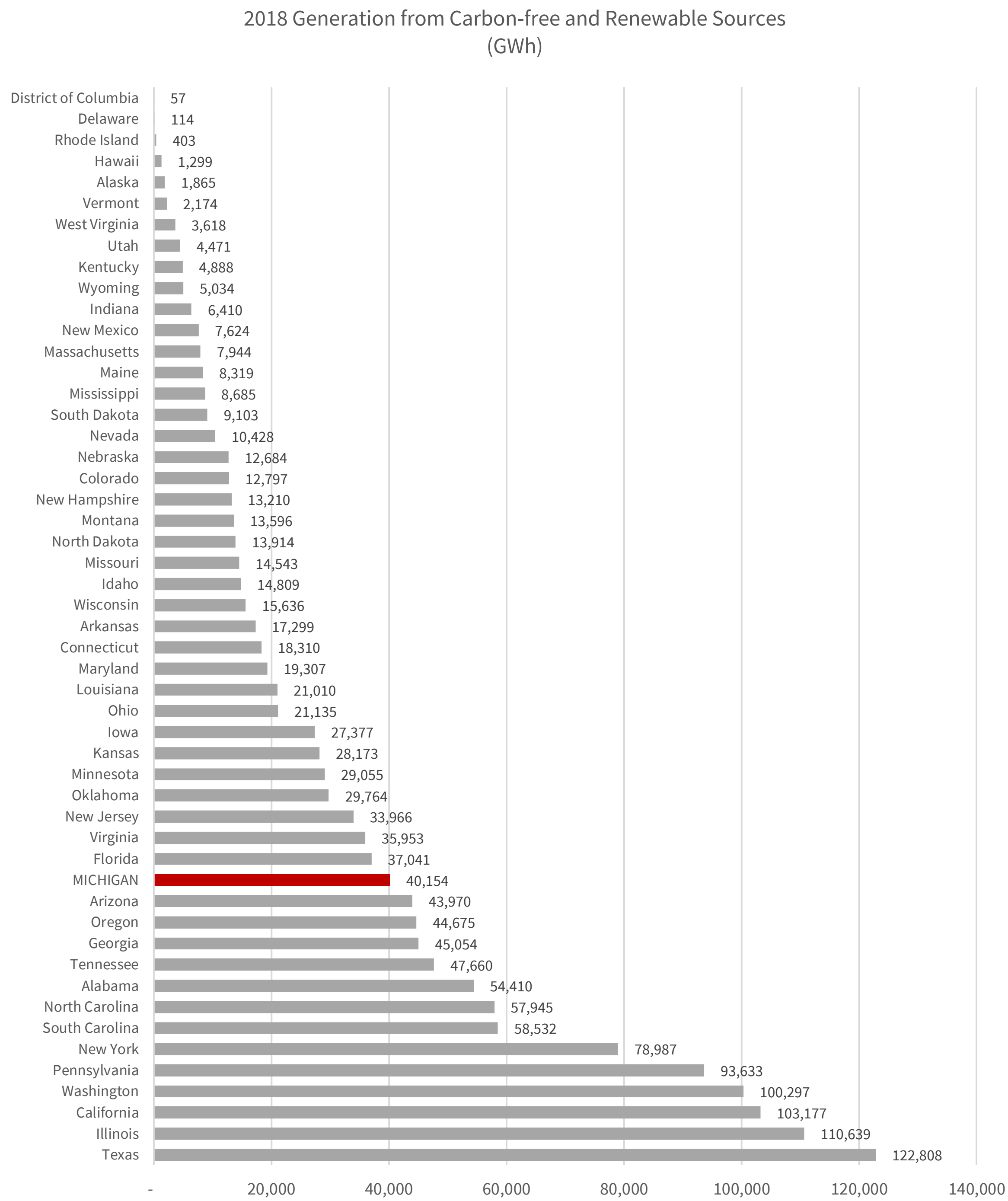


Figure 52: Renewable and Carbon-free Generation

Generation from Carbon-free and Renewable Sources (GWh)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
District of Columbia	-	-	-	-	-	-	31	53	47	57	
Delaware	126	138	158	131	107	131	130	124	118	114	-1%
Rhode Island	149	144	138	106	57	230	239	248	368	403	10%
Hawaii	817	817	974	1,039	1,205	1,300	1,340	1,438	1,388	1,299	5%
Alaska	1,337	1,452	1,360	1,615	1,633	1,753	1,784	1,871	1,829	1,865	3%
Vermont	7,275	6,612	6,765	6,606	6,877	7,023	1,977	1,905	2,132	2,174	-11%
West Virginia	2,388	2,307	2,565	2,728	3,129	2,698	2,766	3,070	3,341	3,618	4%
Utah	1,322	1,476	2,191	1,848	1,437	1,889	1,941	3,205	4,922	4,471	13%
Kentucky	3,681	3,020	3,406	2,695	3,602	3,592	3,845	3,955	5,021	4,888	3%
Wyoming	3,193	4,271	5,836	5,263	5,144	5,274	4,625	5,363	5,444	5,034	5%
Indiana	2,209	3,699	4,030	3,980	4,275	4,360	5,499	5,984	6,147	6,410	11%
New Mexico	1,851	2,072	2,436	2,797	2,692	2,911	2,834	4,537	6,011	7,624	15%
Massachusetts	7,826	8,188	7,441	8,049	6,771	8,401	7,655	8,156	8,266	7,944	0%
Maine	8,150	7,963	8,474	8,398	8,454	8,115	7,809	7,455	8,431	8,319	0%
Mississippi	12,423	11,148	11,843	8,805	12,313	11,760	13,221	7,421	8,928	8,685	-4%
South Dakota	4,859	6,611	9,276	8,335	6,750	7,835	7,348	8,520	8,216	9,103	6%
Nevada	4,269	4,444	4,628	5,409	6,372	6,456	7,367	8,666	9,669	10,428	9%
Nebraska	10,318	12,861	9,667	8,405	9,858	14,061	15,261	14,107	13,598	12,684	2%
Colorado	5,132	5,133	7,449	7,689	8,749	9,517	9,427	12,024	12,332	12,797	10%
New Hampshire	11,695	13,620	11,059	10,818	14,049	13,502	12,802	14,028	13,426	13,210	1%
Montana	10,422	10,442	13,861	12,545	11,398	13,470	11,874	12,243	13,136	13,596	3%
North Dakota	4,484	6,150	7,825	7,757	7,377	8,736	8,603	10,090	13,943	13,914	12%
Missouri	12,639	11,523	11,797	12,731	10,744	11,229	13,214	11,992	11,718	14,543	1%
Idaho	11,302	10,168	15,297	13,455	11,626	12,479	11,704	12,245	14,224	14,809	3%
Wisconsin	16,417	17,867	16,472	19,053	16,846	15,181	15,511	15,934	15,428	15,636	0%
Arkansas	20,948	20,306	18,820	19,352	16,201	18,648	18,849	18,387	17,102	17,299	-2%
Connecticut	17,926	17,881	17,155	18,057	18,134	17,043	18,518	17,693	17,677	18,310	0%
Maryland	16,990	16,235	17,766	16,134	16,932	16,948	17,334	17,434	18,437	19,307	1%
Louisiana	20,382	22,216	20,102	18,769	20,786	21,181	19,005	21,131	19,085	21,010	0%
Ohio	16,367	16,934	16,209	19,240	18,680	18,788	19,891	19,351	20,386	21,135	3%
Iowa	13,239	14,759	17,010	19,297	21,797	21,604	24,334	25,943	27,835	27,377	8%
Kansas	11,645	13,028	11,112	13,548	16,674	19,479	19,711	22,448	29,338	28,173	9%
Minnesota	19,939	20,958	21,111	22,519	21,090	24,712	24,475	26,905	28,828	29,055	4%
Oklahoma	6,482	6,969	7,426	9,666	13,684	13,704	17,033	23,010	25,966	29,764	16%
New Jersey	35,320	33,639	34,586	34,402	34,845	33,060	34,866	31,733	35,924	33,966	0%
Virginia	32,108	30,292	28,954	32,126	33,486	35,028	33,363	35,316	35,792	35,953	1%
Florida	33,666	28,600	26,868	22,544	31,439	33,153	33,510	34,362	35,250	37,041	1%
MICHIGAN	25,846	33,708	37,209	33,012	35,854	39,520	38,116	40,316	41,809	40,154	5%
Arizona	37,292	38,141	40,981	40,349	40,078	42,280	43,197	44,067	44,855	43,970	2%
Oregon	37,306	35,299	47,805	46,617	41,733	44,175	39,204	42,932	45,870	44,675	2%
Georgia	37,767	40,014	38,201	39,456	40,456	39,917	41,685	43,308	43,123	45,054	2%
Tennessee	38,124	36,865	37,515	34,234	42,047	37,712	35,668	37,402	41,592	47,660	2%
Alabama	55,301	49,022	51,056	51,053	56,591	53,490	55,102	50,253	55,496	54,410	0%
North Carolina	47,912	47,579	46,766	45,817	50,097	48,999	50,802	53,187	54,590	57,945	2%
South Carolina	56,230	56,238	56,586	54,709	59,638	57,430	58,014	60,433	58,659	58,532	0%
New York	75,567	72,156	75,588	70,619	75,617	75,572	76,936	74,783	78,917	78,987	0%
Pennsylvania	83,362	84,406	83,463	81,875	86,993	87,436	88,941	91,241	92,421	93,633	1%
Washington	84,611	84,146	104,638	107,012	95,438	98,069	90,633	98,022	99,135	100,297	2%
California	85,192	91,081	106,443	75,312	77,244	75,434	77,709	97,562	114,808	103,177	2%
Illinois	99,140	101,446	102,829	104,885	107,537	108,690	108,730	109,919	110,110	110,639	1%
Texas	63,631	70,302	72,395	73,042	76,555	81,769	86,985	103,366	110,471	122,808	

Carbon-free Generation

When only carbon-free generation sources are included, Michigan ranked 38th lowest among all states in 2018.

Figure 53: 2018 Carbon-free Generation

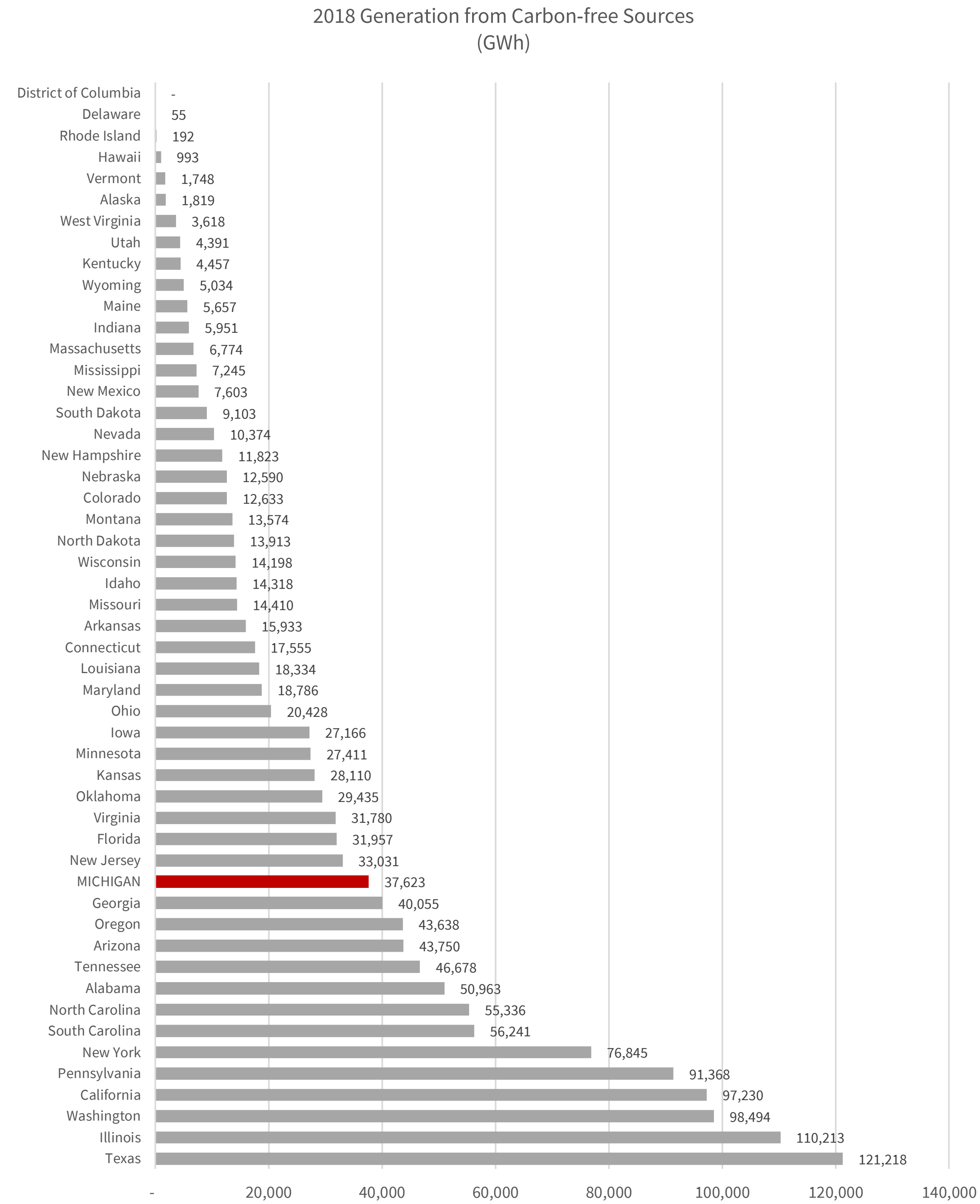


Figure 54: Carbon-free Generation

Generation from Carbon-free Sources (GWh)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
District of Columbia	-	-	-	-	-	-	-	-	-	-	
Delaware	-	3	13	26	49	55	54	56	55	55	
Rhode Island	5	7	10	6	9	24	28	43	165	192	45%
Hawaii	533	534	661	758	876	966	1,019	1,079	1,095	993	6%
Vermont	6,858	6,143	6,367	6,253	6,386	6,571	1,513	1,428	1,685	1,748	-13%
Alaska	1,331	1,446	1,357	1,612	1,581	1,691	1,729	1,828	1,785	1,819	3%
West Virginia	2,388	2,307	2,556	2,717	3,125	2,693	2,761	3,070	3,341	3,618	4%
Utah	1,274	1,420	2,133	1,788	1,366	1,817	1,856	3,121	4,844	4,391	13%
Kentucky	3,318	2,580	2,969	2,362	3,275	3,144	3,403	3,490	4,526	4,457	3%
Wyoming	3,193	4,271	5,836	5,263	5,144	5,274	4,625	5,363	5,444	5,034	5%
Maine	4,510	4,310	4,686	4,620	4,608	4,721	4,656	4,667	5,727	5,657	2%
Indiana	1,907	3,388	3,694	3,644	3,899	3,969	5,052	5,552	5,673	5,951	12%
Massachusetts	6,603	6,937	6,300	6,891	5,634	7,203	6,488	6,952	7,106	6,774	0%
Mississippi	10,999	9,643	10,337	7,296	10,865	10,252	11,715	5,897	7,451	7,245	-4%
New Mexico	1,818	2,058	2,427	2,782	2,673	2,897	2,814	4,519	5,993	7,603	15%
South Dakota	4,853	6,611	9,276	8,335	6,750	7,835	7,348	8,520	8,216	9,103	6%
Nevada	4,268	4,444	4,628	5,390	6,348	6,432	7,342	8,611	9,612	10,374	9%
New Hampshire	10,560	12,463	10,034	9,645	12,743	11,961	11,178	12,339	11,816	11,823	1%
Nebraska	10,251	12,790	9,601	8,342	9,791	13,997	15,190	14,009	13,501	12,590	2%
Colorado	5,075	5,073	7,388	7,631	8,665	9,391	9,347	11,862	12,166	12,633	10%
Montana	10,327	10,345	13,861	12,545	11,393	13,457	11,852	12,223	13,115	13,574	3%
North Dakota	4,473	6,138	7,816	7,752	7,371	8,734	8,600	10,084	13,941	13,913	12%
Wisconsin	15,129	16,481	14,894	17,387	15,212	13,538	13,940	14,465	13,969	14,198	-1%
Idaho	10,824	9,667	14,775	12,906	10,973	11,887	11,102	11,713	13,759	14,318	3%
Missouri	12,563	11,461	11,735	12,677	10,670	11,114	13,085	11,853	11,574	14,410	1%
Arkansas	19,363	18,682	17,152	17,692	14,600	17,118	17,408	17,017	15,665	15,933	-2%
Connecticut	17,167	17,141	16,495	17,390	17,482	16,286	17,731	16,837	16,884	17,555	0%
Louisiana	18,018	19,748	17,659	16,339	17,999	18,401	16,300	18,255	16,318	18,334	0%
Maryland	16,439	15,663	17,218	15,580	16,376	16,381	16,820	16,888	17,901	18,786	1%
Ohio	15,748	16,259	15,487	18,523	17,863	17,970	19,092	18,629	19,659	20,428	3%
Iowa	13,071	14,569	16,850	19,146	21,638	21,338	24,076	25,692	27,625	27,166	8%
Minnesota	18,256	19,110	19,430	20,681	19,480	22,949	22,669	25,013	26,895	27,411	4%
Kansas	11,645	12,974	11,054	13,491	16,616	19,419	19,649	22,390	29,281	28,110	9%
Oklahoma	6,251	6,617	7,112	9,303	13,341	13,365	16,696	22,648	25,668	29,435	17%
Virginia	29,691	28,072	26,758	29,767	30,580	31,176	29,219	31,224	31,983	31,780	1%
Florida	29,336	24,194	22,323	18,214	26,990	28,321	28,590	29,719	30,241	31,957	1%
New Jersey	34,392	32,823	33,710	33,437	33,846	32,062	33,921	30,750	34,995	33,031	0%
MICHIGAN	23,523	31,235	34,703	30,358	33,139	36,714	35,631	37,821	39,315	37,623	5%
Georgia	34,942	36,834	35,011	36,181	36,631	35,754	36,951	38,734	38,105	40,055	1%
Oregon	36,503	34,462	47,090	45,786	40,739	43,025	38,088	41,931	44,889	43,638	2%
Arizona	37,133	37,973	40,791	40,138	39,907	42,049	42,970	43,853	44,684	43,750	2%
Tennessee	37,226	35,918	36,548	33,457	41,004	36,649	34,664	36,469	40,644	46,678	2%
Alabama	52,252	46,645	48,240	48,276	53,715	50,711	51,813	46,918	52,070	50,963	0%
North Carolina	46,024	45,507	44,438	43,253	47,487	46,452	48,212	50,631	51,777	55,336	2%
South Carolina	54,482	54,365	54,457	52,566	57,412	54,992	55,725	58,057	56,259	56,241	0%
New York	73,366	69,937	73,527	68,471	73,335	73,165	74,695	72,539	76,631	76,845	0%
Pennsylvania	81,089	82,022	81,181	79,577	84,654	84,983	86,537	88,850	89,983	91,368	1%
California	78,992	85,080	100,414	69,000	70,609	68,543	71,241	91,623	109,000	97,230	2%
Washington	83,139	82,274	102,887	105,399	93,621	96,229	88,642	96,014	97,237	98,494	2%
Illinois	98,430	100,776	102,191	104,270	106,929	108,123	108,203	109,452	109,636	110,213	1%
Texas	62,552	68,857	70,788	71,358	74,832	79,961	85,545	101,683	108,894	121,218	7%

Renewable and Carbon-free Generation as a percent of Total Generation

In 2018, Michigan produced 34.7% of its total generation from carbon-free and renewable sources, ranking 25th lowest among the states with Minnesota and Illinois performing better among its peer group. This metric has increased about 3% per year on average, making Michigan 32nd lowest in terms of growth.

Figure 55: 2018 Carbon-free and Renewable Generation as a percent of Total Generation

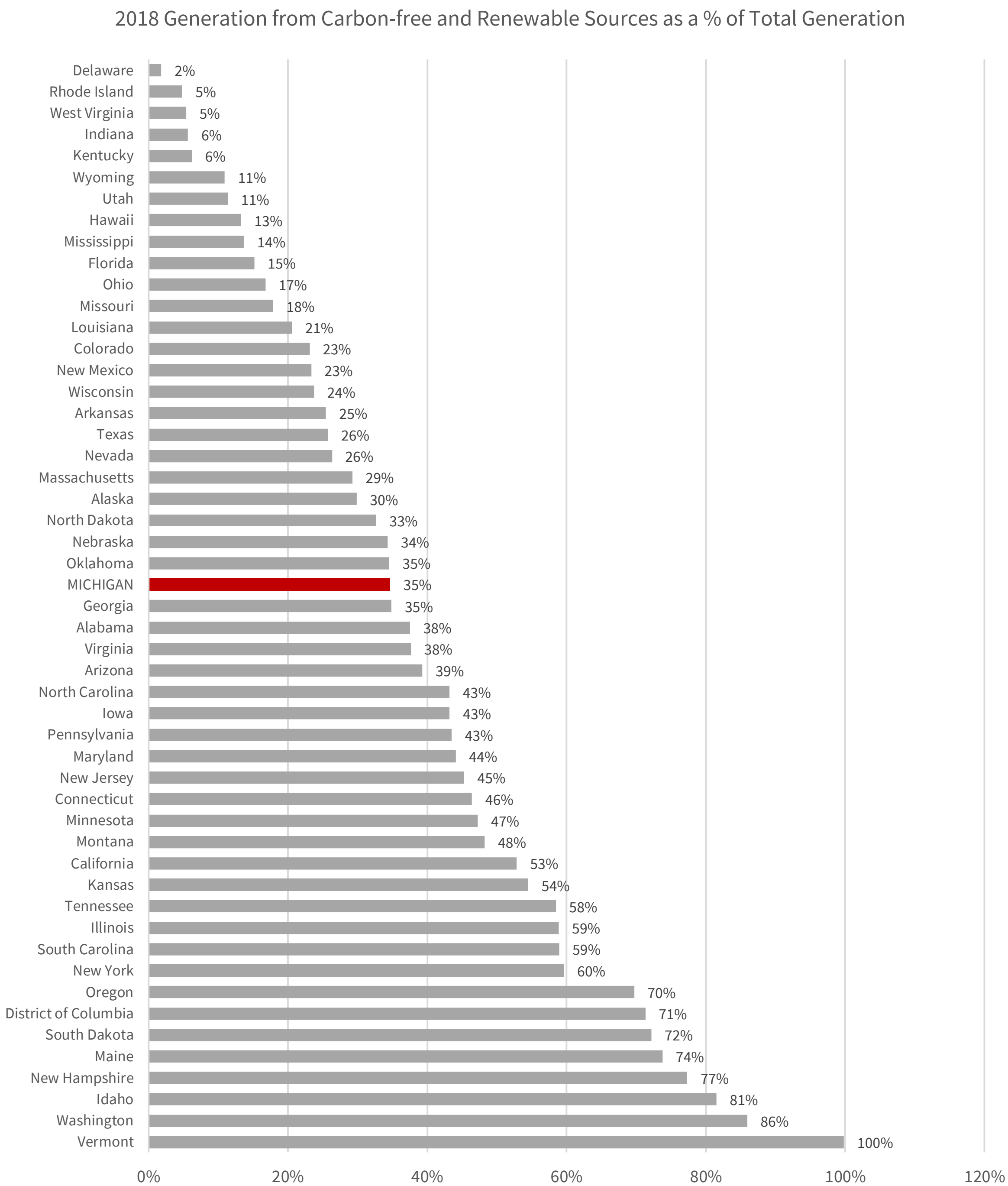


Figure 56: Carbon-free and Renewable Generation as a percent of Total Generation

Generation from Carbon-free and Renewable Sources as a % of Total Generation											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Delaware	3%	2%	2%	2%	1%	2%	2%	1%	2%	2%	-3%
Rhode Island	2%	2%	2%	1%	1%	4%	3%	4%	5%	5%	9%
West Virginia	3%	3%	3%	4%	4%	3%	4%	4%	5%	5%	5%
Indiana	2%	3%	3%	3%	4%	4%	5%	6%	6%	6%	12%
Kentucky	4%	3%	3%	3%	4%	4%	5%	5%	7%	6%	4%
Wyoming	7%	9%	12%	11%	10%	11%	9%	11%	12%	11%	5%
Utah	3%	3%	5%	5%	3%	4%	5%	8%	13%	11%	14%
Hawaii	7%	8%	9%	10%	12%	13%	13%	14%	14%	13%	6%
Mississippi	26%	20%	23%	16%	23%	21%	20%	12%	15%	14%	-6%
Florida	15%	12%	12%	10%	14%	14%	14%	14%	15%	15%	0%
Ohio	12%	12%	12%	15%	14%	14%	16%	16%	17%	17%	3%
Missouri	14%	12%	12%	14%	12%	13%	16%	15%	14%	18%	2%
Louisiana	22%	22%	19%	18%	20%	20%	18%	20%	20%	21%	-1%
Colorado	10%	10%	14%	15%	17%	18%	18%	22%	23%	23%	9%
New Mexico	5%	6%	6%	8%	8%	9%	9%	14%	18%	23%	17%
Wisconsin	27%	28%	26%	30%	26%	25%	23%	25%	24%	24%	-1%
Arkansas	36%	33%	31%	30%	27%	30%	34%	30%	28%	25%	-4%
Texas	16%	17%	17%	17%	18%	19%	19%	23%	24%	26%	5%
Nevada	11%	13%	14%	15%	17%	18%	19%	22%	25%	26%	9%
Massachusetts	20%	19%	20%	23%	21%	27%	24%	26%	26%	29%	4%
Alaska	20%	21%	20%	23%	25%	29%	28%	30%	28%	30%	4%
North Dakota	13%	18%	22%	21%	21%	24%	23%	27%	34%	33%	10%
Nebraska	30%	35%	27%	25%	27%	36%	38%	39%	38%	34%	1%
Oklahoma	9%	10%	10%	12%	19%	20%	22%	29%	35%	35%	15%
MICHIGAN	26%	30%	34%	31%	34%	37%	34%	36%	37%	35%	3%
Georgia	29%	29%	31%	32%	33%	32%	32%	32%	34%	35%	2%
Alabama	39%	32%	33%	33%	38%	36%	36%	35%	40%	38%	0%
Virginia	46%	42%	43%	45%	44%	45%	40%	38%	40%	38%	-2%
Arizona	33%	34%	38%	36%	35%	38%	38%	41%	42%	39%	2%
North Carolina	40%	37%	40%	39%	40%	38%	40%	41%	42%	43%	1%
Iowa	26%	26%	30%	34%	38%	38%	43%	48%	48%	43%	5%
Pennsylvania	38%	37%	37%	37%	38%	40%	41%	42%	43%	43%	1%
Maryland	39%	37%	42%	43%	47%	45%	48%	47%	54%	44%	1%
New Jersey	57%	51%	53%	53%	54%	49%	47%	41%	47%	45%	-2%
Connecticut	57%	54%	51%	50%	51%	51%	49%	48%	51%	46%	-2%
Minnesota	38%	39%	40%	43%	41%	43%	43%	45%	49%	47%	2%
Montana	39%	35%	46%	45%	41%	45%	41%	44%	47%	48%	2%
California	42%	45%	53%	38%	39%	38%	40%	50%	56%	53%	2%
Kansas	25%	27%	24%	30%	34%	39%	43%	47%	58%	54%	8%
Tennessee	48%	45%	46%	44%	53%	47%	47%	47%	53%	58%	2%
Illinois	51%	50%	52%	53%	53%	54%	56%	59%	60%	59%	1%
South Carolina	56%	54%	55%	57%	63%	59%	60%	62%	63%	59%	0%
New York	57%	53%	55%	52%	56%	55%	55%	56%	62%	60%	0%
Oregon	66%	64%	80%	77%	70%	73%	68%	71%	73%	70%	1%
District of Columbia							58%	69%	71%	71%	
South Dakota	59%	66%	77%	73%	67%	71%	76%	74%	75%	72%	2%
Maine	50%	47%	53%	56%	60%	61%	67%	65%	75%	74%	4%
New Hampshire	58%	61%	55%	56%	71%	69%	64%	73%	77%	77%	3%
Idaho	86%	85%	92%	87%	77%	82%	75%	78%	82%	81%	-1%
Washington	81%	81%	91%	92%	84%	84%	83%	86%	86%	86%	1%
Vermont	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	0%

Carbon-free Generation as a percent of Total Generation

Excluding carbon-emitting renewable sources, Michigan's 32.5% of total generation ranks 24th lowest in the country, behind Minnesota and Illinois among its peer states. Michigan's average annual compound growth rate of 3.4% is the 20th highest growth rate among all states.

Figure 57: 2018 Carbon-free Generation as a percent of Total Generation

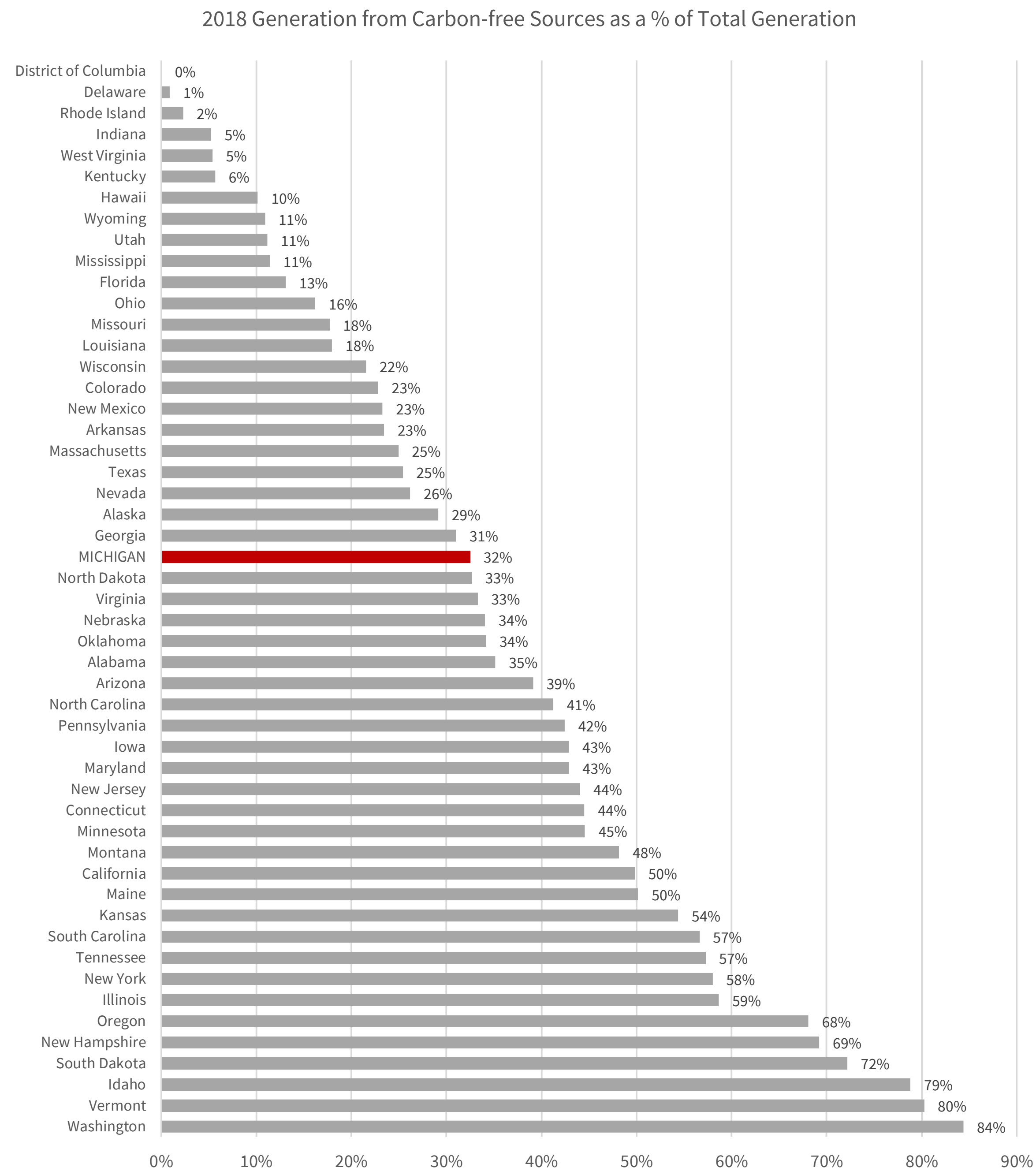


Figure 58: Carbon-free Generation as a percent of Total Generation

Generation from Carbon-free Sources as a % of Total Generation											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
District of Columbia										0%	
Delaware		0%	0%	0%	1%	1%	1%	1%	1%	1%	
Rhode Island	0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	44%
Indiana	2%	3%	3%	3%	4%	3%	5%	5%	6%	5%	12%
West Virginia	3%	3%	3%	4%	4%	3%	4%	4%	5%	5%	5%
Kentucky	4%	3%	3%	3%	4%	3%	4%	4%	6%	6%	4%
Hawaii	5%	5%	6%	7%	9%	9%	10%	11%	11%	10%	8%
Wyoming	7%	9%	12%	11%	10%	11%	9%	11%	12%	11%	5%
Utah	3%	3%	5%	5%	3%	4%	4%	8%	13%	11%	14%
Mississippi	23%	18%	20%	13%	21%	19%	18%	9%	12%	11%	-7%
Florida	13%	11%	10%	8%	12%	12%	12%	12%	13%	13%	0%
Ohio	12%	11%	11%	14%	13%	13%	16%	16%	16%	16%	3%
Missouri	14%	12%	12%	14%	12%	13%	16%	15%	14%	18%	2%
Louisiana	20%	19%	17%	16%	18%	18%	15%	17%	17%	18%	-1%
Wisconsin	25%	26%	24%	27%	23%	22%	21%	22%	21%	22%	-2%
Colorado	10%	10%	14%	15%	16%	17%	18%	22%	23%	23%	9%
New Mexico	5%	6%	6%	8%	7%	9%	9%	14%	18%	23%	18%
Arkansas	34%	31%	28%	27%	24%	28%	31%	28%	26%	23%	-4%
Massachusetts	17%	16%	17%	19%	17%	23%	20%	22%	22%	25%	4%
Texas	16%	17%	16%	17%	17%	18%	19%	22%	24%	25%	5%
Nevada	11%	13%	14%	15%	17%	18%	19%	22%	25%	26%	9%
Alaska	20%	21%	20%	23%	24%	28%	28%	29%	27%	29%	4%
Georgia	27%	27%	28%	30%	30%	28%	29%	29%	30%	31%	1%
MICHIGAN	23%	28%	32%	28%	31%	34%	32%	34%	35%	32%	3%
North Dakota	13%	18%	22%	21%	21%	24%	23%	27%	34%	33%	10%
Virginia	42%	38%	40%	42%	40%	40%	35%	34%	35%	33%	-2%
Nebraska	30%	35%	27%	24%	26%	35%	38%	38%	38%	34%	1%
Oklahoma	8%	9%	10%	12%	18%	19%	22%	29%	35%	34%	15%
Alabama	36%	31%	31%	32%	36%	34%	34%	33%	37%	35%	0%
Arizona	33%	34%	38%	36%	35%	37%	38%	40%	42%	39%	2%
North Carolina	39%	35%	38%	37%	38%	36%	38%	39%	40%	41%	1%
Pennsylvania	37%	36%	36%	36%	37%	38%	40%	41%	42%	42%	1%
Iowa	25%	25%	30%	34%	38%	38%	42%	47%	48%	43%	5%
Maryland	38%	36%	41%	41%	46%	43%	46%	45%	52%	43%	1%
New Jersey	56%	50%	52%	51%	52%	47%	45%	40%	46%	44%	-2%
Connecticut	55%	51%	49%	48%	49%	48%	47%	46%	49%	44%	-2%
Minnesota	35%	36%	37%	39%	38%	40%	40%	42%	46%	45%	3%
Montana	39%	35%	46%	45%	41%	44%	40%	44%	46%	48%	2%
California	39%	42%	50%	35%	35%	34%	36%	47%	53%	50%	3%
Maine	28%	25%	29%	31%	33%	36%	40%	41%	51%	50%	6%
Kansas	25%	27%	24%	30%	34%	39%	43%	47%	57%	54%	8%
South Carolina	54%	52%	53%	54%	60%	57%	58%	60%	60%	57%	0%
Tennessee	47%	44%	45%	43%	51%	46%	46%	46%	51%	57%	2%
New York	55%	51%	53%	50%	54%	53%	54%	54%	60%	58%	1%
Illinois	51%	50%	51%	53%	53%	53%	56%	58%	60%	59%	1%
Oregon	64%	63%	79%	75%	68%	72%	66%	70%	72%	68%	1%
New Hampshire	52%	56%	50%	50%	64%	61%	56%	64%	68%	69%	3%
South Dakota	59%	66%	77%	73%	67%	71%	76%	74%	75%	72%	2%
Idaho	83%	80%	89%	83%	72%	78%	71%	75%	79%	79%	0%
Vermont	94%	93%	94%	95%	93%	93%	76%	75%	79%	80%	-2%
Washington	80%	80%	89%	90%	82%	83%	81%	84%	84%	84%	1%

Renewable and Carbon-free Generation as a percent of Total Sales

As a percent of sales, Michigan's 2018 generation from renewable and carbon-free sources was 38.3%, 26th lowest in the country. This percentage has remained fairly level from 2009-2018.

Figure 59: 2018 Carbon-free and Renewable Generation as a percent of Total Sales

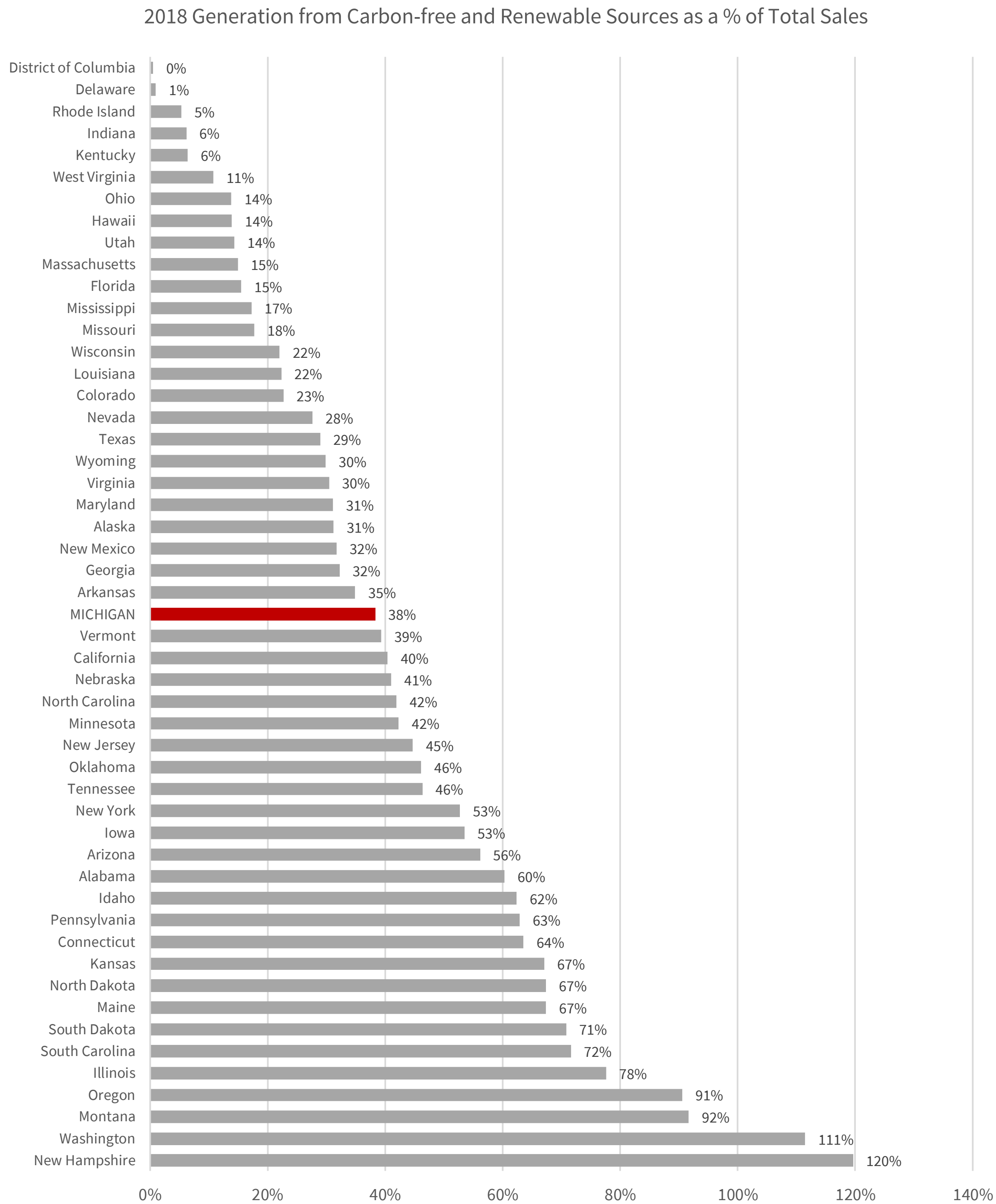


Figure 60: Carbon-free and Renewable Generation as a percent of Total Sales

Generation from Carbon-free and Renewable Sources as a % of Total Sales											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
District of Columbia							0%	0%	0%	0%	
Delaware	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	-1%
Rhode Island	2%	2%	2%	1%	1%	3%	3%	3%	5%	5%	10%
Indiana	2%	3%	4%	4%	4%	4%	5%	6%	6%	6%	11%
Kentucky	4%	3%	4%	3%	4%	5%	5%	5%	7%	6%	4%
West Virginia	8%	7%	8%	9%	10%	8%	9%	10%	11%	11%	3%
Ohio	11%	11%	10%	13%	12%	12%	13%	13%	14%	14%	2%
Hawaii	8%	8%	10%	11%	13%	14%	14%	15%	15%	14%	6%
Utah	5%	5%	8%	6%	5%	6%	6%	11%	16%	14%	12%
Massachusetts	14%	14%	13%	15%	12%	15%	14%	15%	16%	15%	0%
Florida	15%	12%	12%	10%	14%	15%	14%	15%	15%	15%	0%
Mississippi	27%	22%	24%	18%	25%	24%	27%	15%	19%	17%	-4%
Missouri	16%	13%	14%	15%	13%	13%	16%	15%	15%	18%	1%
Wisconsin	25%	26%	24%	28%	24%	22%	23%	23%	22%	22%	-1%
Louisiana	26%	26%	23%	22%	24%	23%	21%	23%	21%	22%	-1%
Colorado	10%	10%	14%	14%	16%	18%	17%	22%	22%	23%	8%
Nevada	12%	13%	14%	15%	18%	18%	20%	24%	26%	28%	8%
Texas	18%	20%	19%	20%	20%	21%	22%	26%	27%	29%	5%
Wyoming	19%	25%	34%	31%	30%	31%	27%	32%	32%	30%	4%
Virginia	30%	27%	26%	30%	30%	31%	30%	31%	32%	30%	0%
Maryland	27%	25%	28%	26%	27%	27%	28%	28%	31%	31%	1%
Alaska	21%	23%	22%	25%	26%	28%	29%	31%	30%	31%	4%
New Mexico	9%	9%	11%	12%	12%	13%	12%	20%	26%	32%	14%
Georgia	29%	28%	28%	30%	31%	29%	31%	31%	32%	32%	1%
Arkansas	49%	42%	39%	41%	35%	40%	41%	40%	37%	35%	-3%
MICHIGAN	26%	33%	35%	31%	35%	38%	37%	39%	41%	38%	4%
Vermont	132%	118%	122%	120%	123%	126%	36%	35%	39%	39%	-11%
California	33%	35%	41%	29%	30%	29%	30%	38%	45%	40%	2%
Nebraska	36%	43%	33%	27%	32%	47%	52%	47%	45%	41%	1%
North Carolina	38%	35%	36%	36%	39%	37%	38%	40%	42%	42%	1%
Minnesota	31%	31%	31%	33%	31%	36%	37%	40%	43%	42%	3%
New Jersey	47%	42%	45%	46%	47%	45%	46%	42%	49%	45%	0%
Oklahoma	12%	12%	12%	16%	23%	22%	28%	37%	43%	46%	15%
Tennessee	40%	36%	37%	36%	43%	38%	36%	37%	43%	46%	1%
New York	54%	50%	52%	49%	51%	51%	52%	51%	54%	53%	0%
Iowa	30%	32%	37%	42%	47%	46%	52%	54%	57%	53%	6%
Arizona	51%	52%	55%	54%	53%	55%	56%	56%	58%	56%	1%
Alabama	67%	54%	57%	59%	64%	59%	62%	57%	64%	60%	-1%
Idaho	50%	45%	66%	57%	48%	54%	51%	53%	60%	62%	2%
Pennsylvania	58%	57%	56%	57%	59%	60%	61%	63%	65%	63%	1%
Connecticut	60%	59%	57%	61%	61%	58%	63%	61%	63%	64%	1%
Kansas	30%	32%	27%	34%	42%	48%	49%	55%	73%	67%	8%
North Dakota	35%	47%	57%	53%	46%	48%	47%	54%	69%	67%	7%
Maine	72%	69%	74%	73%	71%	68%	66%	65%	75%	67%	-1%
South Dakota	44%	58%	79%	71%	55%	63%	61%	70%	67%	71%	5%
South Carolina	74%	68%	70%	70%	76%	70%	71%	76%	75%	72%	0%
Illinois	73%	70%	72%	73%	76%	77%	78%	78%	80%	78%	1%
Oregon	78%	77%	101%	100%	88%	93%	83%	91%	92%	91%	1%
Montana	73%	76%	101%	90%	81%	96%	84%	87%	89%	92%	2%
Washington	94%	93%	112%	116%	103%	106%	101%	110%	108%	111%	2%
New Hampshire	109%	125%	102%	100%	127%	123%	116%	129%	124%	120%	1%

Carbon-free Generation as a percent of Total Sales

Carbon-free generation accounted for 35.9% of total sales in Michigan in 2018, 27th lowest among all states.

Figure 61: 2018 Carbon-free Generation as a percent of Total Sales

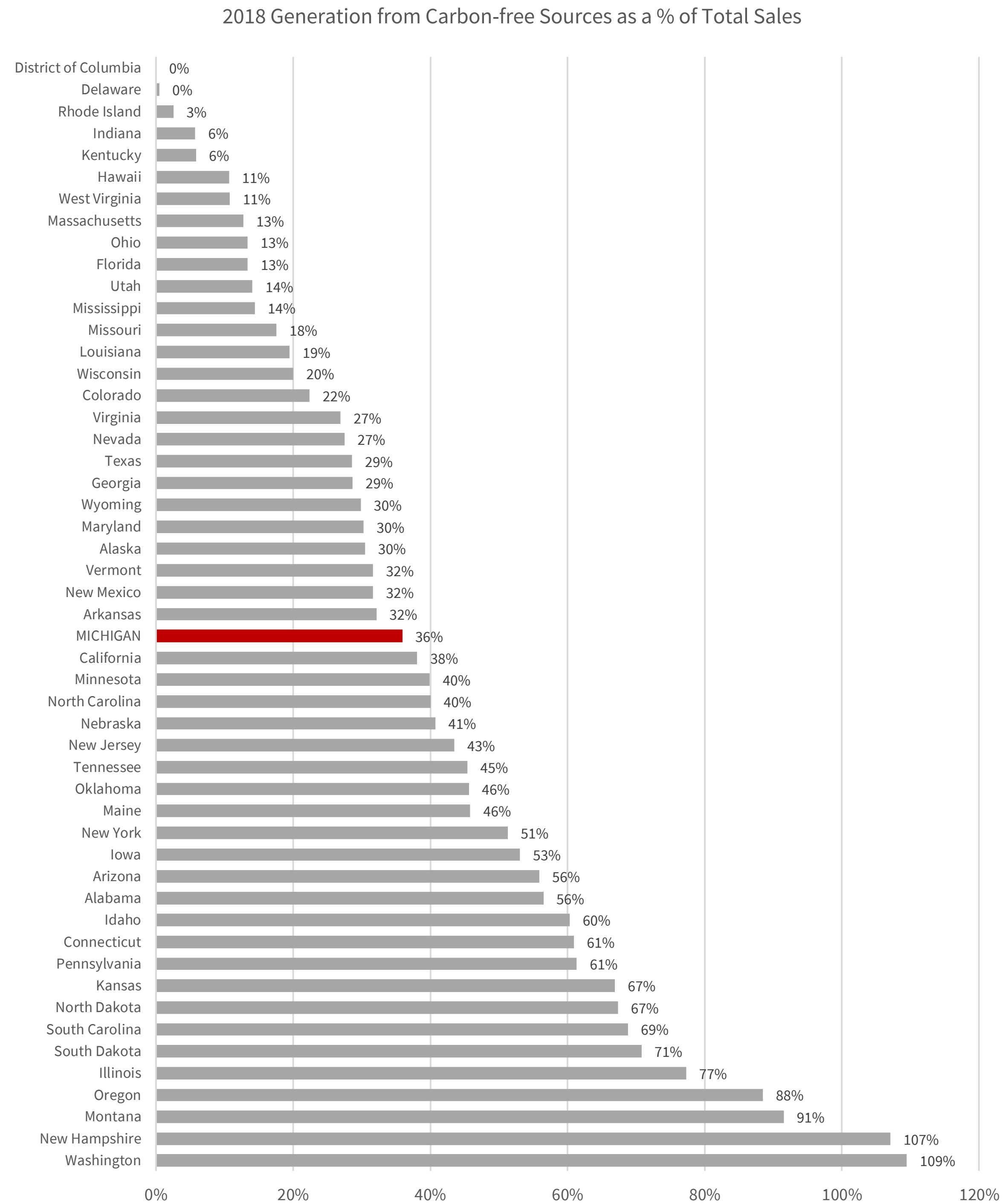


Figure 62: Carbon-free Generation as a percent of Total Sales

Generation from Carbon-free Sources as a % of Total Sales											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
District of Columbia										0%	
Delaware		0%	0%	0%	0%	0%	0%	1%	0%	0%	
Rhode Island	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	45%
Indiana	2%	3%	3%	3%	4%	4%	5%	5%	6%	6%	12%
Kentucky	4%	3%	3%	3%	4%	4%	4%	5%	6%	6%	5%
Hawaii	5%	5%	7%	8%	9%	10%	11%	11%	12%	11%	7%
West Virginia	8%	7%	8%	9%	10%	8%	9%	10%	11%	11%	3%
Massachusetts	12%	12%	11%	12%	10%	13%	12%	13%	14%	13%	0%
Ohio	11%	11%	10%	12%	12%	12%	13%	12%	13%	13%	2%
Florida	13%	10%	10%	8%	12%	13%	12%	13%	13%	13%	0%
Utah	5%	5%	7%	6%	4%	6%	6%	10%	16%	14%	12%
Mississippi	24%	19%	21%	15%	22%	21%	24%	12%	16%	14%	-5%
Missouri	16%	13%	14%	15%	13%	13%	16%	15%	15%	18%	1%
Louisiana	23%	23%	20%	19%	21%	20%	18%	20%	18%	19%	-2%
Wisconsin	23%	24%	22%	25%	22%	19%	20%	21%	20%	20%	-1%
Colorado	10%	10%	14%	14%	16%	18%	17%	22%	22%	22%	8%
Virginia	27%	25%	24%	28%	28%	28%	26%	28%	29%	27%	0%
Nevada	12%	13%	14%	15%	18%	18%	20%	24%	26%	27%	8%
Texas	18%	19%	19%	20%	20%	21%	22%	26%	27%	29%	5%
Georgia	27%	26%	26%	28%	28%	26%	27%	28%	29%	29%	1%
Wyoming	19%	25%	34%	31%	30%	31%	27%	32%	32%	30%	4%
Maryland	26%	24%	27%	25%	26%	27%	27%	28%	30%	30%	1%
Alaska	21%	23%	21%	25%	25%	27%	28%	30%	29%	30%	4%
Vermont	125%	110%	115%	113%	114%	118%	27%	26%	31%	32%	-13%
New Mexico	8%	9%	11%	12%	12%	13%	12%	20%	26%	32%	14%
Arkansas	45%	39%	36%	38%	31%	36%	37%	37%	34%	32%	-3%
MICHIGAN	24%	30%	33%	29%	32%	36%	35%	36%	39%	36%	4%
California	30%	33%	38%	27%	27%	26%	27%	36%	42%	38%	2%
Minnesota	29%	28%	28%	30%	28%	33%	34%	38%	40%	40%	3%
North Carolina	36%	33%	34%	34%	37%	35%	36%	38%	39%	40%	1%
Nebraska	36%	43%	32%	27%	32%	46%	52%	46%	44%	41%	1%
New Jersey	45%	41%	44%	45%	45%	43%	45%	41%	48%	43%	0%
Tennessee	39%	35%	36%	35%	42%	37%	35%	36%	42%	45%	1%
Oklahoma	11%	11%	12%	16%	22%	22%	27%	37%	42%	46%	15%
Maine	40%	37%	41%	40%	39%	39%	39%	41%	51%	46%	1%
New York	52%	48%	51%	48%	50%	50%	50%	49%	53%	51%	0%
Iowa	30%	32%	37%	42%	46%	45%	51%	53%	56%	53%	6%
Arizona	51%	52%	54%	53%	53%	55%	56%	56%	58%	56%	1%
Alabama	63%	51%	54%	56%	61%	56%	58%	53%	60%	56%	-1%
Idaho	48%	42%	63%	54%	45%	51%	48%	51%	58%	60%	2%
Connecticut	58%	56%	55%	59%	59%	55%	60%	58%	60%	61%	1%
Pennsylvania	56%	55%	55%	55%	58%	58%	59%	61%	63%	61%	1%
Kansas	30%	32%	27%	33%	42%	48%	49%	55%	73%	67%	8%
North Dakota	35%	47%	57%	53%	46%	48%	47%	54%	69%	67%	7%
South Carolina	71%	66%	68%	68%	73%	67%	69%	73%	72%	69%	0%
South Dakota	44%	58%	79%	71%	55%	63%	61%	70%	67%	71%	5%
Illinois	72%	70%	72%	73%	75%	76%	78%	78%	80%	77%	1%
Oregon	77%	75%	100%	98%	86%	91%	81%	89%	90%	88%	1%
Montana	72%	75%	101%	90%	81%	95%	83%	87%	89%	91%	2%
New Hampshire	99%	114%	92%	89%	115%	109%	102%	113%	110%	107%	1%
Washington	92%	91%	110%	114%	101%	104%	98%	108%	106%	109%	2%

NATURAL GAS METRICS

Although responsible for significant greenhouse gas emissions and other pollutants, natural gas remains an affordable and accessible fuel for water and space heating in the Midwest. However, consumers are not insulated from price spikes or distribution disruptions, especially during harsh winters in the Midwest. Despite environmental and safety concerns, natural gas is a key component of overall energy affordability especially for residential consumers.

The recent abundance of natural gas from hydraulic fracturing has caused prices to drop, displacing coal-fired power plants as the primary electricity generation source in many Midwestern states. The upper Midwest is home to a dense network of natural gas transmission and distribution pipelines, service electricity generators, commercial and residential consumers, and several industrial uses. Pipeline leaks can cause major environmental degradation and pose a threat to the public.

Natural gas data is collected as part of form EIA-176. This records total supply, disposition, losses, and unaccounted gas. Losses are due to pipeline leaks, accidents, damage, thefts, or blow down. Unaccounted-for gas is the difference between the total supply and the total disposition (accounted for consumption, deliveries, or losses). Sources of unaccounted-for gas could be recording errors or physical losses not included in the previous list. The following section examines Michigan's performance against other states on affordability and usage metrics, as well as on the amount of lost and unaccounted-for gas.

Affordability

Natural Gas Expenditure

While Michigan customers face a relatively low price for natural gas, average household usage is very high, leading to an average household expenditure of $813 in 2018, 19th highest in the country and in line with its peers.

Figure 63: 2018 Average Natural Gas Expenditure: Residential Sector

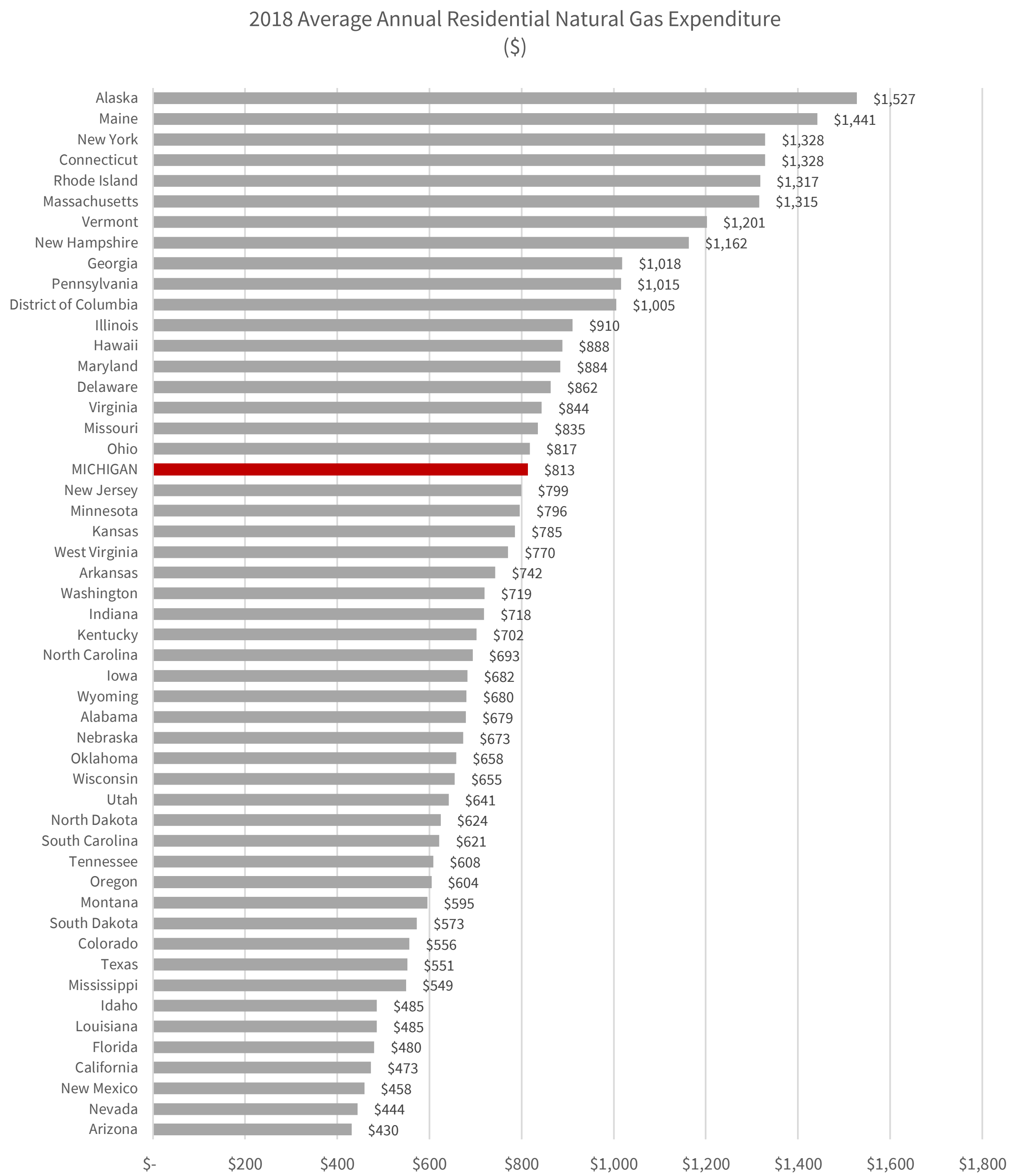


Figure 64: Average Residential Natural Gas Expenditure

Average Annual Residential Natural Gas Expenditure											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Alaska	$1,701	$1,373	$1,460	$1,472	$1,367	$1,278	$1,392	$1,336	$1,609	$1,527	-1%
Maine	$1,016	$825	$891	$1,006	$1,160	$1,473	$1,462	$1,084	$1,189	$1,441	4%
New York	$1,414	$1,265	$1,240	$1,063	$1,185	$1,304	$1,141	$997	$1,159	$1,328	-1%
Connecticut	$1,331	$1,301	$1,250	$1,154	$1,214	$1,384	$1,199	$1,098	$1,229	$1,328	0%
Rhode Island	$1,359	$1,240	$1,145	$993	$1,144	$1,277	$1,208	$993	$1,070	$1,317	0%
Massachusetts	$1,440	$1,313	$1,267	$1,053	$1,074	$1,259	$1,116	$934	$1,068	$1,315	-1%
Vermont	$1,478	$1,306	$1,338	$1,262	$1,317	$1,330	$1,290	$1,125	$1,095	$1,201	-2%
New Hampshire	$1,141	$1,022	$1,048	$885	$1,007	$1,273	$1,237	$936	$1,011	$1,162	0%
Georgia	$1,108	$1,209	$1,024	$911	$984	$1,105	$971	$941	$1,044	$1,018	-1%
Pennsylvania	$1,273	$1,090	$1,025	$883	$1,001	$1,107	$951	$795	$901	$1,015	-2%
District of Columbia	$1,307	$1,277	$1,112	$934	$1,121	$1,257	$1,093	$835	$987	$1,005	-3%
Illinois	$1,028	$1,018	$952	$769	$967	$1,188	$824	$782	$854	$910	-1%
Hawaii	$728	$892	$1,062	$1,011	$1,084	$958	$792	$720	$769	$888	2%
Maryland	$1,063	$973	$874	$793	$885	$1,004	$895	$780	$862	$884	-2%
Delaware	$1,200	$1,018	$1,015	$851	$894	$943	$879	$689	$738	$862	-3%
Virginia	$1,038	$990	$881	$757	$855	$946	$833	$694	$779	$844	-2%
Missouri	$994	$929	$918	$732	$853	$918	$809	$695	$738	$835	-2%
Ohio	$1,140	$974	$953	$766	$860	$992	$824	$694	$754	$817	-3%
MICHIGAN	$1,163	$1,093	$1,056	$871	$955	$1,037	$856	$745	$767	$813	-4%
New Jersey	$1,247	$1,062	$946	$794	$917	$887	$723	$650	$727	$799	-4%
Minnesota	$842	$754	$771	$603	$785	$985	$691	$625	$689	$796	-1%
Kansas	$922	$834	$761	$598	$807	$875	$689	$616	$687	$785	-2%
West Virginia	$1,123	$894	$800	$713	$778	$852	$770	$638	$628	$770	-4%
Arkansas	$799	$760	$701	$563	$666	$722	$695	$548	$602	$742	-1%
Washington	$1,108	$866	$973	$871	$860	$746	$749	$713	$823	$719	-4%
Indiana	$909	$716	$732	$617	$724	$834	$696	$576	$638	$718	-2%
Kentucky	$822	$719	$697	$579	$698	$803	$702	$602	$652	$702	-2%
North Carolina	$849	$835	$685	$603	$709	$755	$619	$593	$634	$693	-2%
Iowa	$787	$744	$724	$592	$728	$852	$588	$544	$608	$682	-1%
Wyoming	$776	$720	$746	$616	$710	$770	$675	$621	$684	$680	-1%
Alabama	$832	$856	$714	$582	$708	$741	$601	$514	$546	$679	-2%
Nebraska	$732	$703	$682	$527	$656	$708	$585	$495	$575	$673	-1%
Oklahoma	$767	$795	$687	$587	$689	$744	$646	$570	$617	$658	-2%
Wisconsin	$865	$768	$756	$621	$731	$928	$629	$582	$626	$655	-3%
Utah	$720	$661	$712	$619	$705	$681	$638	$644	$651	$641	-1%
North Dakota	$798	$689	$707	$548	$670	$803	$608	$506	$581	$624	-2%
South Carolina	$716	$739	$602	$518	$609	$666	$559	$530	$549	$621	-1%
Tennessee	$741	$716	$630	$494	$615	$717	$577	$478	$508	$608	-2%
Oregon	$963	$747	$796	$701	$716	$683	$645	$632	$685	$604	-5%
Montana	$809	$701	$737	$591	$650	$733	$576	$510	$594	$595	-3%
South Dakota	$739	$662	$652	$518	$650	$736	$534	$480	$529	$573	-3%
Colorado	$700	$653	$652	$577	$633	$695	$591	$516	$545	$556	-2%
Texas	$506	$571	$472	$410	$492	$586	$498	$450	$482	$551	1%
Mississippi	$602	$633	$520	$424	$509	$610	$513	$462	$470	$549	-1%
Idaho	$786	$619	$669	$558	$618	$572	$539	$531	$563	$485	-5%
Louisiana	$540	$598	$499	$381	$465	$536	$438	$397	$420	$485	-1%
Florida	$455	$496	$439	$384	$407	$450	$414	$425	$427	$480	1%
California	$431	$466	$479	$409	$444	$424	$417	$447	$489	$473	1%
New Mexico	$551	$606	$549	$503	$562	$571	$494	$450	$471	$458	-2%
Nevada	$672	$631	$560	$480	$494	$497	$531	$477	$422	$444	-4%
Arizona	$542	$527	$506	$476	$471	$470	$490	$441	$419	$430	-2%

Price

Residential Gas Price

As shown in Figure 65 Michigan residential consumers paid $8.19/thousand cubic feet on average, making Michigan residential prices the 43rd highest among states in 2018. Most of Michigan's peer states had similar residential gas prices and rankings. Figure 66 shows Michigan's prices have steadily decreased from 2009-2018.

Figure 65: 2018 Residential Gas Price

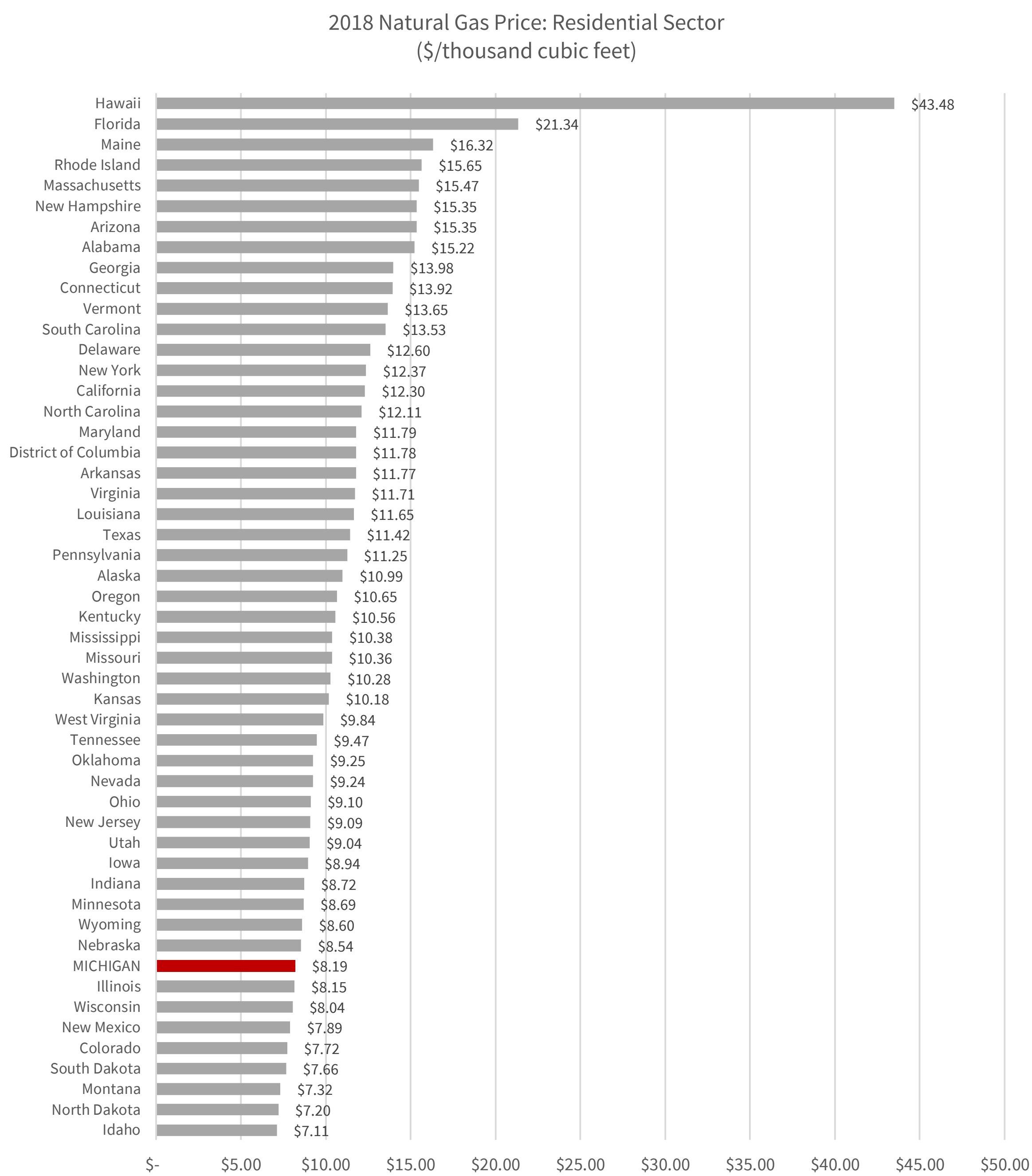


Figure 66: Residential Gas Price

Natural Gas Price: Residential Sector ($/thousand cubic feet)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Hawaii	$36.37	$44.50	$55.28	$52.86	$49.13	$47.51	$40.08	$36.48	$38.88	$43.48	2%
Florida	$20.18	$17.89	$18.16	$18.34	$18.46	$19.02	$19.34	$20.27	$21.15	$21.34	1%
Maine	$16.43	$14.14	$14.20	$15.94	$15.21	$16.90	$16.79	$13.82	$14.61	$16.32	0%
Rhode Island	$17.06	$16.48	$15.33	$14.29	$14.55	$15.14	$14.24	$13.80	$14.02	$15.65	-1%
Massachusetts	$14.85	$14.53	$13.81	$13.22	$13.49	$14.50	$13.02	$12.46	$13.32	$15.47	0%
New Hampshire	$15.33	$14.46	$14.67	$13.74	$13.84	$16.27	$16.18	$14.25	$14.55	$15.35	0%
Arizona	$17.65	$15.87	$15.04	$15.75	$13.92	$17.20	$17.04	$15.28	$15.78	$15.35	-1%
Alabama	$18.12	$15.79	$15.08	$16.20	$15.47	$14.62	$14.13	$14.06	$16.12	$15.22	-2%
Georgia	$16.30	$15.17	$15.72	$16.23	$14.60	$14.45	$14.62	$14.56	$16.93	$13.98	-2%
Connecticut	$14.81	$14.93	$13.83	$14.17	$13.32	$14.13	$12.50	$12.91	$13.95	$13.92	-1%
Vermont	$17.29	$16.14	$16.17	$16.73	$15.87	$14.68	$14.56	$14.15	$14.12	$13.65	-2%
South Carolina	$14.91	$13.01	$12.93	$13.25	$12.61	$12.65	$12.62	$12.62	$14.57	$13.53	-1%
Delaware	$17.79	$15.12	$15.38	$15.24	$13.65	$13.21	$12.62	$11.88	$12.84	$12.60	-3%
New York	$15.05	$14.04	$13.71	$12.97	$12.49	$12.54	$11.20	$10.84	$12.04	$12.37	-2%
California	$9.43	$9.92	$9.93	$9.14	$9.92	$11.51	$11.39	$11.84	$12.49	$12.30	3%
North Carolina	$14.25	$12.50	$12.55	$12.19	$11.83	$11.88	$11.57	$11.31	$13.29	$12.11	-2%
Maryland	$13.73	$12.44	$12.10	$12.17	$11.67	$12.21	$12.03	$11.53	$12.97	$11.79	-2%
District of Columbia	$13.92	$13.53	$13.06	$12.10	$12.45	$13.05	$11.98	$10.90	$12.53	$11.78	-2%
Arkansas	$13.39	$11.53	$11.46	$11.82	$10.46	$10.39	$11.58	$11.17	$12.97	$11.77	-1%
Virginia	$13.83	$12.73	$12.72	$12.42	$11.68	$12.07	$11.64	$10.88	$12.34	$11.71	-2%
Louisiana	$13.15	$11.73	$11.37	$11.54	$10.80	$10.89	$10.77	$11.35	$13.04	$11.65	-1%
Texas	$11.19	$10.82	$10.21	$10.55	$10.50	$11.16	$10.64	$11.73	$13.61	$11.42	0%
Pennsylvania	$14.74	$12.90	$12.46	$11.99	$11.63	$11.77	$11.04	$10.18	$11.40	$11.25	-3%
Alaska	$10.23	$8.89	$8.77	$8.47	$8.85	$9.11	$9.64	$9.81	$10.52	$10.99	1%
Oregon	$14.52	$12.49	$11.76	$11.22	$10.84	$11.72	$12.49	$11.67	$10.59	$10.65	-3%
Kentucky	$11.97	$10.02	$10.44	$10.19	$9.80	$10.62	$10.87	$10.14	$11.62	$10.56	-1%
Mississippi	$11.25	$10.19	$9.47	$9.60	$9.00	$9.51	$9.70	$10.06	$11.83	$10.38	-1%
Missouri	$12.61	$11.66	$12.02	$12.25	$10.88	$10.83	$11.60	$10.94	$11.78	$10.36	-2%
Washington	$13.95	$12.24	$12.30	$11.87	$11.37	$10.59	$11.81	$10.78	$10.62	$10.28	-3%
Kansas	$11.10	$10.61	$9.93	$10.12	$10.19	$10.59	$10.17	$9.85	$10.95	$10.18	-1%
West Virginia	$14.75	$11.39	$10.91	$10.77	$9.98	$10.21	$10.48	$9.26	$9.43	$9.84	-4%
Tennessee	$12.15	$10.46	$10.21	$9.95	$9.44	$10.13	$9.62	$9.21	$10.31	$9.47	-2%
Oklahoma	$11.39	$11.12	$10.32	$11.10	$9.71	$10.10	$10.24	$10.57	$11.40	$9.25	-2%
Nevada	$13.18	$12.25	$10.66	$10.14	$9.42	$11.44	$11.82	$10.23	$8.82	$9.24	-3%
Ohio	$12.68	$11.13	$10.78	$9.91	$9.46	$10.16	$9.51	$9.03	$9.72	$9.10	-3%
New Jersey	$14.54	$12.84	$11.78	$11.09	$10.89	$9.69	$8.32	$8.30	$9.14	$9.09	-5%
Utah	$8.95	$8.22	$8.44	$8.70	$8.55	$9.48	$9.72	$9.12	$9.05	$9.04	0%
Iowa	$9.83	$9.57	$9.54	$9.46	$8.99	$10.02	$8.51	$8.13	$9.30	$8.94	-1%
Indiana	$10.81	$8.63	$9.46	$8.94	$8.43	$9.02	$8.92	$7.92	$8.94	$8.72	-2%
Minnesota	$8.99	$8.76	$8.85	$7.99	$8.19	$9.89	$8.79	$8.01	$8.47	$8.69	0%
Wyoming	$9.39	$8.58	$8.72	$8.42	$8.27	$9.34	$9.33	$8.51	$9.01	$8.60	-1%
Nebraska	$9.34	$8.95	$8.84	$8.68	$8.39	$8.77	$8.86	$8.01	$9.01	$8.54	-1%
MICHIGAN	$11.27	$11.32	$10.47	$9.95	$9.09	$9.33	$8.81	$8.21	$8.38	$8.19	-3%
Illinois	$8.97	$9.39	$8.78	$8.26	$8.20	$9.59	$7.97	$7.88	$8.83	$8.15	-1%
Wisconsin	$10.76	$10.34	$9.77	$9.27	$8.65	$10.52	$8.54	$8.07	$8.40	$8.04	-3%
New Mexico	$9.53	$9.63	$9.14	$8.69	$8.92	$10.13	$8.63	$8.05	$9.22	$7.89	-2%
Colorado	$8.80	$8.13	$8.25	$8.28	$7.85	$8.89	$8.27	$7.35	$8.08	$7.72	-1%
South Dakota	$9.14	$8.77	$8.59	$8.39	$8.23	$9.27	$8.30	$7.60	$8.18	$7.66	-2%
Montana	$9.50	$8.64	$8.80	$8.05	$8.19	$9.11	$8.21	$7.27	$7.62	$7.32	-3%
North Dakota	$8.46	$8.08	$8.10	$7.43	$7.43	$8.86	$8.15	$7.21	$7.64	$7.20	-2%
Idaho	$10.54	$8.95	$8.80	$8.26	$8.12	$8.54	$8.59	$8.14	$7.65	$7.11	-4%

Commercial Gas Price

Figure 67 shows that Michigan's commercial gas price ranked 38th highest in 2018 with a rate of $6.91/thousand cubic feet. Most of its peer states had similar rankings and rates.

Figure 67: 2018 Commercial Gas Price

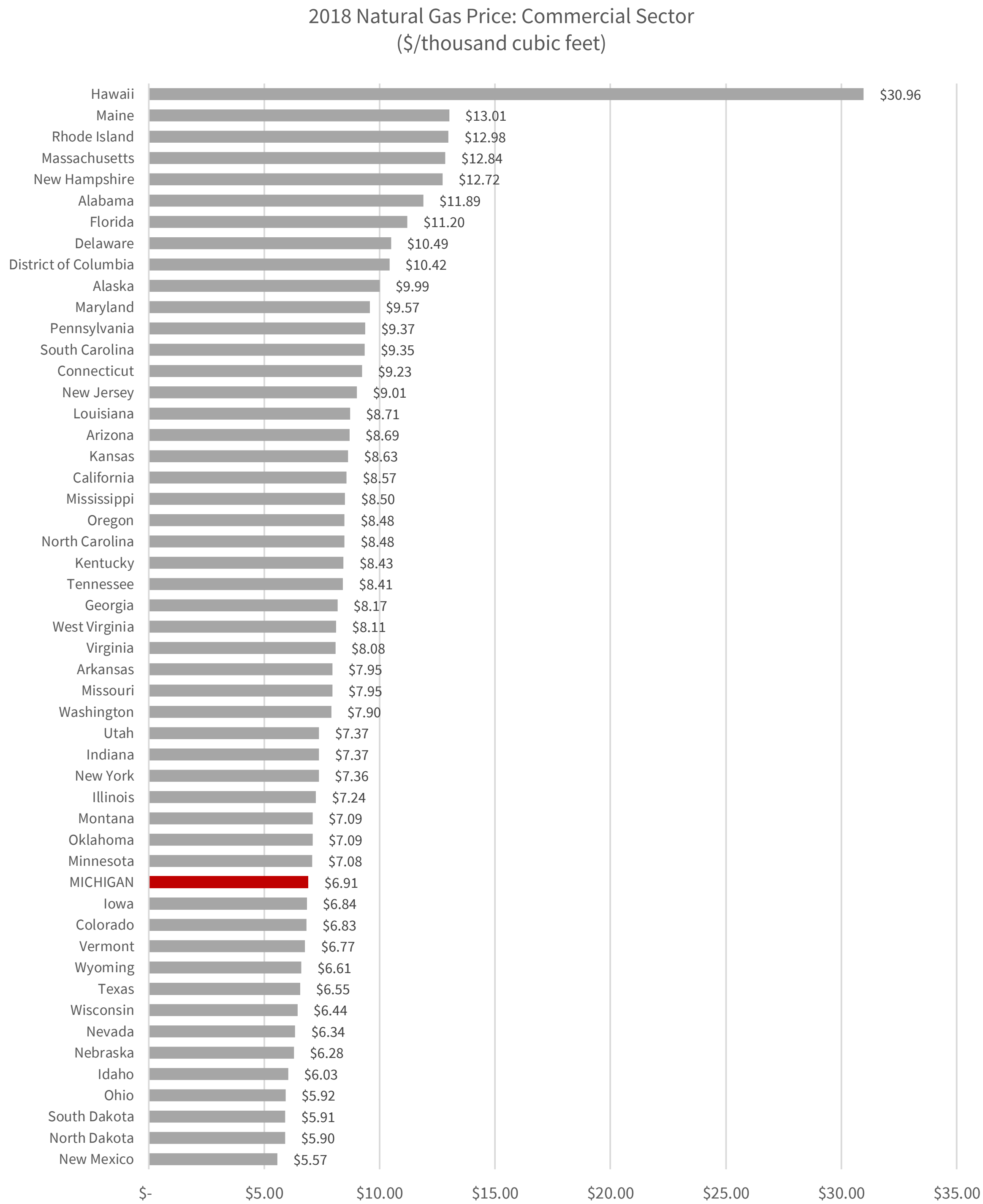


Figure 68: Commercial Gas Price

Natural Gas Price: Commercial Sector ($/thousand cubic feet)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Hawaii	$30.00	$36.55	$45.58	$47.03	$41.92	$40.42	$31.17	$24.78	$27.41	$30.96	0%
Maine	$13.94	$11.71	$11.69	$12.22	$12.79	$15.13	$14.16	$10.63	$11.33	$13.01	-1%
Rhode Island	$15.14	$14.46	$13.33	$12.31	$12.37	$12.89	$11.99	$11.16	$11.30	$12.98	-2%
Massachusetts	$12.85	$12.00	$11.68	$10.68	$11.25	$12.48	$10.81	$9.48	$10.16	$12.84	0%
New Hampshire	$14.37	$12.72	$11.46	$11.95	$12.13	$14.96	$13.63	$11.36	$11.71	$12.72	-1%
Alabama	$14.94	$13.34	$12.36	$12.56	$12.35	$11.98	$11.18	$10.66	$12.04	$11.89	-2%
Florida	$11.09	$10.60	$11.14	$10.41	$10.87	$11.42	$10.88	$10.42	$10.97	$11.20	0%
Delaware	$15.87	$13.26	$13.58	$13.31	$11.78	$11.42	$10.70	$9.58	$10.37	$10.49	-4%
District of Columbia	$12.99	$12.26	$12.24	$11.19	$11.64	$12.18	$11.07	$9.88	$10.87	$10.42	-2%
Alaska	$9.51	$8.78	$8.09	$8.09	$8.34	$8.30	$8.01	$8.34	$9.79	$9.99	0%
Maryland	$10.87	$9.87	$10.29	$10.00	$10.06	$10.52	$9.80	$8.94	$10.27	$9.57	-1%
Pennsylvania	$11.83	$10.47	$10.42	$10.24	$10.11	$10.13	$9.32	$8.15	$9.16	$9.37	-2%
South Carolina	$11.16	$10.34	$9.68	$8.67	$9.10	$9.55	$8.52	$8.42	$9.30	$9.35	-2%
Connecticut	$9.92	$9.55	$8.48	$8.40	$9.20	$10.24	$8.60	$8.79	$9.30	$9.23	-1%
New Jersey	$10.20	$10.11	$9.51	$8.50	$9.55	$10.08	$8.50	$7.93	$9.14	$9.01	-1%
Louisiana	$10.46	$9.88	$9.36	$8.44	$8.59	$9.01	$8.01	$7.92	$8.99	$8.71	-2%
Arizona	$12.15	$10.72	$9.99	$9.35	$8.76	$10.34	$10.53	$8.83	$8.97	$8.69	-3%
Kansas	$10.01	$9.65	$8.89	$8.82	$9.07	$9.61	$8.87	$8.41	$9.30	$8.63	-1%
California	$7.75	$8.30	$8.29	$7.05	$7.81	$9.05	$8.04	$8.42	$8.76	$8.57	1%
Mississippi	$9.48	$8.75	$7.99	$7.37	$7.61	$8.36	$7.87	$7.80	$8.82	$8.50	-1%
Oregon	$11.86	$10.10	$9.60	$8.91	$8.60	$9.44	$10.16	$9.30	$8.74	$8.48	-3%
North Carolina	$11.63	$10.18	$9.64	$8.62	$8.81	$9.12	$8.27	$7.71	$8.92	$8.48	-3%
Kentucky	$10.89	$8.61	$8.79	$8.28	$8.32	$9.06	$8.75	$7.89	$9.06	$8.43	-3%
Tennessee	$10.67	$9.39	$9.04	$8.36	$8.41	$9.30	$8.46	$7.80	$8.74	$8.41	-2%
Georgia	$11.70	$10.95	$10.51	$9.75	$9.38	$9.86	$8.58	$7.92	$8.78	$8.17	-4%
West Virginia	$14.24	$10.27	$9.65	$9.35	$8.61	$8.92	$8.95	$7.75	$7.65	$8.11	-5%
Virginia	$10.31	$9.55	$9.69	$8.77	$8.83	$9.17	$8.13	$7.23	$7.99	$8.08	-2%
Arkansas	$10.72	$8.89	$8.90	$7.99	$7.68	$7.88	$8.43	$7.14	$8.34	$7.95	-3%
Missouri	$10.81	$10.28	$9.99	$9.54	$9.00	$8.96	$9.14	$7.89	$8.44	$7.95	-3%
Washington	$12.26	$10.49	$10.40	$9.82	$9.21	$9.03	$9.78	$8.49	$8.30	$7.90	-4%
Utah	$7.57	$6.83	$7.05	$7.00	$7.13	$7.71	$7.97	$7.43	$7.40	$7.37	0%
Indiana	$9.18	$7.55	$8.04	$7.69	$7.59	$8.19	$7.61	$6.55	$7.52	$7.37	-2%
New York	$10.72	$10.88	$9.32	$7.84	$8.00	$8.31	$6.86	$6.19	$6.87	$7.36	-4%
Illinois	$8.66	$8.76	$8.27	$7.78	$7.57	$8.86	$7.29	$7.14	$7.78	$7.24	-2%
Montana	$9.41	$8.54	$8.66	$7.98	$8.09	$8.77	$8.08	$7.13	$7.42	$7.09	-3%
Oklahoma	$10.59	$9.77	$8.94	$8.95	$8.05	$8.25	$8.12	$7.72	$8.44	$7.09	-4%
Minnesota	$7.96	$7.60	$7.46	$6.36	$6.86	$8.66	$7.31	$6.44	$6.80	$7.08	-1%
MICHIGAN	$9.38	$8.95	$9.14	$8.35	$7.82	$8.28	$7.51	$6.90	$7.02	$6.91	-3%
Iowa	$7.88	$7.81	$7.55	$7.13	$6.97	$8.15	$6.51	$5.99	$6.87	$6.84	-1%
Colorado	$7.56	$7.58	$7.84	$7.58	$7.26	$8.15	$7.47	$6.42	$7.17	$6.83	-1%
Vermont	$12.96	$11.82	$11.90	$12.09	$7.57	$9.13	$7.89	$6.63	$7.04	$6.77	-6%
Wyoming	$8.01	$7.13	$7.29	$6.72	$6.81	$7.69	$7.43	$6.54	$6.92	$6.61	-2%
Texas	$8.15	$7.90	$7.07	$6.63	$7.25	$8.26	$6.92	$6.89	$7.71	$6.55	-2%
Wisconsin	$8.95	$8.53	$8.03	$7.34	$6.94	$8.74	$6.78	$6.29	$6.60	$6.44	-3%
Nevada	$10.92	$9.77	$8.07	$7.43	$6.61	$8.21	$8.66	$6.84	$5.71	$6.34	-5%
Nebraska	$7.44	$7.08	$6.69	$6.19	$6.49	$7.27	$6.40	$5.45	$6.37	$6.28	-2%
Idaho	$9.77	$8.21	$8.09	$7.35	$7.29	$7.70	$7.59	$7.12	$6.62	$6.03	-5%
Ohio	$10.42	$9.25	$8.55	$7.11	$6.21	$7.82	$6.48	$5.74	$6.11	$5.92	-5%
South Dakota	$7.42	$7.13	$6.98	$6.45	$6.59	$7.65	$6.22	$5.64	$6.26	$5.91	-2%
North Dakota	$7.41	$7.03	$7.00	$6.04	$6.32	$7.74	$6.62	$5.45	$6.00	$5.90	-2%
New Mexico	$7.52	$7.47	$6.98	$6.31	$6.77	$7.87	$6.32	$5.68	$6.59	$5.57	-3%

Industrial Gas Price

Figure 69 shows that in 2018, industrial consumers paid $5.98/thousand cubic feet, the 21st highest rate in the country.

Figure 69: 2018 Industrial Gas Price

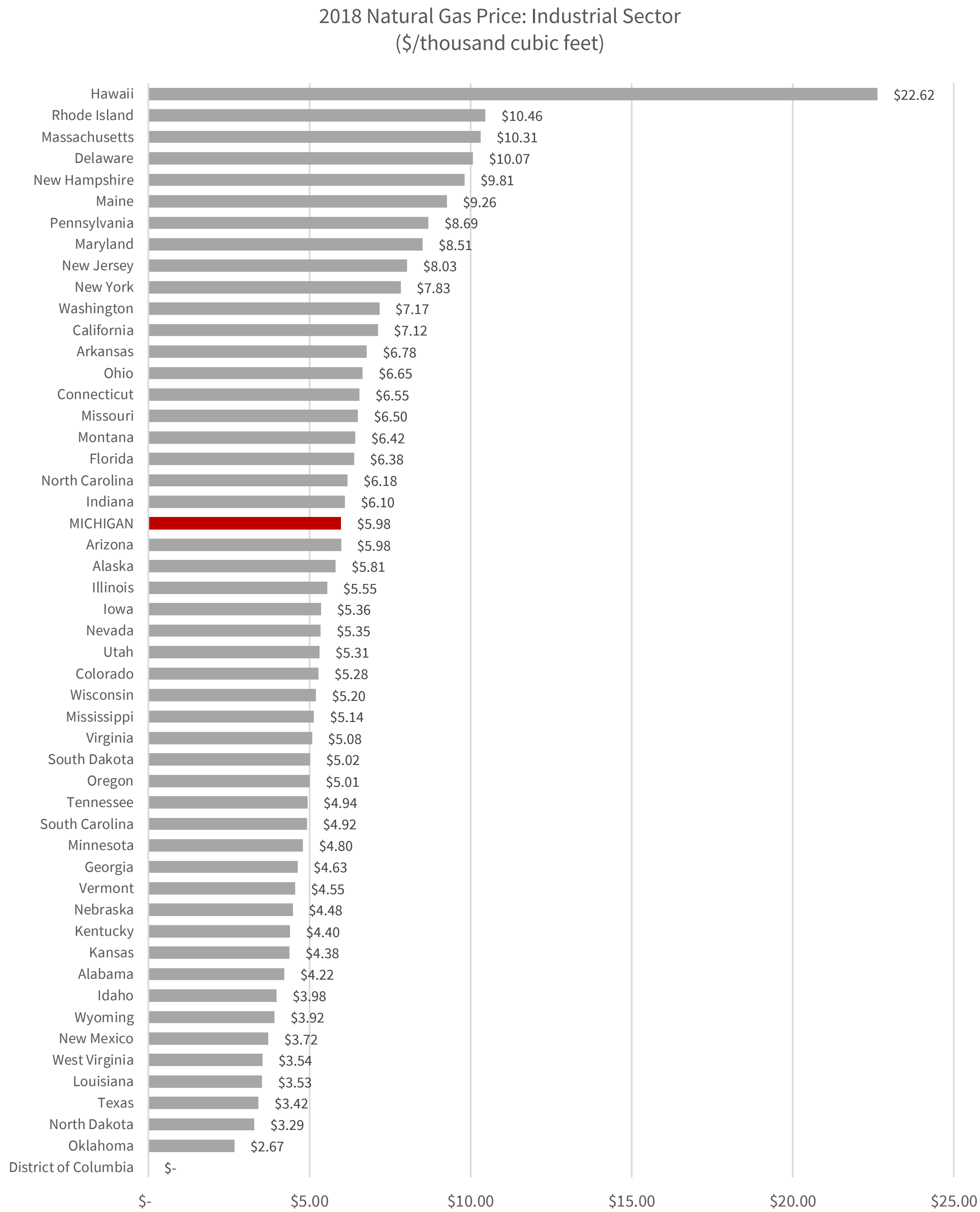


Figure 70: Industrial Gas Price

Natural Gas Price: Industrial Sector ($/thousand cubic feet)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Hawaii	$19.05	$24.10	$29.80	$30.89	$27.56	$26.75	$19.03	$17.74	$19.62	$22.62	2%
Rhode Island	$12.58	$12.13	$10.98	$9.78	$9.04	$10.27	$9.26	$8.70	$8.48	$10.46	-2%
Massachusetts	$12.07	$10.41	$10.14	$9.82	$10.15	$11.53	$9.22	$7.40	$8.02	$10.31	-2%
Delaware	$13.99	$10.18	$11.69	$11.61	$11.24	$10.95	$10.11	$9.02	$9.91	$10.07	-3%
New Hampshire	$12.86	$11.59	$11.57	$10.48	$10.68	$9.46	$10.33	$8.59	$9.09	$9.81	-3%
Maine	$9.12	$11.23	$10.89	$10.35	$10.32	$11.93	$8.95	$7.68	$8.15	$9.26	0%
Pennsylvania	$9.19	$8.23	$9.86	$9.58	$9.13	$9.95	$8.59	$7.40	$8.38	$8.69	-1%
Maryland	$10.70	$9.05	$8.61	$8.01	$8.47	$9.94	$9.70	$8.80	$9.84	$8.51	-2%
New Jersey	$8.96	$9.63	$9.23	$7.87	$8.19	$10.45	$8.09	$6.59	$7.92	$8.03	-1%
New York	$9.52	$8.55	$8.18	$6.92	$7.44	$8.13	$6.62	$5.92	$7.21	$7.83	-2%
Washington	$11.68	$9.37	$9.47	$8.77	$8.37	$8.55	$8.94	$7.47	$7.39	$7.17	-5%
California	$6.56	$7.02	$7.04	$5.77	$6.57	$7.65	$6.41	$6.79	$7.05	$7.12	1%
Arkansas	$8.44	$7.28	$7.44	$6.38	$6.74	$6.99	$6.91	$5.78	$6.65	$6.78	-2%
Ohio	$8.71	$7.40	$6.77	$5.48	$6.03	$7.06	$5.35	$4.81	$6.71	$6.65	-3%
Connecticut	$8.44	$9.60	$9.16	$8.83	$6.85	$8.07	$6.35	$6.07	$6.48	$6.55	-3%
Missouri	$9.55	$8.70	$8.54	$7.85	$8.19	$8.00	$7.58	$6.29	$6.64	$6.50	-4%
Montana	$9.06	$8.07	$8.13	$7.54	$7.33	$7.99	$6.50	$6.06	$6.60	$6.42	-3%
Florida	$9.41	$8.33	$8.07	$6.96	$6.77	$6.89	$6.43	$5.77	$6.17	$6.38	-4%
North Carolina	$8.66	$8.24	$7.70	$6.37	$6.87	$7.55	$6.34	$5.43	$6.24	$6.18	-3%
Indiana	$6.91	$5.65	$6.53	$6.19	$6.54	$7.32	$6.36	$4.99	$5.99	$6.10	-1%
MICHIGAN	$9.63	$9.25	$8.27	$7.38	$6.97	$7.84	$6.60	$5.75	$5.97	$5.98	-5%
Arizona	$8.19	$7.54	$6.86	$5.78	$6.29	$7.52	$6.78	$5.79	$6.47	$5.98	-3%
Alaska	$4.02	$4.23	$3.84	$5.11	$8.16	$7.97	$6.86	$5.06	$4.63	$5.81	4%
Illinois	$7.31	$7.13	$6.84	$5.63	$6.00	$7.75	$5.47	$5.03	$5.76	$5.55	-3%
Iowa	$6.23	$6.10	$5.78	$4.70	$5.43	$7.59	$5.30	$4.70	$5.21	$5.36	-1%
Nevada	$11.22	$10.53	$8.99	$7.34	$6.66	$7.83	$8.07	$5.90	$5.06	$5.35	-7%
Utah	$5.62	$5.57	$5.50	$4.69	$5.22	$5.87	$5.93	$5.52	$5.51	$5.31	-1%
Colorado	$6.57	$5.84	$6.42	$5.79	$5.90	$6.84	$5.74	$4.89	$5.58	$5.28	-2%
Wisconsin	$7.82	$7.56	$7.05	$5.81	$6.02	$8.08	$5.65	$5.05	$5.34	$5.20	-4%
Mississippi	$6.65	$6.19	$5.83	$4.85	$5.82	$6.15	$4.72	$4.34	$5.07	$5.14	-3%
Virginia	$7.14	$6.68	$6.44	$5.29	$6.02	$6.43	$5.02	$4.42	$5.04	$5.08	-3%
South Dakota	$6.07	$5.92	$6.25	$5.37	$5.67	$6.88	$5.34	$4.78	$5.11	$5.02	-2%
Oregon	$9.70	$7.05	$6.84	$5.87	$5.79	$6.20	$7.10	$5.73	$5.31	$5.01	-6%
Tennessee	$7.09	$6.64	$6.15	$4.98	$5.62	$6.31	$5.06	$4.44	$5.04	$4.94	-4%
South Carolina	$6.06	$6.12	$5.60	$4.30	$5.27	$6.14	$4.64	$4.20	$4.86	$4.92	-2%
Minnesota	$5.66	$5.58	$5.55	$4.28	$4.94	$6.57	$4.87	$4.19	$4.48	$4.80	-2%
Georgia	$6.21	$6.25	$5.90	$4.61	$5.38	$6.07	$4.42	$4.13	$4.68	$4.63	-3%
Vermont	$7.93	$6.57	$6.09	$4.89	$8.59	$6.63	$5.50	$5.20	$4.92	$4.55	-5%
Nebraska	$6.02	$5.85	$5.61	$4.34	$4.72	$5.69	$4.56	$4.04	$4.54	$4.48	-3%
Kentucky	$6.04	$5.57	$5.16	$3.96	$4.84	$5.78	$4.37	$3.84	$4.46	$4.40	-3%
Kansas	$4.59	$5.49	$5.28	$3.87	$4.86	$5.68	$4.24	$3.69	$4.16	$4.38	0%
Alabama	$6.48	$6.64	$5.57	$4.35	$4.98	$5.49	$4.09	$3.79	$4.23	$4.22	-4%
Idaho	$8.53	$6.39	$6.36	$5.73	$5.47	$5.96	$5.72	$5.19	$4.44	$3.98	-7%
Wyoming	$5.79	$4.91	$5.57	$4.87	$4.62	$5.89	$5.07	$3.96	$4.28	$3.92	-4%
New Mexico	$5.41	$6.17	$6.22	$4.96	$5.58	$6.18	$4.62	$4.18	$5.06	$3.72	-4%
West Virginia	$5.55	$5.40	$4.89	$3.60	$4.30	$5.00	$3.12	$2.43	$3.21	$3.54	-4%
Louisiana	$4.31	$4.68	$4.25	$2.96	$3.86	$5.05	$3.33	$3.11	$3.64	$3.53	-2%
Texas	$4.05	$4.61	$4.21	$3.02	$3.92	$4.71	$2.89	$2.65	$3.28	$3.42	-2%
North Dakota	$5.21	$5.22	$5.10	$4.48	$4.14	$5.61	$3.13	$2.62	$3.15	$3.29	-4%
Oklahoma	$12.53	$8.23	$7.37	$7.65	$7.16	$8.30	$7.51	$2.94	$3.30	$2.67	-14%
District of Columbia	$-	$-	$-	$-	$-	$-	$-	$-	$-	$-	

Volume

Residential Gas Volume

Figure 71 shows that Michigan residential customers use the fourth most natural gas out of customers of all states. All of Michigan's peer states rank in the top 11 with only Illinois' residential gas usage surpassing Michigan's.

Figure 73 shows that the average residential consumer used 99,238 cubic feet of natural gas in 2018. Michigan ranked 4th highest in per capita residential gas usage with only Illinois exceeding Michigan among its peers.

Figure 71: 2018 Residential Gas Volume

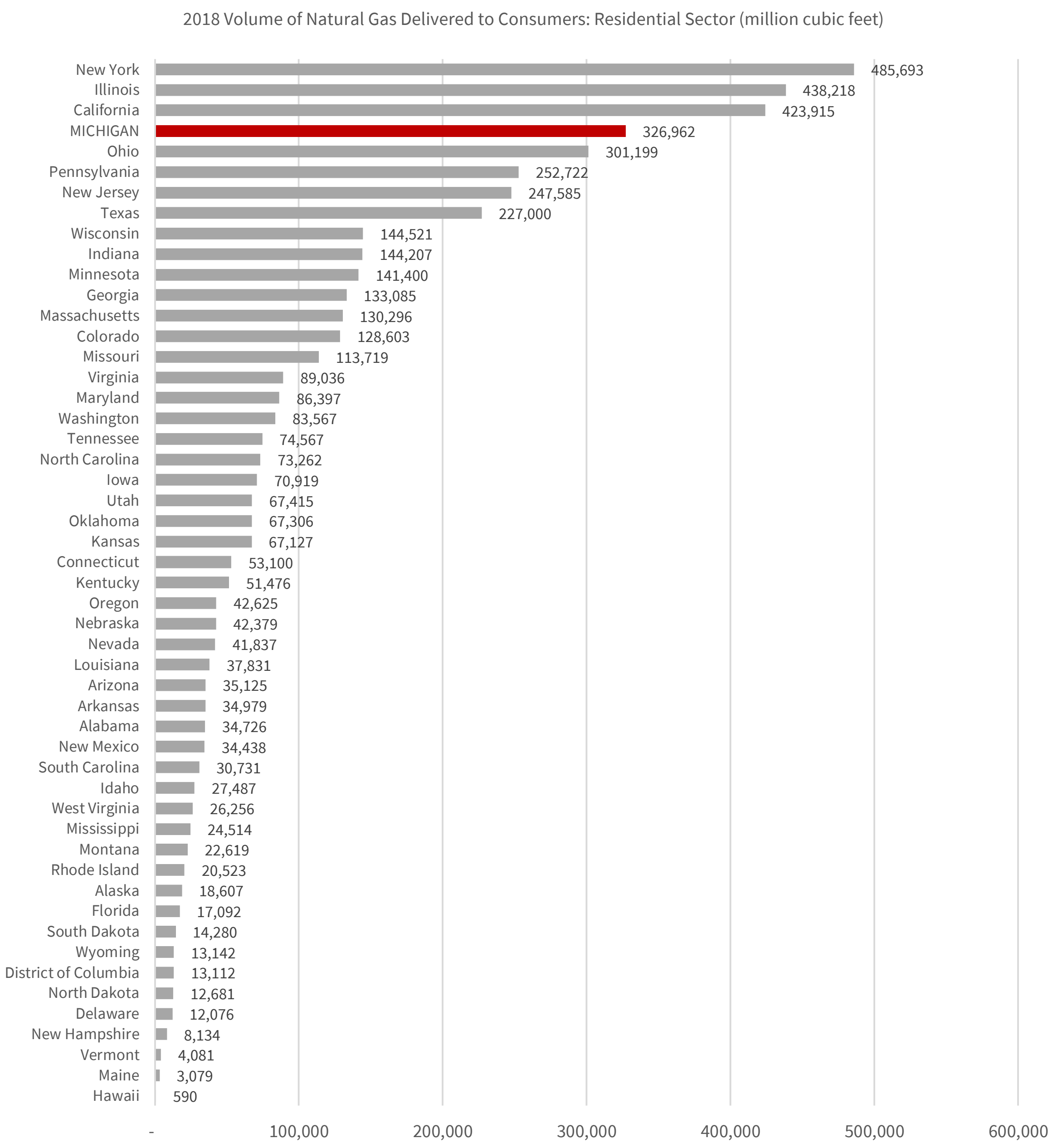


Figure 72: Residential Gas Volume

Volume of Natural Gas Delivered to Consumers: Residential Sector (thousand cubic feet)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
New York	404,868	390,491	393,825	357,709	416,357	458,313	452,166	412,467	432,564	485,693	2%
Illinois	440,065	416,570	418,143	360,891	452,602	479,465	400,876	386,590	377,511	438,218	0%
California	480,721	494,890	512,565	477,931	481,773	397,489	401,172	411,828	431,005	423,915	-1%
MICHIGAN	327,113	304,330	318,004	276,778	334,211	354,713	312,098	294,152	299,158	326,962	0%
Ohio	292,429	283,703	286,132	250,871	297,361	320,568	285,306	255,826	258,699	301,199	0%
Pennsylvania	227,714	223,642	219,446	197,313	231,861	254,816	235,669	215,512	218,734	252,722	1%
New Jersey	226,016	219,141	213,630	191,371	226,195	247,742	237,104	215,510	221,608	247,585	1%
Texas	192,153	226,445	199,958	169,980	207,148	234,520	211,379	175,332	164,147	227,000	2%
Wisconsin	133,176	123,618	129,445	112,554	142,985	150,409	126,854	125,449	131,018	144,521	1%
Indiana	139,743	138,415	132,094	115,522	144,496	156,639	133,045	125,038	123,847	144,207	0%
Minnesota	133,319	122,993	125,160	109,103	139,897	146,647	117,588	117,598	123,898	141,400	1%
Georgia	118,589	138,671	113,335	97,664	121,629	134,482	118,028	115,922	111,248	133,085	1%
Massachusetts	132,883	125,602	129,217	115,310	116,867	126,902	126,662	112,082	121,181	130,296	0%
Colorado	128,993	131,224	130,116	115,695	134,936	132,106	122,364	121,963	118,585	128,603	0%
Missouri	106,301	107,389	102,545	83,106	106,446	115,512	95,503	87,264	86,865	113,719	1%
Virginia	84,445	88,157	79,301	70,438	85,702	92,817	85,464	77,170	76,904	89,036	1%
Maryland	82,699	83,830	77,838	70,346	83,341	90,542	82,858	76,047	75,789	86,397	0%
Washington	84,143	75,554	85,393	79,892	83,365	78,750	71,907	76,321	91,028	83,567	0%
Tennessee	66,111	74,316	67,190	53,810	71,241	78,395	67,312	58,924	56,661	74,567	1%
North Carolina	65,642	74,520	61,644	56,511	69,654	75,178	64,523	64,547	59,933	73,262	1%
Iowa	70,111	68,376	67,097	55,855	72,519	76,574	62,735	61,247	60,362	70,919	0%
Utah	65,184	66,087	70,076	59,801	70,491	62,458	58,562	63,929	66,700	67,415	0%
Oklahoma	62,293	65,429	61,387	49,052	66,108	69,050	59,399	50,573	51,069	67,306	1%
Kansas	71,068	67,117	65,491	50,489	68,036	71,115	58,384	54,060	54,445	67,127	-1%
Connecticut	43,995	42,729	44,719	41,050	46,802	51,193	50,975	46,045	48,431	53,100	2%
Kentucky	51,821	54,391	50,696	43,065	54,208	57,590	49,426	45,502	43,253	51,476	0%
Oregon	44,819	40,821	46,604	43,333	46,254	41,185	37,070	39,391	47,841	42,625	-1%
Nebraska	40,143	40,132	39,717	31,286	41,229	42,147	34,663	33,050	34,069	42,379	1%
Nevada	38,742	39,379	40,595	37,071	41,664	35,135	37,029	39,075	40,911	41,837	1%
Louisiana	36,512	45,516	39,412	31,834	38,820	44,518	36,858	31,383	29,074	37,831	0%
Arizona	34,732	37,812	38,592	34,974	39,692	32,397	34,516	35,120	32,821	35,125	0%
Arkansas	33,252	36,240	33,737	26,191	34,989	38,127	33,049	27,130	25,704	34,979	1%
Alabama	36,061	42,215	36,582	27,580	35,059	39,006	32,750	28,407	26,338	34,726	0%
New Mexico	32,405	35,253	34,299	32,515	36,024	32,374	33,130	32,577	29,993	34,438	1%
South Carolina	27,160	32,430	26,851	22,834	28,642	31,904	28,414	27,562	24,558	30,731	1%
Idaho	25,531	23,975	26,666	23,924	27,370	24,616	23,482	24,889	28,799	27,487	1%
West Virginia	26,172	27,021	25,073	22,538	26,514	28,257	24,807	23,210	22,385	26,256	0%
Mississippi	23,433	27,152	24,303	19,572	25,185	28,261	23,248	20,185	18,446	24,514	0%
Montana	21,765	20,875	21,710	19,069	20,813	21,379	18,912	19,100	21,481	22,619	0%
Rhode Island	17,914	16,942	16,864	15,883	18,221	19,724	20,042	17,200	18,421	20,523	1%
Alaska	19,978	18,714	20,262	21,380	19,215	17,734	18,574	17,787	20,247	18,607	-1%
Florida	15,214	18,744	16,400	14,366	15,321	16,652	15,407	15,352	14,934	17,092	1%
South Dakota	13,595	12,815	12,961	10,742	13,920	14,213	11,751	11,663	12,146	14,280	0%
Wyoming	12,656	12,915	13,283	11,502	13,640	13,269	11,576	11,999	12,553	13,142	0%
District of Columbia	13,466	13,608	12,386	11,260	13,214	14,242	13,494	11,379	11,904	13,112	0%
North Dakota	11,518	10,536	10,937	9,594	12,085	12,505	10,552	10,059	11,015	12,681	1%
Delaware	10,049	10,126	10,030	8,564	10,197	11,316	11,260	9,660	9,896	12,076	2%
New Hampshire	7,213	6,738	6,955	6,422	7,185	7,755	7,842	6,861	7,331	8,134	1%
Vermont	3,183	3,078	3,214	3,012	3,415	3,826	3,833	3,518	3,509	4,081	3%
Maine	1,286	1,234	1,409	1,487	1,889	2,357	2,700	2,566	2,748	3,079	9%
Hawaii	510	509	486	481	582	583	572	571	572	590	1%

Figure 73: 2018 Residential Gas Volume per Customer

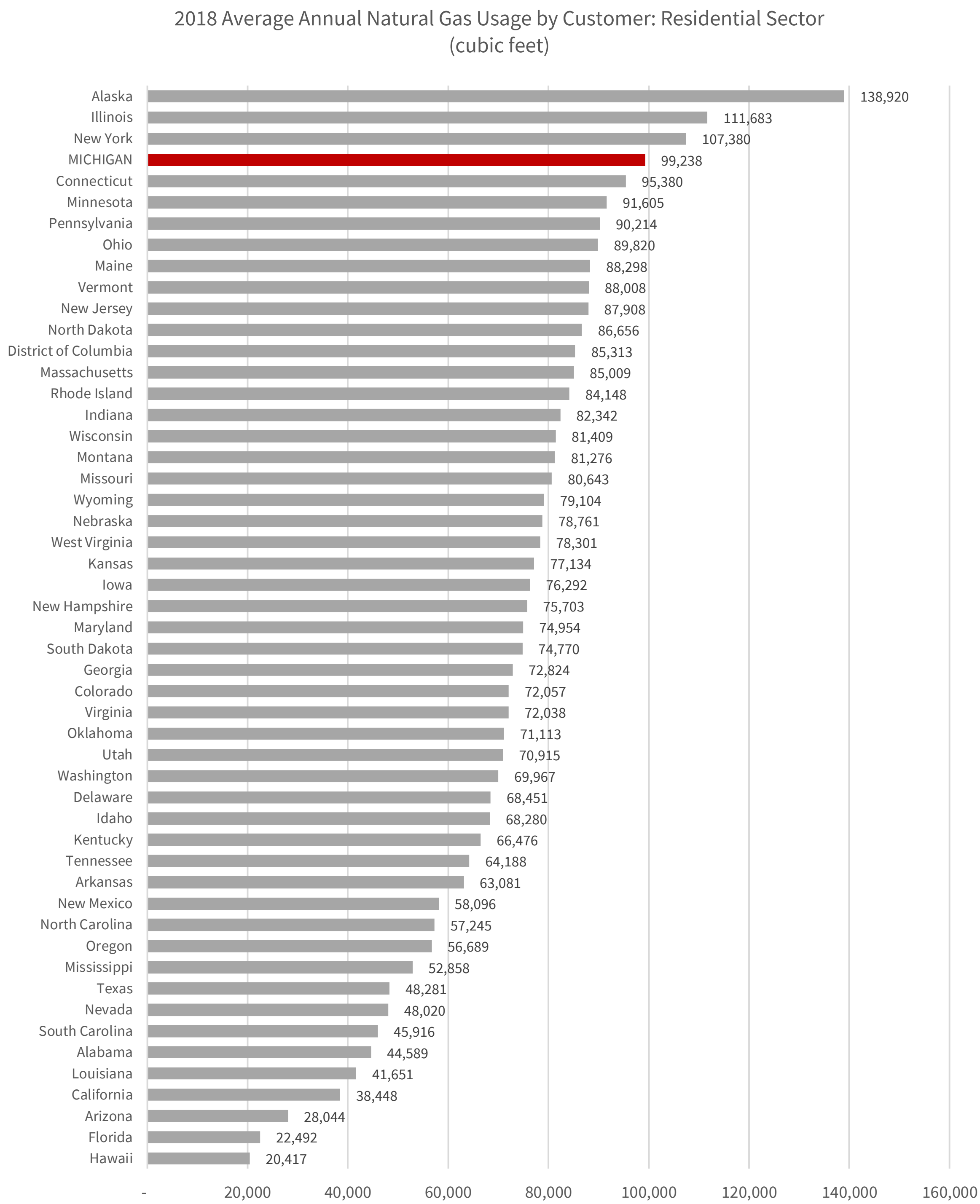


Figure 74: Residential Gas Volume per Customer

Average Annual Natural Gas Usage by Customer: Residential Sector (cubic feet)											
State	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Alaska	166,316	154,449	166,440	173,842	154,447	140,280	144,429	136,146	152,967	138,920	-2%
Illinois	114,617	108,419	108,441	93,042	117,923	123,871	103,416	99,209	96,709	111,683	0%
New York	93,968	90,079	90,458	81,965	94,897	104,019	101,856	91,986	96,290	107,380	1%
MICHIGAN	103,222	96,537	100,829	87,559	105,086	111,098	97,108	90,774	91,498	99,238	0%
Connecticut	89,905	87,169	90,348	81,426	91,145	97,948	95,929	85,025	88,116	95,380	1%
Minnesota	93,643	86,028	87,155	75,461	95,877	99,580	78,560	78,071	81,298	91,605	0%
Pennsylvania	86,390	84,514	82,270	73,664	86,091	94,035	86,136	78,138	79,039	90,214	0%
Ohio	89,890	87,546	88,417	77,327	90,906	97,616	86,613	76,903	77,543	89,820	0%
Maine	61,819	58,347	62,724	63,118	76,259	87,161	87,050	78,458	81,415	88,298	4%
Vermont	85,479	80,905	82,762	75,447	82,988	90,607	88,592	79,514	77,514	88,008	0%
New Jersey	85,764	82,717	80,336	71,639	84,198	91,577	86,904	78,269	79,590	87,908	0%
North Dakota	94,361	85,257	87,224	73,778	90,202	90,637	74,593	70,188	76,028	86,656	-1%
District of Columbia	93,879	94,402	85,110	77,153	90,071	96,312	91,237	76,601	78,768	85,313	-1%
Massachusetts	96,970	90,388	91,753	79,637	79,633	86,839	85,694	74,993	80,206	85,009	-1%
Rhode Island	79,670	75,230	74,674	69,516	78,619	84,369	84,809	71,954	76,295	84,148	1%
Indiana	84,047	82,932	77,377	69,046	85,915	92,507	78,067	72,678	71,349	82,342	0%
Wisconsin	80,390	74,308	77,427	66,957	84,462	88,170	73,682	72,144	74,535	81,409	0%
Montana	85,197	81,123	83,806	73,356	79,404	80,418	70,104	70,096	78,012	81,276	0%
Missouri	78,812	79,633	76,360	59,792	78,399	84,731	69,750	63,492	62,631	80,643	0%
Wyoming	82,684	83,945	85,596	73,159	85,849	82,468	72,382	72,965	75,916	79,104	0%
Nebraska	78,321	78,571	77,198	60,709	78,174	80,678	66,005	61,747	63,818	78,761	0%
West Virginia	76,118	78,520	73,299	66,238	77,960	83,440	73,471	68,848	66,633	78,301	0%
Kansas	83,076	78,605	76,622	59,065	79,243	82,649	67,754	62,506	62,746	77,134	-1%
Iowa	80,056	77,726	75,924	62,609	80,990	85,043	69,086	66,905	65,366	76,292	0%
New Hampshire	74,421	70,663	71,406	64,388	72,782	78,221	76,462	65,668	69,466	75,703	0%
Maryland	77,447	78,232	72,262	65,197	75,815	82,215	74,423	67,653	66,456	74,954	0%
South Dakota	80,876	75,456	75,853	61,789	78,999	79,382	64,364	63,099	64,679	74,770	-1%
Georgia	67,962	79,669	65,135	56,143	67,369	76,437	66,397	64,639	61,642	72,824	1%
Colorado	79,506	80,280	79,063	69,704	80,688	78,142	71,468	70,257	67,400	72,057	-1%
Virginia	75,081	77,802	69,255	60,952	73,239	78,400	71,557	63,804	63,166	72,038	0%
Oklahoma	67,363	71,517	66,563	52,895	70,933	73,674	63,103	53,887	54,154	71,113	1%
Utah	80,431	80,445	84,407	71,133	82,504	71,869	65,658	70,573	71,982	70,915	-1%
Washington	79,438	70,745	79,121	73,379	75,627	70,426	63,431	66,183	77,537	69,967	-1%
Delaware	67,444	67,298	65,982	55,859	65,524	71,393	69,676	57,999	57,512	68,451	0%
Idaho	74,591	69,172	75,999	67,590	76,051	67,002	62,694	65,196	73,640	68,280	-1%
Kentucky	68,659	71,744	66,742	56,829	71,178	75,584	64,613	59,362	56,072	66,476	0%
Tennessee	61,012	68,470	61,699	49,607	65,113	70,823	59,946	51,862	49,225	64,188	1%
Arkansas	59,660	65,894	61,140	47,624	63,643	69,443	59,989	49,096	46,414	63,081	1%
New Mexico	57,817	62,969	60,107	57,886	62,954	56,345	57,242	55,888	51,122	58,096	0%
North Carolina	59,567	66,802	54,602	49,443	59,974	63,540	53,463	52,419	47,735	57,245	0%
Oregon	66,341	59,790	67,671	62,484	66,057	58,253	51,629	54,116	64,648	56,689	-2%
Mississippi	53,535	62,156	54,925	44,196	56,520	64,193	52,903	45,898	39,725	52,858	0%
Texas	45,227	52,803	46,221	38,896	46,823	52,474	46,810	38,340	35,426	48,281	1%
Nevada	50,949	51,514	52,524	47,359	52,464	43,431	44,937	46,581	47,876	48,020	-1%
South Carolina	48,006	56,815	46,568	39,124	48,278	52,677	44,317	42,015	37,675	45,916	0%
Alabama	45,937	54,193	47,331	35,939	45,771	50,664	42,545	36,575	33,856	44,589	0%
Louisiana	41,045	50,947	43,913	33,034	43,055	49,263	40,659	34,989	32,183	41,651	0%
California	45,735	46,942	48,241	44,742	44,796	36,867	36,571	37,726	39,165	38,448	-2%
Arizona	30,735	33,214	33,667	30,210	33,867	27,298	28,745	28,889	26,578	28,044	-1%
Florida	22,570	27,747	24,147	20,911	22,069	23,669	21,414	20,980	20,188	22,492	0%
Hawaii	20,028	20,039	19,219	19,117	22,070	20,167	19,756	19,750	19,791	20,417	0%

Commercial Gas Volume

Figure 75 shows Michigan ranked 5th highest among states in commercial sector natural gas usage in 2018.

Figure 75: 2018 Commercial Gas Volume

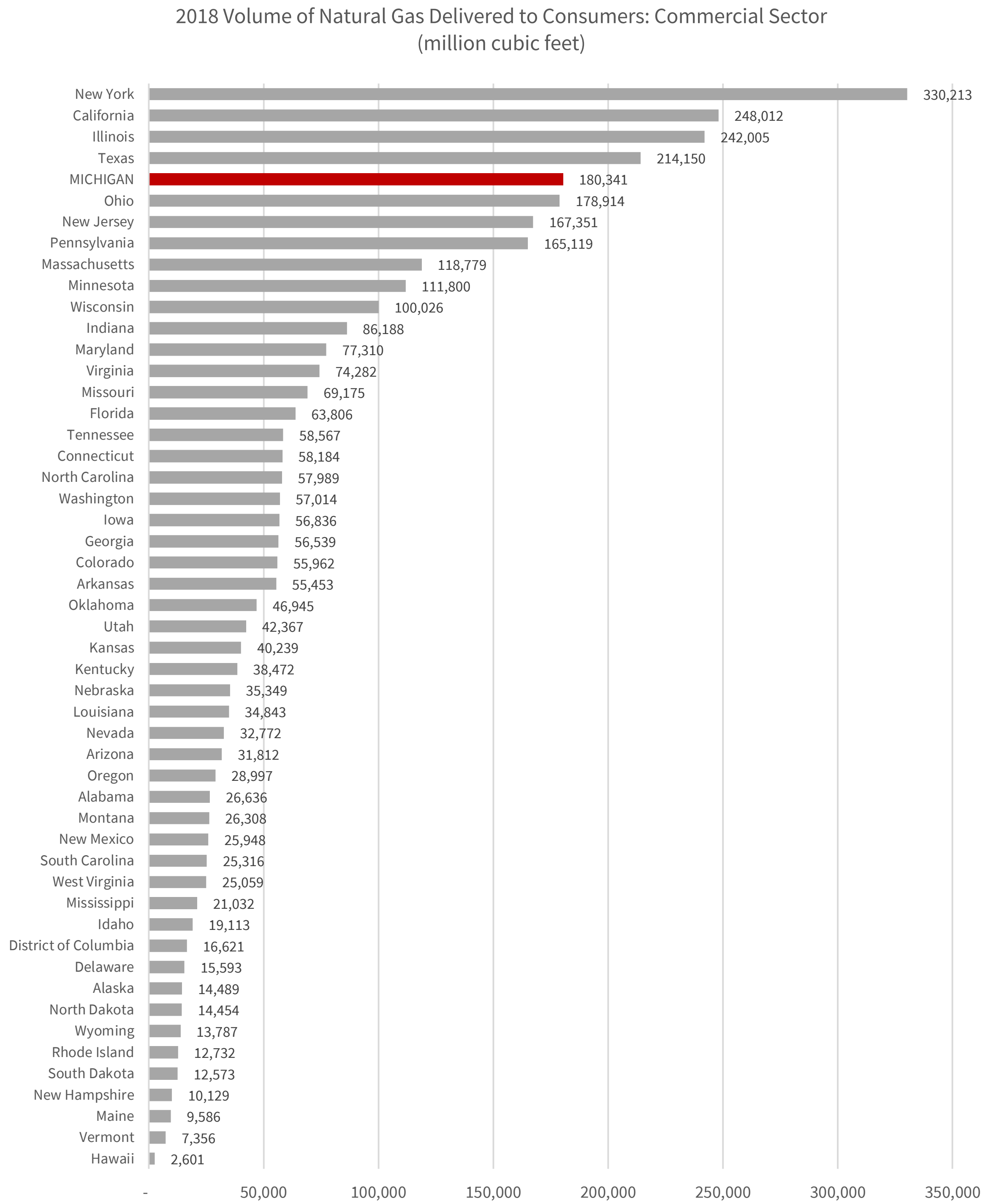


Figure 76: Commercial Gas Volume

Volume of Natural Gas Delivered to Consumers: Commercial Sector (thousand cubic feet)											
State	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR
New York	280,763	287,389	291,118	270,232	300,776	320,168	311,207	302,572	310,316	330,213	2%
California	247,775	247,997	246,141	253,148	254,845	237,675	235,791	236,967	237,352	248,012	0%
Illinois	222,768	198,036	215,605	188,099	230,820	246,273	215,218	212,482	215,936	242,005	1%
Texas	167,315	188,796	184,475	161,273	173,809	184,908	175,883	164,306	164,811	214,150	2%
MICHIGAN	163,683	152,350	163,567	144,609	171,519	186,413	168,360	158,613	162,634	180,341	1%
Ohio	160,612	156,407	161,408	145,482	168,233	183,105	166,602	152,478	156,979	178,914	1%
New Jersey	180,404	181,480	191,808	174,641	171,797	202,201	163,223	153,096	148,948	167,351	-1%
Pennsylvania	144,092	141,699	141,173	126,936	149,114	159,636	152,091	142,724	145,912	165,119	1%
Massachusetts	71,546	72,053	81,068	73,040	99,781	105,801	105,171	104,850	109,470	118,779	5%
Minnesota	96,218	89,963	94,360	83,174	105,937	110,884	93,005	92,591	99,756	111,800	2%
Wisconsin	91,459	82,204	87,040	76,949	99,434	107,003	90,175	88,679	90,470	100,026	1%
Indiana	78,764	75,883	75,995	66,663	82,596	90,915	77,552	74,131	75,312	86,188	1%
Maryland	69,119	67,555	67,505	64,146	71,145	74,843	70,199	70,500	72,279	77,310	1%
Virginia	67,709	68,911	64,282	60,217	68,126	72,165	69,107	67,553	68,162	74,282	1%
Missouri	61,433	61,194	62,304	54,736	64,522	72,919	61,389	56,968	57,903	69,175	1%
Florida	50,371	54,065	53,532	54,659	59,971	62,612	60,233	62,526	61,313	63,806	2%
Tennessee	51,879	56,194	52,156	44,928	53,888	57,435	53,049	49,809	49,042	58,567	1%
Connecticut	39,731	40,656	44,832	42,346	46,418	51,221	52,453	50,258	52,513	58,184	4%
North Carolina	51,303	56,225	49,898	48,951	55,271	59,945	55,114	55,876	53,726	57,989	1%
Washington	55,697	51,335	56,487	53,420	55,805	54,457	49,939	51,634	60,096	57,014	0%
Iowa	56,698	51,674	51,875	43,767	56,592	57,439	49,165	49,414	49,710	56,836	0%
Georgia	53,627	60,153	56,602	51,918	57,195	59,052	53,745	51,327	49,193	56,539	1%
Colorado	62,441	57,658	55,843	51,795	58,787	58,008	53,968	54,265	52,735	55,962	-1%
Arkansas	36,373	40,232	39,986	41,435	47,636	50,673	47,651	45,810	47,496	55,453	4%
Oklahoma	41,421	41,822	40,393	36,106	44,238	47,041	41,982	37,064	37,833	46,945	1%
Utah	37,024	38,461	40,444	35,363	41,398	38,156	35,772	39,066	41,264	42,367	1%
Kansas	32,512	31,799	32,117	25,452	33,198	36,154	37,047	34,757	34,612	40,239	2%
Kentucky	35,438	36,818	34,592	30,771	37,422	39,967	35,435	33,520	32,796	38,472	1%
Nebraska	31,790	31,993	32,115	26,503	32,214	32,407	29,464	26,971	29,018	35,349	1%
Louisiana	23,672	27,009	25,925	26,294	28,875	31,277	30,270	28,931	28,322	34,843	4%
Nevada	29,531	29,475	30,763	28,991	31,211	29,105	29,873	31,125	32,200	32,772	1%
Arizona	32,196	31,945	32,633	31,530	32,890	30,456	30,536	34,010	31,212	31,812	0%
Oregon	29,744	27,246	30,359	28,805	30,566	28,377	25,602	26,667	31,763	28,997	0%
Alabama	24,293	27,071	25,144	21,551	25,324	27,534	25,162	23,552	22,915	26,636	1%
Montana	23,575	20,459	22,336	19,205	20,971	21,549	19,502	21,314	23,374	26,308	1%
New Mexico	24,701	25,155	25,035	24,898	26,790	25,693	25,038	24,954	23,624	25,948	0%
South Carolina	21,953	24,119	22,113	21,416	23,862	25,398	23,752	23,734	22,931	25,316	1%
West Virginia	23,761	24,907	24,094	22,634	24,252	24,101	23,026	22,698	22,421	25,059	1%
Mississippi	19,095	21,179	20,247	17,834	19,483	22,195	19,727	18,135	17,643	21,032	1%
Idaho	15,740	15,033	16,855	15,838	18,485	16,963	16,708	17,598	19,777	19,113	2%
District of Columbia	18,705	18,547	16,892	15,363	17,234	17,498	17,113	15,648	16,040	16,621	-1%
Delaware	11,684	12,193	10,478	10,034	11,170	11,882	11,731	12,340	13,380	15,593	3%
Alaska	16,620	15,920	19,399	19,898	18,694	17,925	18,472	15,953	15,544	14,489	-1%
North Dakota	10,987	10,302	10,973	10,364	13,236	13,999	12,317	11,810	12,957	14,454	3%
Wyoming	10,372	11,153	11,680	10,482	12,013	12,188	12,937	13,425	13,972	13,787	3%
Rhode Island	10,725	10,458	10,843	10,090	11,633	13,178	12,016	10,744	11,338	12,732	2%
South Dakota	11,563	11,025	11,101	9,330	12,151	12,310	10,434	10,439	10,813	12,573	1%
New Hampshire	9,935	8,406	8,890	8,130	9,204	9,412	9,630	8,509	9,078	10,129	0%
Maine	5,541	5,830	6,593	7,313	8,146	9,030	10,072	8,559	8,925	9,586	6%
Vermont	2,483	2,384	2,479	2,314	4,748	4,830	5,918	6,251	6,205	7,356	11%
Hawaii	1,752	1,777	1,768	1,850	1,873	1,931	1,908	2,384	2,446	2,601	4%

Industrial Gas Volume

Figure 77 shows Michigan ranked 11th highest in Industrial natural gas usage in 2018.

Figure 77: 2018 Industrial Gas Volume

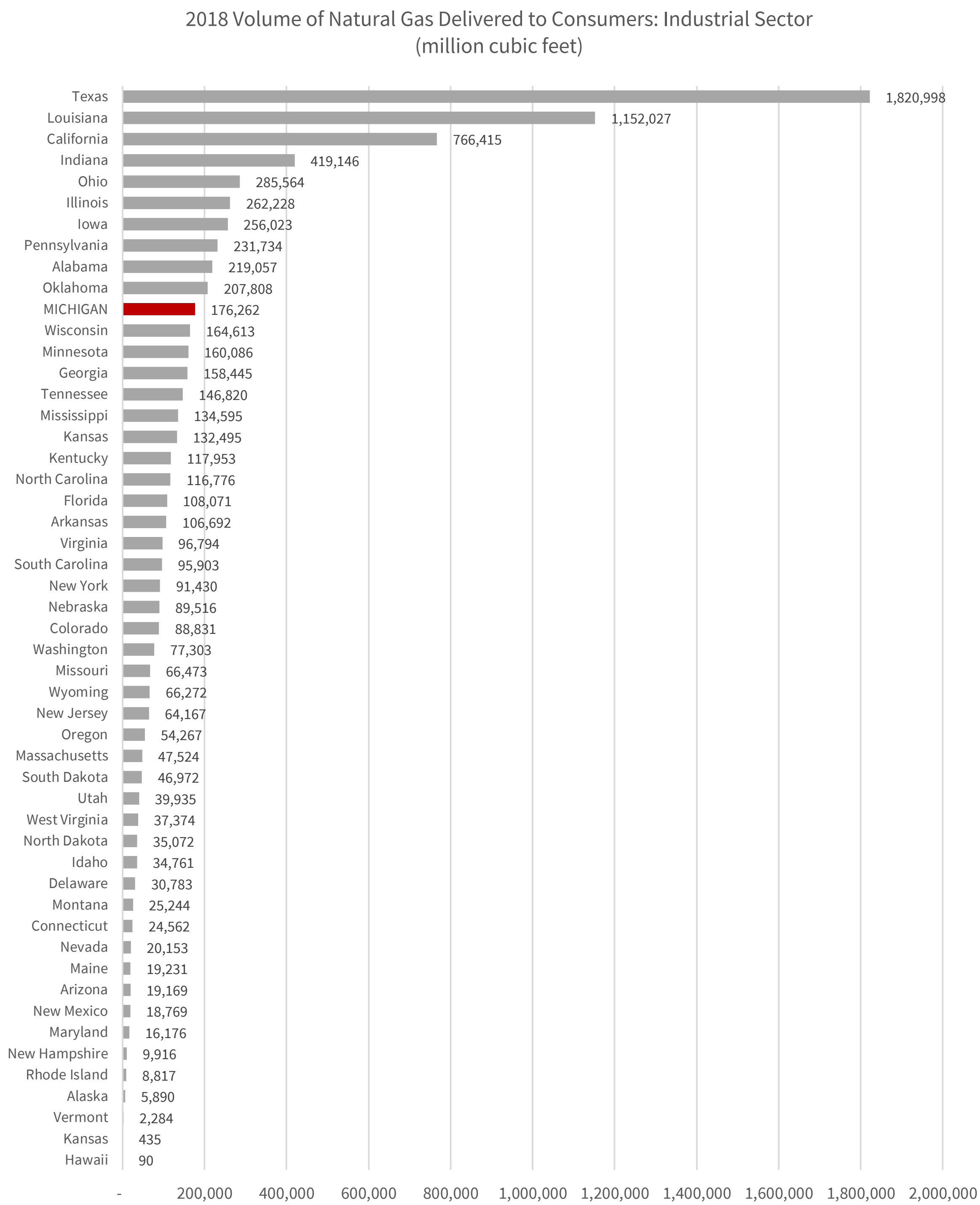


Figure 78: Industrial Gas Volume

State	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR
Texas	1,198,472	1,418,780	1,464,681	1,526,812	1,544,083	1,585,742	1,606,000	1,649,759	1,681,643	1,820,998	4%
Louisiana	761,468	864,534	886,158	955,750	932,425	960,033	949,421	1,048,751	1,096,400	1,152,027	4%
California	706,154	703,536	706,350	735,925	775,969	788,817	777,102	774,503	760,661	766,415	1%
Indiana	244,975	289,314	326,573	344,678	356,690	375,788	372,537	370,944	379,118	419,146	6%
Ohio	232,632	269,287	268,034	264,405	274,020	303,366	276,004	275,358	277,767	285,564	2%
Illinois	235,042	281,406	278,498	272,059	288,875	294,220	265,900	254,682	258,841	262,228	1%
Iowa	164,512	167,423	167,233	168,907	173,545	172,142	178,772	189,618	241,187	256,023	5%
Pennsylvania	173,323	200,016	199,594	200,169	215,406	237,013	212,050	212,253	219,028	231,734	3%
Alabama	131,228	144,938	153,358	171,729	179,511	187,661	186,819	192,424	196,654	219,057	5%
Oklahoma	177,521	185,909	193,001	184,005	180,809	183,874	184,547	193,703	199,576	207,808	2%
MICHIGAN	128,504	143,351	151,083	158,591	170,833	180,829	171,196	172,006	170,189	176,262	3%
Wisconsin	119,711	121,408	126,856	124,338	136,034	141,661	136,709	144,801	154,920	164,613	3%
Minnesota	128,361	158,457	157,776	159,947	160,732	173,569	157,401	162,818	165,901	160,086	2%
Georgia	140,326	146,737	144,940	146,481	157,982	160,842	157,937	152,311	150,172	158,445	1%
Tennessee	83,315	94,320	106,522	105,046	110,475	116,882	114,682	122,953	134,555	146,820	6%
Mississippi	99,252	115,489	112,959	111,995	114,198	117,908	121,835	116,105	128,356	134,595	3%
Kansas	107,569	108,484	113,356	114,720	116,778	118,590	121,064	124,071	127,653	132,495	2%
Kentucky	93,360	101,497	103,517	105,554	110,260	116,646	116,524	115,201	113,582	117,953	2%
North Carolina	82,253	92,321	99,110	102,151	109,662	107,904	105,103	105,504	107,373	116,776	4%
Florida	65,500	76,522	85,444	98,144	97,819	94,479	96,124	103,658	103,417	108,071	5%
Arkansas	77,585	83,061	85,437	81,597	87,077	88,797	85,287	87,876	100,256	106,692	3%
Virginia	57,144	62,243	66,147	71,486	75,998	81,040	86,817	88,422	94,098	96,794	5%
South Carolina	64,655	73,397	76,973	81,165	83,730	83,443	84,898	88,148	91,644	95,903	4%
New York	72,166	75,475	75,162	74,133	79,776	84,255	83,058	80,850	82,849	91,430	2%
Nebraska	80,873	85,180	86,128	85,439	88,140	86,878	85,604	91,021	89,521	89,516	1%
Colorado	113,582	114,295	74,407	73,028	78,280	78,323	78,178	80,432	84,914	88,831	-2%
Washington	71,271	71,280	76,289	78,196	80,889	79,439	76,527	79,275	80,656	77,303	1%
Missouri	63,431	65,554	63,053	62,516	63,212	67,115	65,691	63,630	63,158	66,473	0%
Wyoming	37,654	43,059	45,462	51,190	48,387	47,153	47,667	52,810	54,512	66,272	6%
New Jersey	48,465	49,269	49,865	54,785	61,468	61,494	55,368	60,910	54,298	64,167	3%
Oregon	57,318	55,822	56,977	57,506	57,372	56,522	53,632	57,760	57,849	54,267	-1%
Massachusetts	39,400	44,239	47,590	43,928	46,677	45,581	44,554	45,721	47,004	47,524	2%
South Dakota	36,301	40,755	40,668	40,432	44,039	44,205	44,094	44,570	45,641	46,972	3%
Utah	29,845	32,079	33,633	36,350	38,009	38,330	37,189	38,568	40,007	39,935	3%
West Virginia	24,432	26,023	25,443	26,926	26,780	27,796	25,474	32,281	38,358	37,374	4%
North Dakota	15,680	23,762	28,303	26,680	27,812	27,762	31,660	31,232	32,127	35,072	8%
Idaho	24,256	24,195	25,392	29,781	27,996	28,046	31,664	34,761	35,856	34,761	4%
Delaware	17,402	7,983	19,760	28,737	32,154	31,004	33,126	31,457	29,860	30,783	6%
Montana	20,615	18,478	19,386	18,319	19,352	22,084	21,920	21,233	23,393	25,244	2%
Connecticut	24,585	24,117	26,258	26,932	29,965	28,371	25,612	24,271	24,557	24,562	0%
Nevada	11,458	10,728	11,080	11,299	13,209	16,432	17,724	18,327	19,269	20,153	6%
Maine	25,923	28,365	27,734	30,248	32,308	24,121	20,972	18,983	17,698	19,231	-3%
Arizona	17,948	19,245	21,724	22,657	22,153	22,489	20,402	19,765	19,250	19,169	1%
New Mexico	15,680	16,779	20,500	19,582	18,794	19,091	17,937	16,109	15,412	18,769	2%
Maryland	23,926	23,371	21,220	17,626	13,989	14,734	14,765	15,400	15,744	16,176	-4%
New Hampshire	4,688	6,022	7,083	7,007	7,866	8,456	8,386	8,454	9,499	9,916	8%
Rhode Island	7,739	8,033	7,462	7,841	8,161	8,008	8,624	8,474	8,551	8,817	1%
Alaska	6,635	6,408	6,769	6,357	4,065	4,847	4,864	4,268	4,156	5,890	-1%
Vermont	2,890	2,909	2,812	2,711	1,303	1,858	2,040	2,172	2,191	2,284	-2%
Kansas					23	19	457	459	371	435	
Hawaii	344	339	362	355	388	401	442	83	85	90	-13%

Losses

As shown in Figure 79, Michigan recorded the 10th highest amount of natural gas losses. As a percentage of total volume, losses amounted to 0.5%, 18th highest among states in 2018 as shown in Figure 80.

Figure 79: 2018 Natural Gas Losses

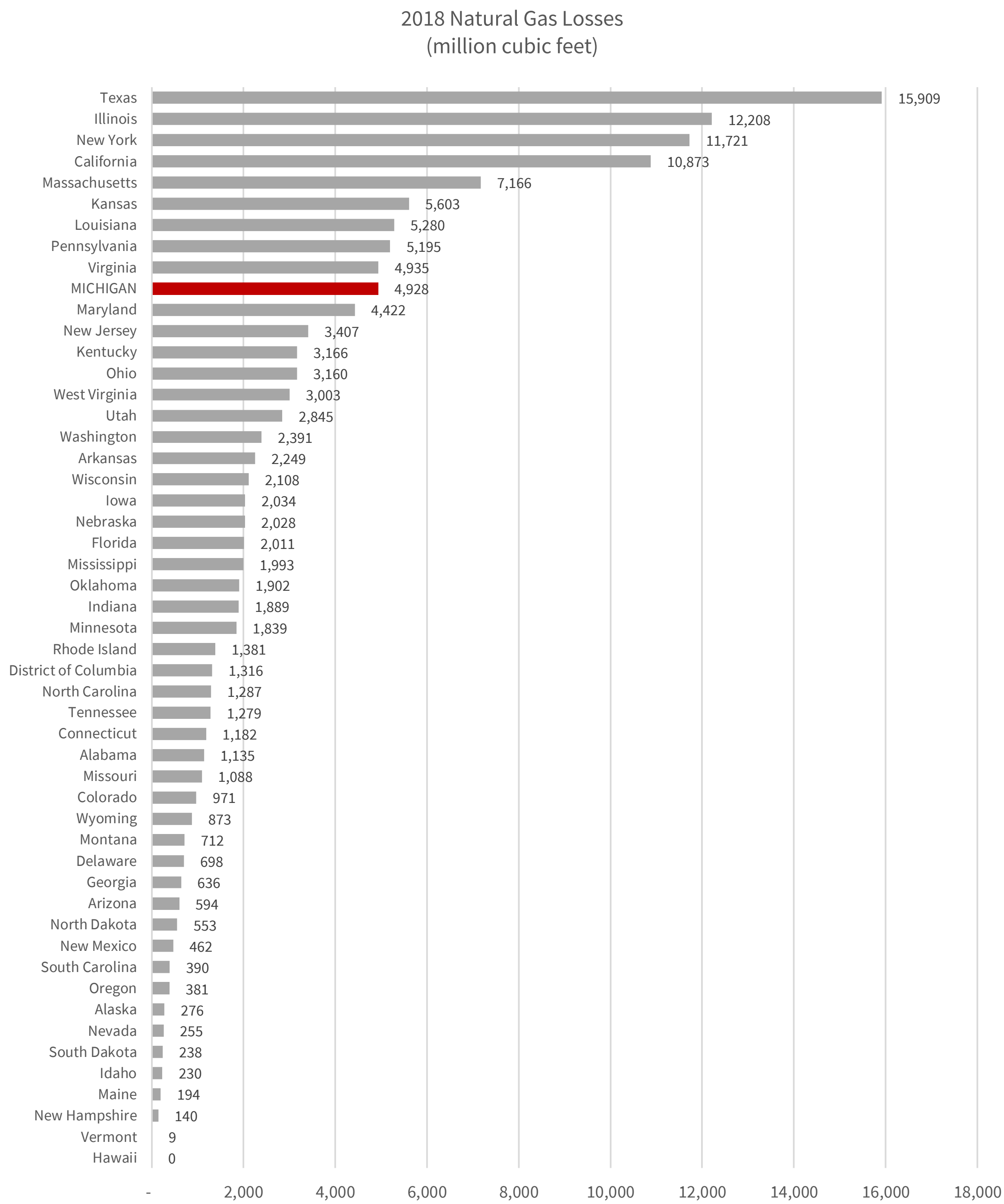
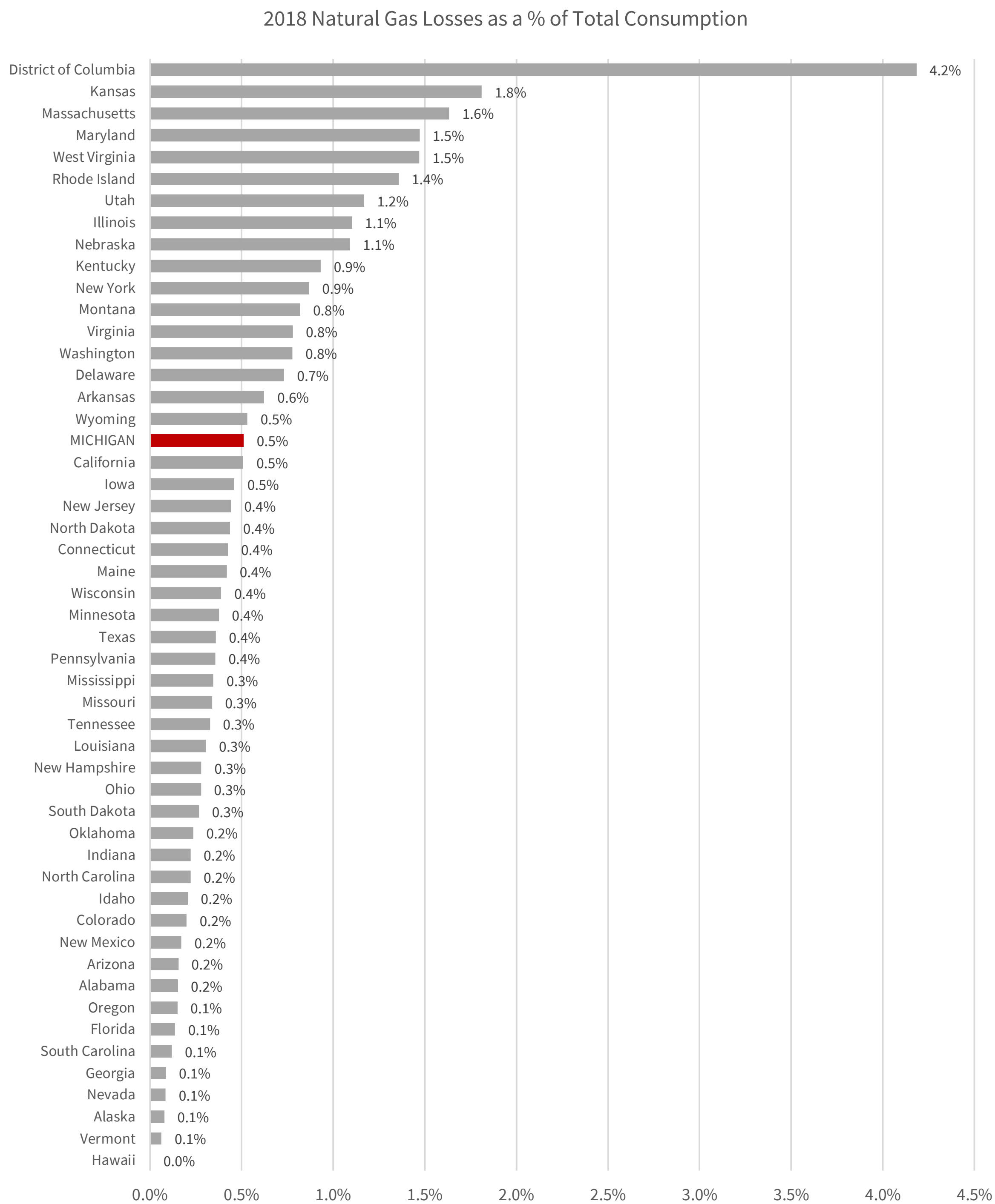


Figure 80: 2018 Natural Gas Losses as a percent of Total Consumption



Unaccounted

Unaccounted-for natural gas can take on positive or negative values, depending on the difference between total supply and total disposition. Note that the left-most portion of the scale in the following graphs displays negative values.

Figure 82 shows unaccounted-for gas amounted to only 0.45% of total consumption in Michigan in 2018, ranking 16th in the country. 4,307 thousand cubic feet were unaccounted for in Michigan, 10th highest total among the states.

Figure 81: 2018 Unaccounted-for Natural Gas

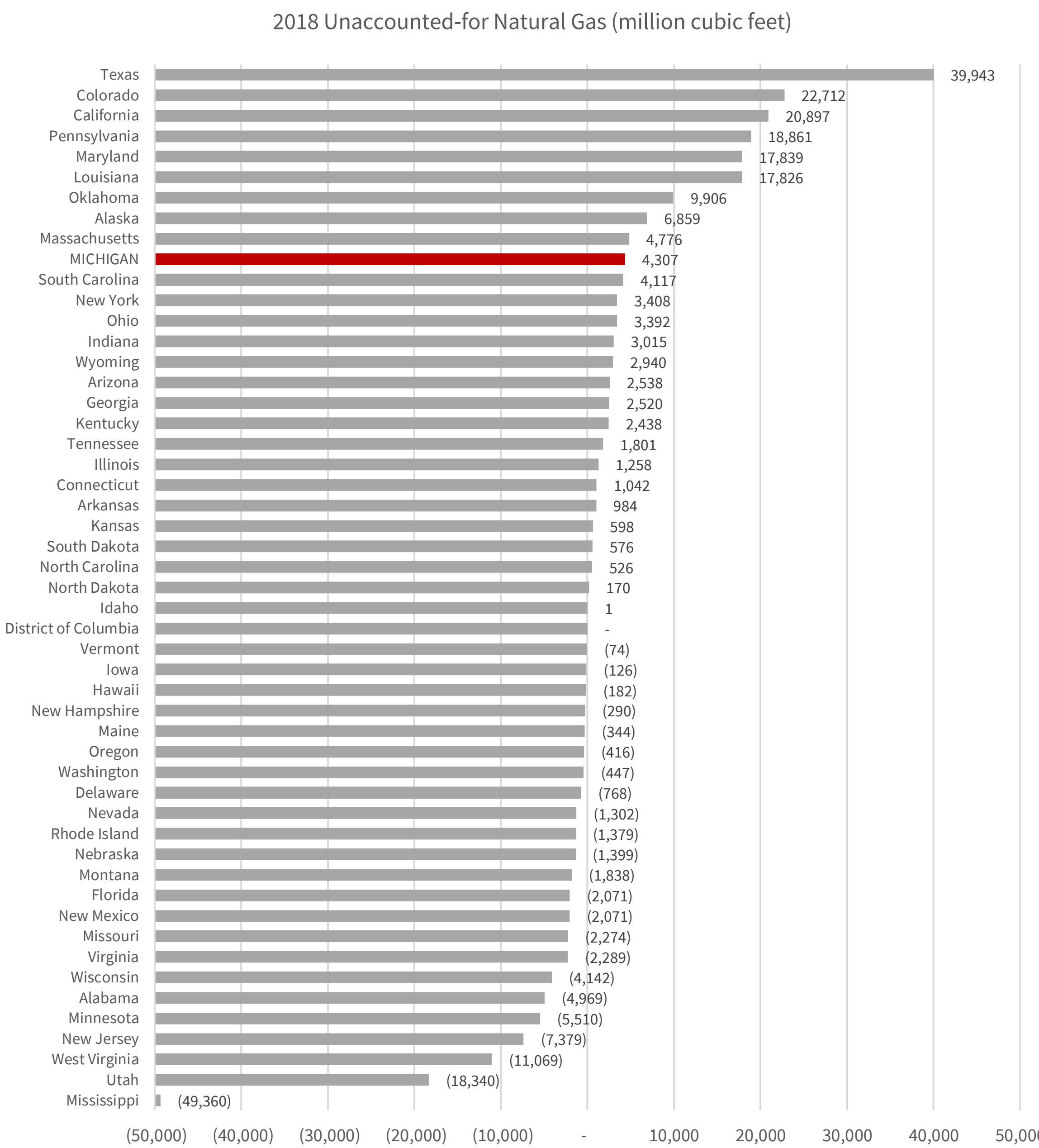
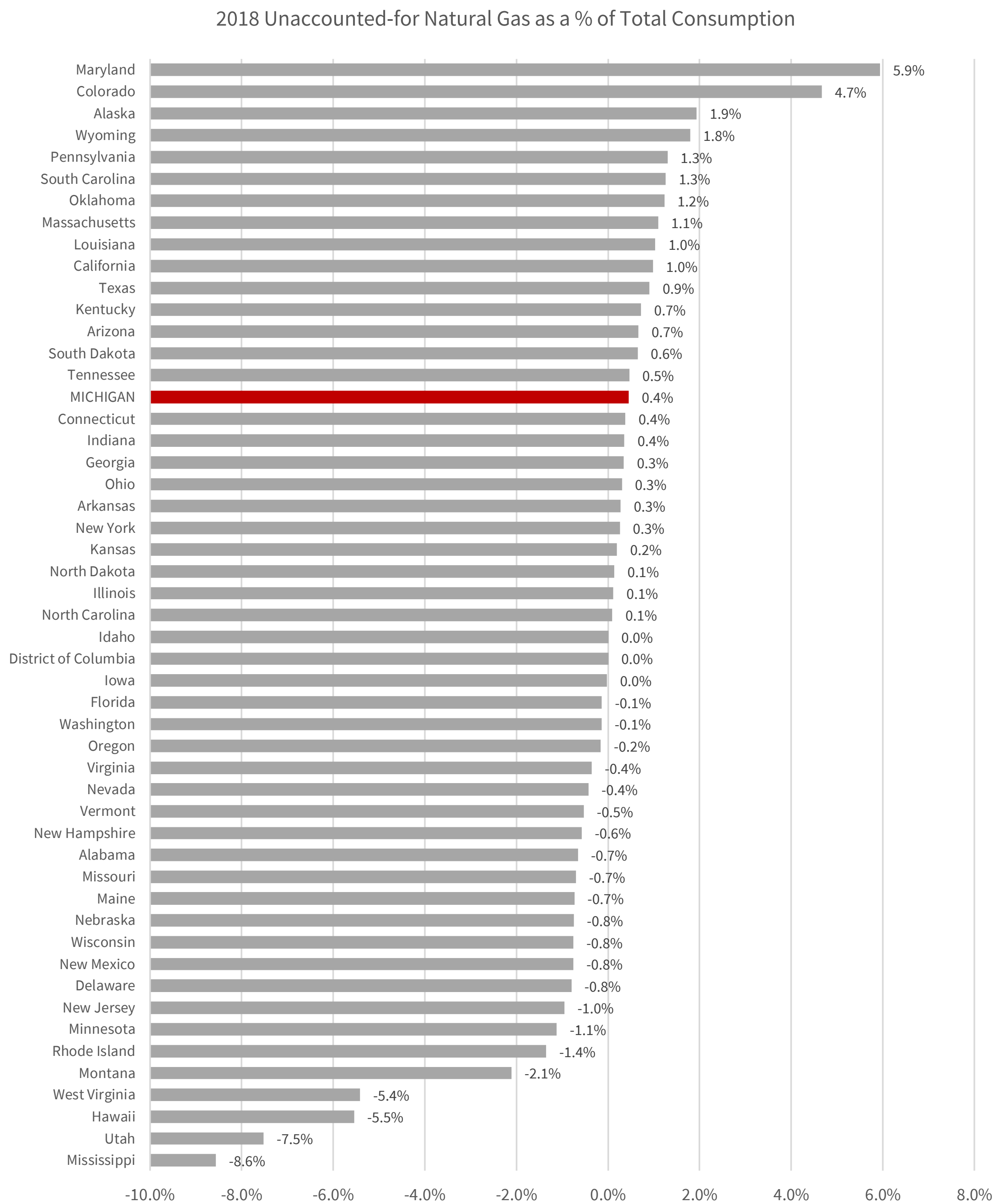


Figure 82: 2018 Unaccounted-for Natural Gas as a percent of Total Consumption



ELECTRIC UTILITY PERFORMANCE: EVALUATING MICHIGAN'S UTILITIES IN 2018

RELIABILITY

The following section displays reliability metrics for Michigan utilities.

Figure 83: 2018 Michigan Utilities SAIDI with MED

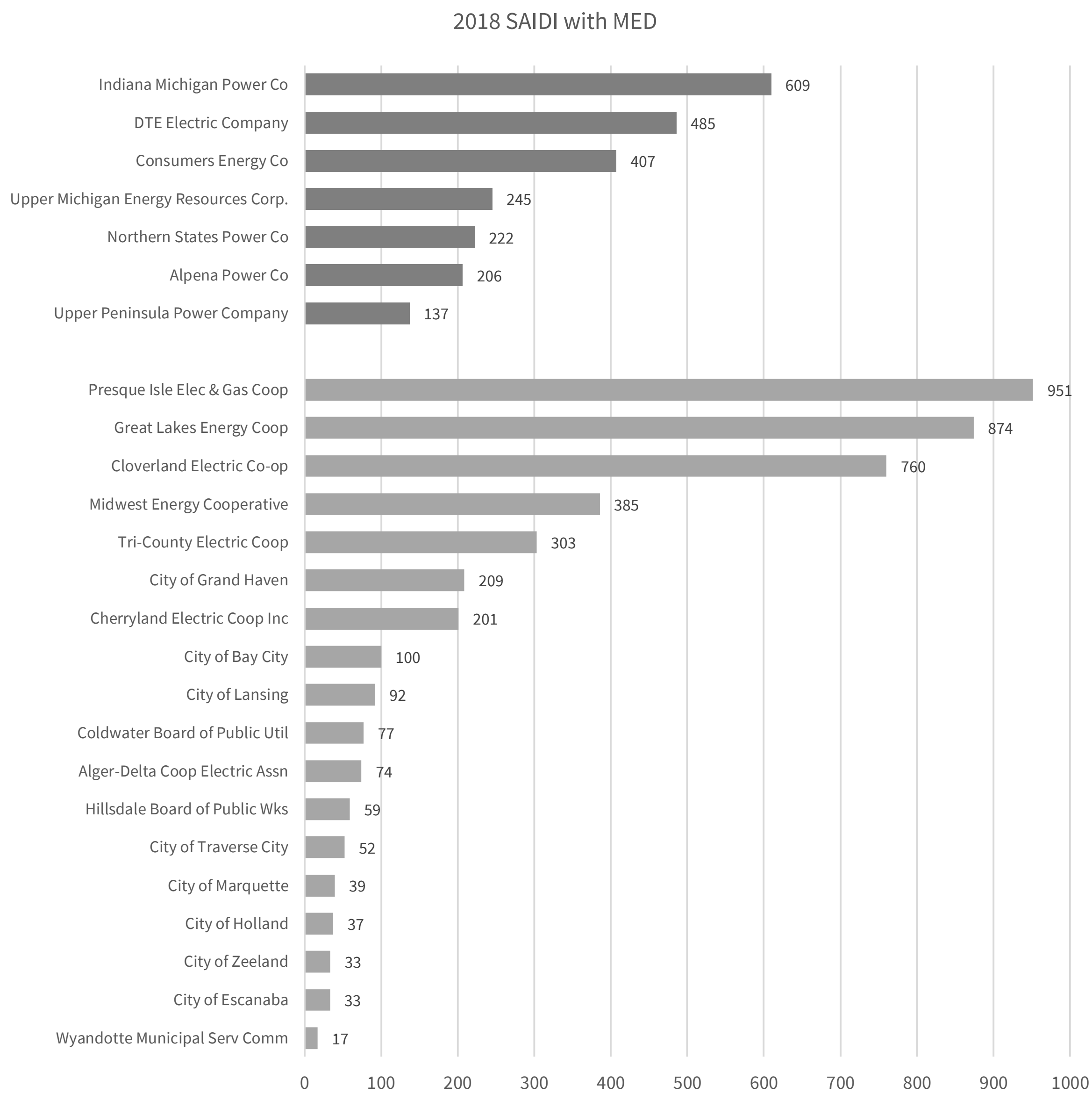


Figure 84: Michigan Utilities SAIDI with MED

SAIDI with MED						
Utility	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Indiana Michigan Power Co	1188	1079	526	561	442	609
DTE Electric Company	583	793	277	238	1063	485
Consumers Energy Co	1109	377	441	284	606	407
Upper Michigan Energy Resources Corp.					551	245
Northern States Power Co			157	436	348	222
Alpena Power Co		146	229	91	131	206
Upper Peninsula Power Company	297	281	161	457	603	137
Presque Isle Elec & Gas Coop	317	196	1367	442	883	951
Great Lakes Energy Coop	340	250	912	256	335	874
Cloverland Electric Co-op	350	608	879	436	871	760
Midwest Energy Cooperative	1069	587	107	371	563	385
Tri-County Electric Coop	1057	724	281	519	232	303
City of Grand Haven		67	52	155	605	209
Cherryland Electric Coop Inc	83	75	78	74	109	201
City of Bay City				55	99	100
City of Lansing		166	139	305	283	92
Coldwater Board of Public Util	37	61	33	82	69	77
Alger-Delta Coop Electric Assn	53	751	108	82	335	74
Hillsdale Board of Public Wks				66	76	59
City of Traverse City					35	52
City of Marquette		86	30	34	109	39
City of Holland	55	39	28	50	35	37
City of Zeeland			40	6	27	33
City of Escanaba		89	538	27	33	33
Wyandotte Municipal Serv Comm	25	55	24	19	1	17

Figure 85: 2018 Michigan Utilities SAIDI without MED

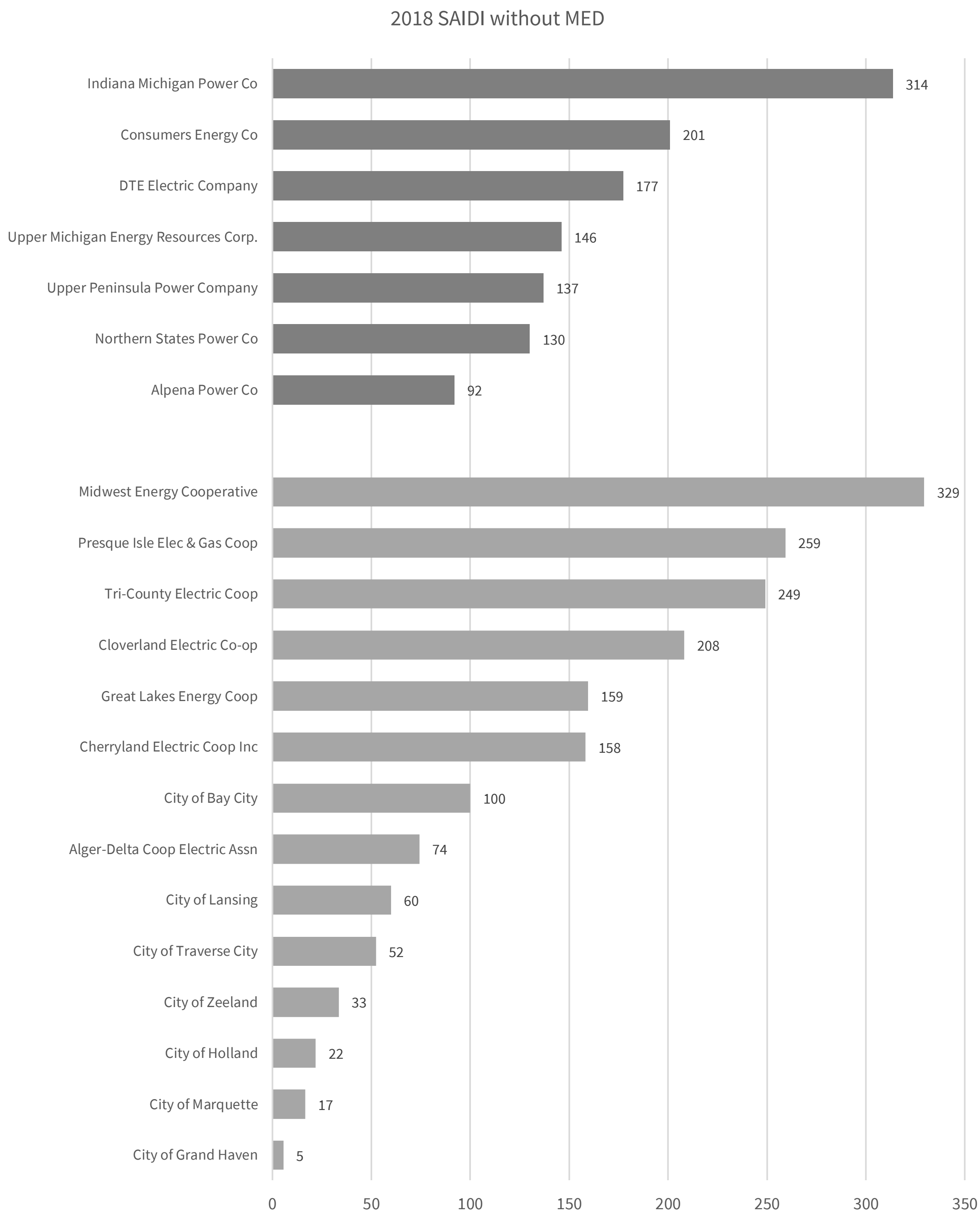


Figure 86: Michigan Utilities SAIDI without MED

SAIDI without MED						
Utility	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Indiana Michigan Power Co	268	287	311	373	304	314
Consumers Energy Co	218	168	177	207	161	201
DTE Electric Company	180	189	187	180	196	177
Upper Michigan Energy Resources Corp.					149	146
Upper Peninsula Power Company	248	248	122	165	176	137
Northern States Power Co			157	283	135	130
Alpena Power Co		64	97	91	66	92
Midwest Energy Cooperative	462	291	107	371	452	329
Presque Isle Elec & Gas Coop	180	196	227	275	288	259
Tri-County Electric Coop	259	243	179	179	139	249
Cloverland Electric Co-op	284	254	210	352	208	208
Great Lakes Energy Coop	177	136	175	160	178	159
Cherryland Electric Coop Inc	83	75	78	74	69	158
City of Bay City				55	99	100
Alger-Delta Coop Electric Assn	52	476	107	75	73	74
City of Lansing		81	43	113	68	60
City of Traverse City					35	52
City of Zeeland			40	6	27	33
City of Holland	35	28	18	19	21	22
City of Marquette	50	86	21	34	109	17
City of Grand Haven	275	0	0	155	6	5

Figure 87: 2018 Michigan Utilities SAIFI with MED

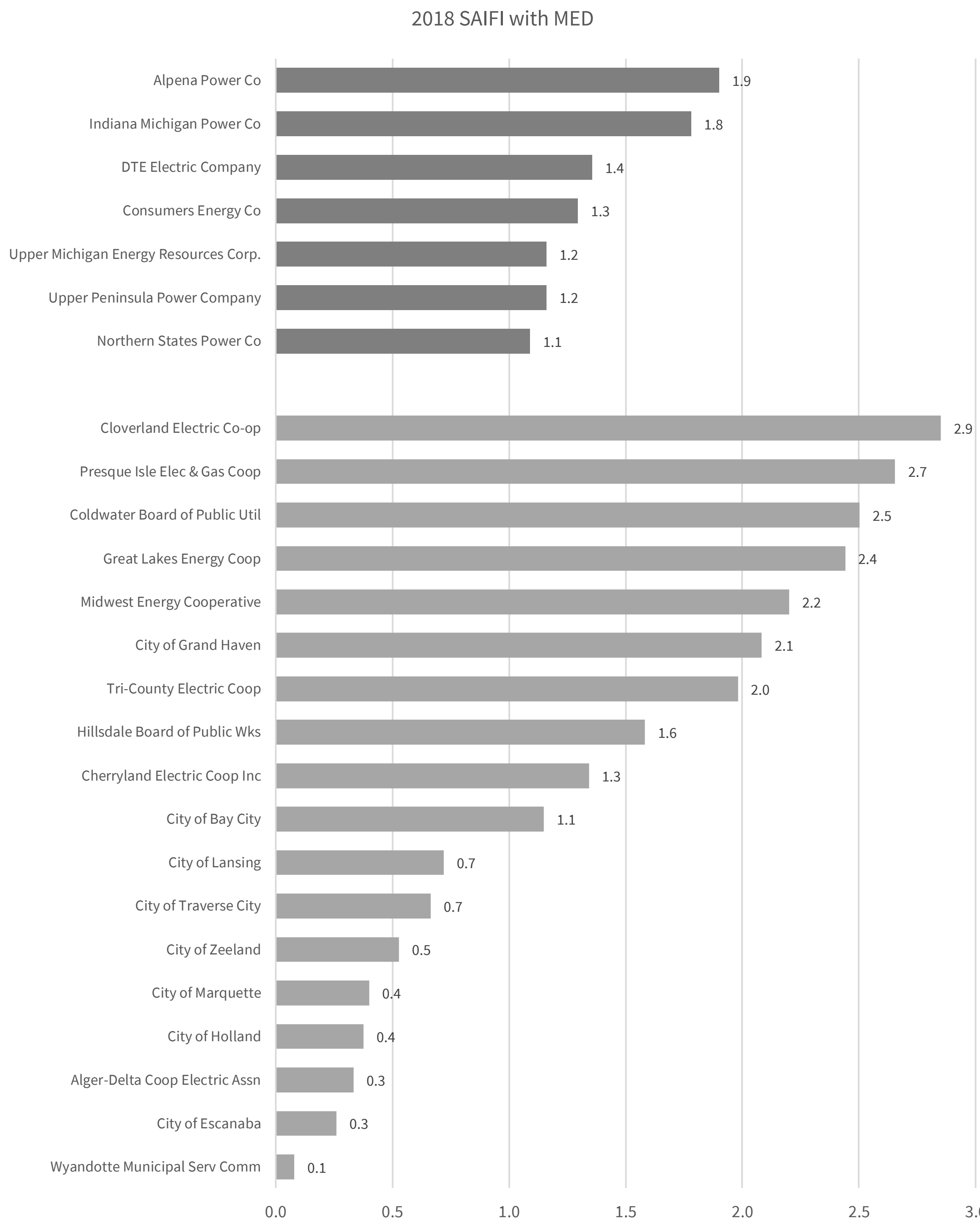


Figure 88: Michigan Utilities SAIFI with MED

SAIFI with MED						
Utility	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Alpena Power Co		1.0	1.5	1.2	1.2	1.9
Indiana Michigan Power Co	1.8	1.7	1.7	1.9	2.0	1.8
DTE Electric Company	1.1	1.2	1.0	1.0	1.4	1.4
Consumers Energy Co	2.0	1.1	1.2	1.2	1.3	1.3
Upper Michigan Energy Resources Corp.					1.9	1.2
Upper Peninsula Power Company	2.0	1.9	1.3	2.1	2.2	1.2
Northern States Power Co			1.0	2.3	1.3	1.1
Cloverland Electric Co-op	1.9	2.8	2.1	2.4	3.2	2.9
Presque Isle Elec & Gas Coop	1.4	1.3	2.3	1.8	2.8	2.7
Coldwater Board of Public Util	0.6	0.9	0.7	1.7	1.0	2.5
Great Lakes Energy Coop	1.9	1.5	2.3	1.8	2.1	2.4
Midwest Energy Cooperative	3.0	2.2	1.0	1.9	2.8	2.2
City of Grand Haven		0.8	0.4	2.1	2.1	2.1
Tri-County Electric Coop	2.1	2.5	1.7	1.8	1.5	2.0
Hillsdale Board of Public Wks				2.4	0.9	1.6
Cherryland Electric Coop Inc	0.6	0.6	0.7	0.7	0.8	1.3
City of Bay City				0.5	0.6	1.1
City of Lansing		0.9	1.1	1.7	1.0	0.7
City of Traverse City					0.4	0.7
City of Zeeland			1.0	0.5	1.2	0.5
City of Marquette		1.2	0.4	0.5	0.9	0.4
City of Holland	0.6	0.6	0.4	0.5	0.5	0.4
Alger-Delta Coop Electric Assn	0.3	1.7	1.1	0.4	1.0	0.3
City of Escanaba	1.0	0.6	1.0	0.2	0.3	0.3
Wyandotte Municipal Serv Comm	0.3	0.4	0.0	0.2	0.0	0.1

Figure 89: 2018 Michigan Utilities SAIFI without MED

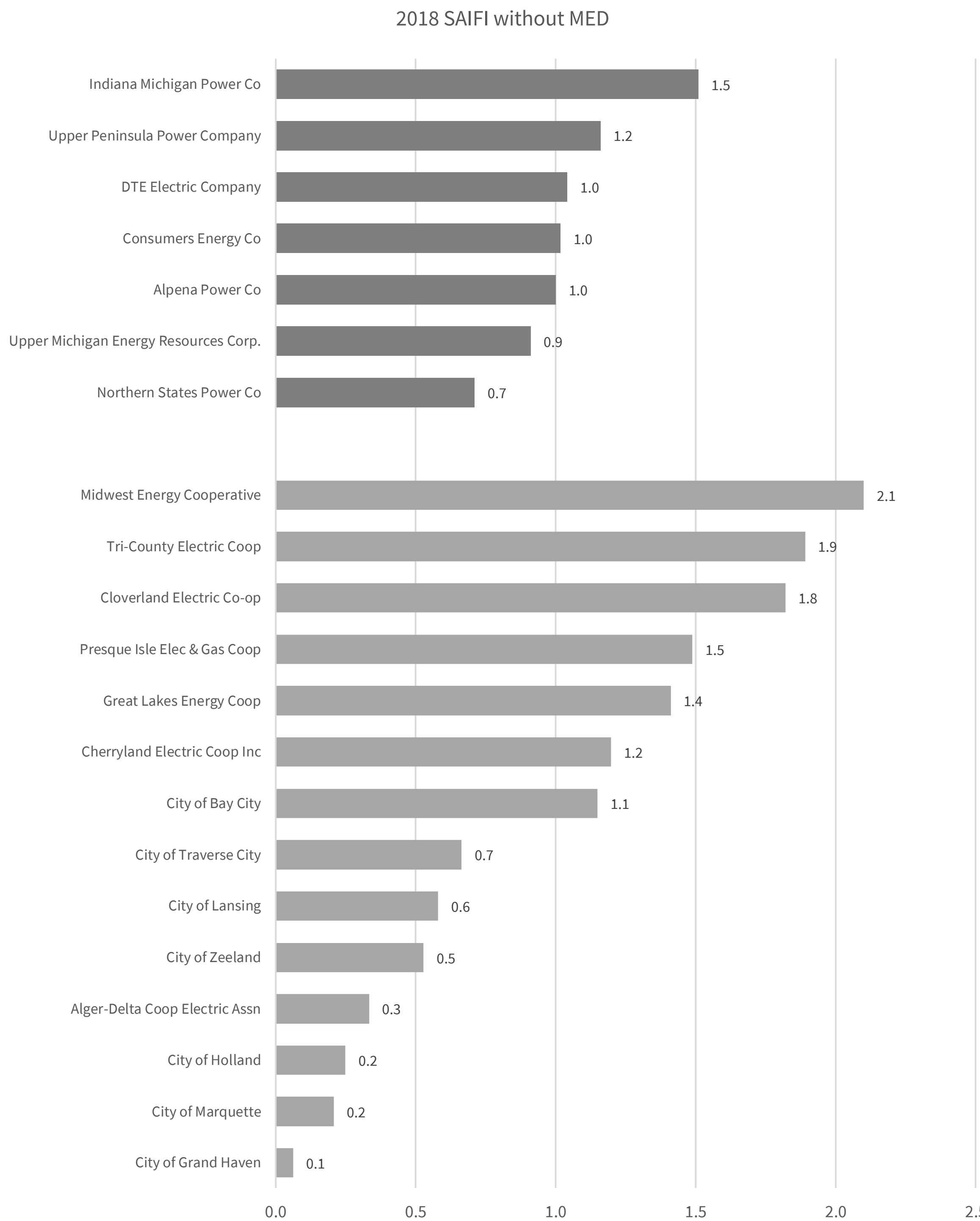


Figure 90: Michigan Utilities SAIFI without MED

SAIFI without MED						
Utility	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Indiana Michigan Power Co	1.3	1.3	1.5	1.7	1.7	1.5
Upper Peninsula Power Company	2.0	1.8	1.1	1.3	1.3	1.2
DTE Electric Company	0.7	0.8	0.9	0.9	1.0	1.0
Consumers Energy Co	1.0	0.9	1.0	1.0	0.9	1.0
Alpena Power Co		0.6	1.1	1.2	0.8	1.0
Upper Michigan Energy Resources Corp.					1.0	0.9
Northern States Power Co			1.0	2.1	0.9	0.7
Midwest Energy Cooperative	2.0	1.9	1.0	1.9	2.5	2.1
Tri-County Electric Coop	1.6	2.2	1.5	1.5	1.3	1.9
Cloverland Electric Co-op	1.7	2.0	1.7	2.3	1.6	1.8
Presque Isle Elec & Gas Coop	1.0	1.3	1.3	1.4	1.5	1.5
Great Lakes Energy Coop	1.5	1.2	1.4	1.5	1.5	1.4
Cherryland Electric Coop Inc	0.6	0.6	0.7	0.7	0.6	1.2
City of Bay City				0.5	0.6	1.1
City of Traverse City					0.4	0.7
City of Lansing		0.8	0.5	1.0	0.7	0.6
City of Zeeland			1.0	0.5	1.2	0.5
Alger-Delta Coop Electric Assn		1.4	1.1	0.4	1.0	0.3
City of Holland	0.5	0.5	0.3	0.2	0.2	0.2
City of Marquette	0.7	1.2	0.3	0.5	0.9	0.2
City of Grand Haven	1.7	0.0	0.0	2.1	0.1	0.1

Figure 91: 2018 Michigan Utilities CAIDI with MED

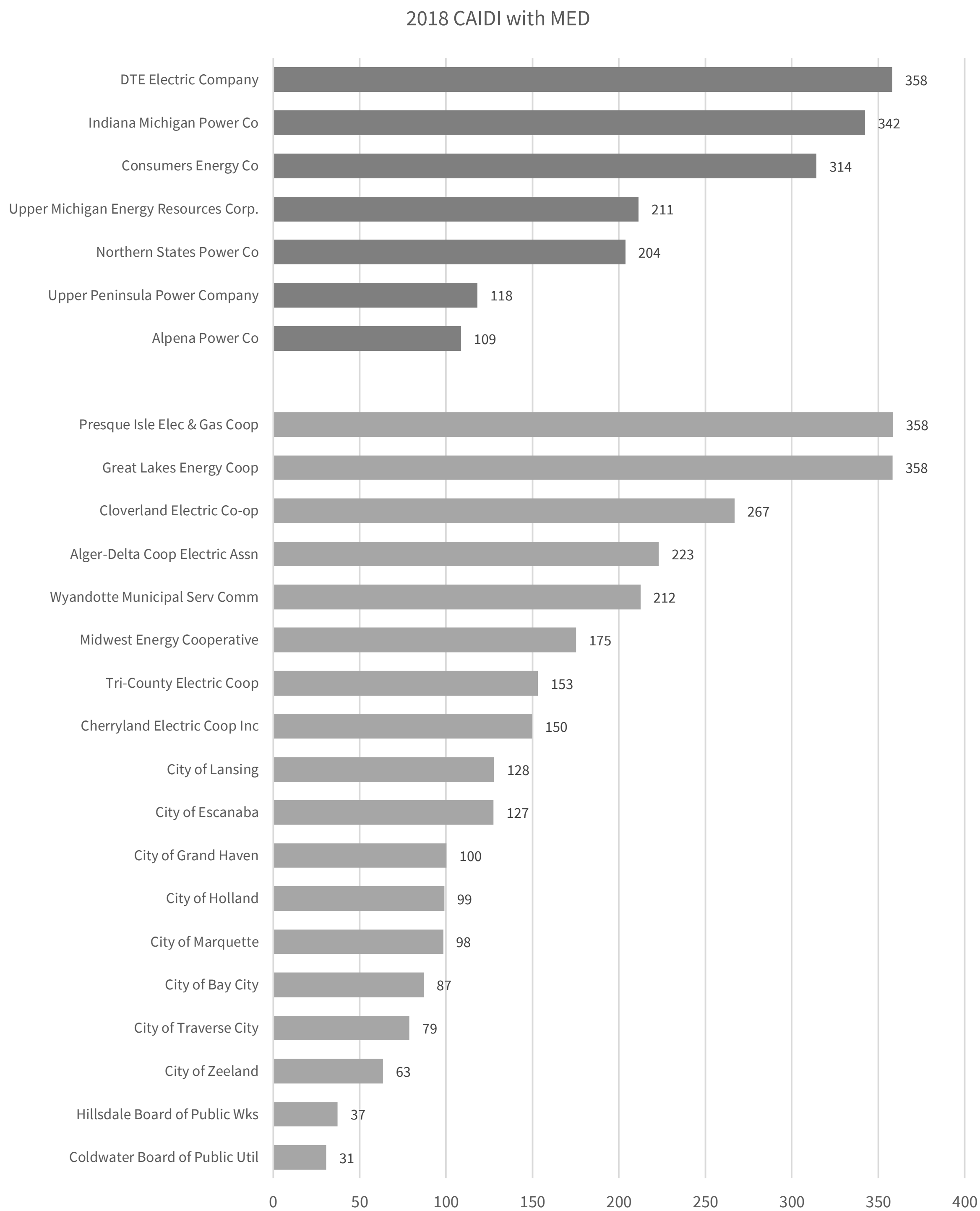


Figure 92: Michigan Utilities CAIDI with MED

CAIDI with MED						
Utility	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
DTE Electric Company	530	650	277	241	765	358
Indiana Michigan Power Co	655	640	302	294	219	342
Consumers Energy Co	555	342	373	247	462	314
Upper Michigan Energy Resources Corp.					298	211
Northern States Power Co			157	186	264	204
Upper Peninsula Power Company	149	152	124	218	274	118
Alpena Power Co		146	153	76	109	109
Presque Isle Elec & Gas Coop	230	148	595	244	321	358
Great Lakes Energy Coop	184	169	402	141	162	358
Cloverland Electric Co-op	182	214	424	179	275	267
Alger-Delta Coop Electric Assn	191	449	99	204	339	223
Wyandotte Municipal Serv Comm	89	138	800	96	199	212
Midwest Energy Cooperative	356	263	108	199	201	175
Tri-County Electric Coop	513	286	167	290	153	153
Cherryland Electric Coop Inc	146	121	107	110	134	150
City of Lansing		187	129	183	272	128
City of Escanaba		139	566	144	102	127
City of Grand Haven		84	119	75	289	100
City of Holland	97	68	71	108	71	99
City of Marquette		70	75	67	118	98
City of Bay City				106	160	87
City of Traverse City					82	79
City of Zeeland			38	11	23	63
Hillsdale Board of Public Wks				27	86	37
Coldwater Board of Public Util	66	66	46	49	67	31

Figure 93: 2018 Michigan Utilities CAIDI without MED

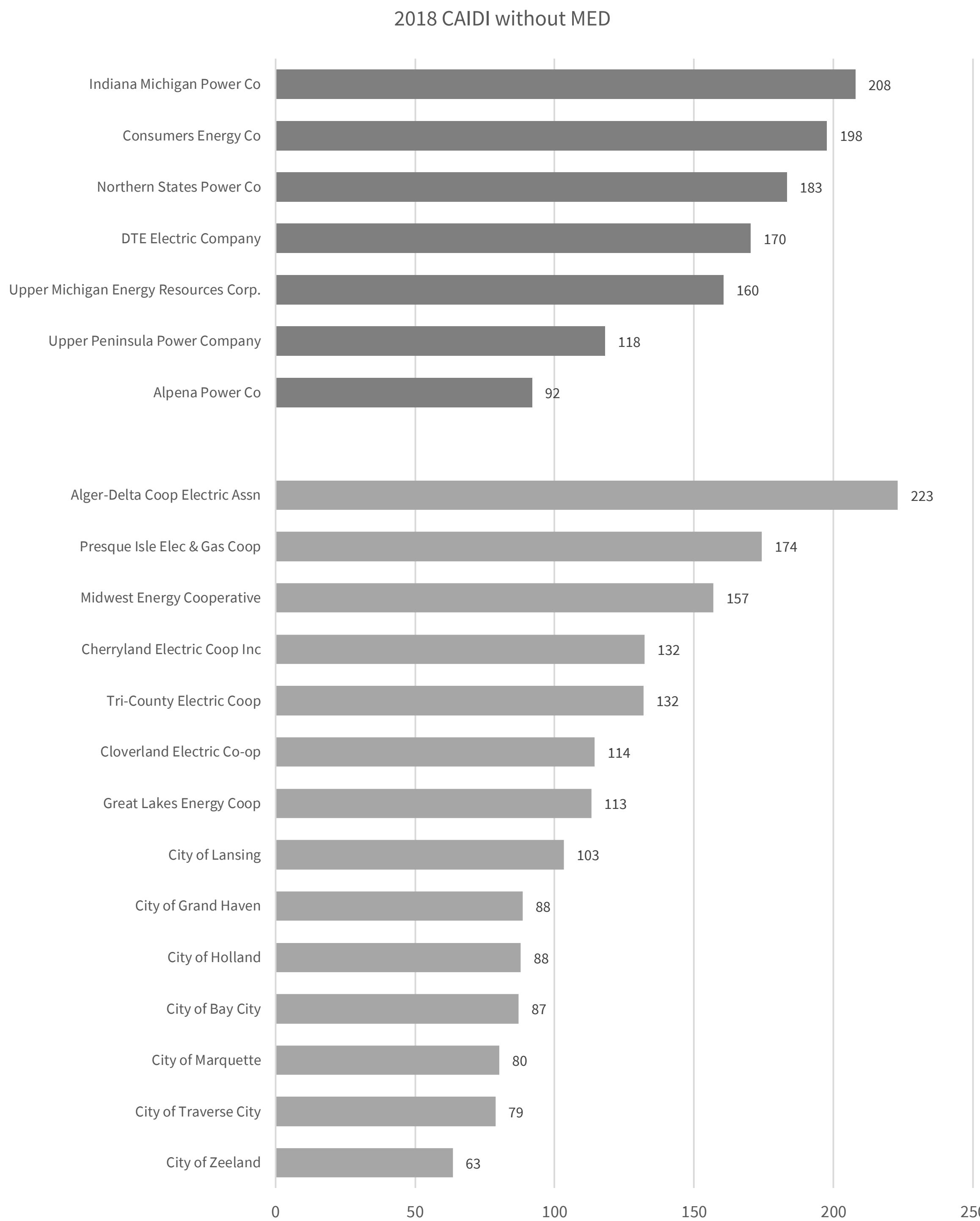


Figure 94: Michigan Utilities CAIDI without MED

CAIDI without MED						
Utility	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Indiana Michigan Power Co	207	221	212	217	174	208
Consumers Energy Co	218	184	180	206	181	198
Northern States Power Co			157	134	159	183
DTE Electric Company	244	249	205	197	198	170
Upper Michigan Energy Resources Corp.					152	160
Upper Peninsula Power Company	124	139	111	127	135	118
Alpena Power Co		107	88	76	82	92
Alger-Delta Coop Electric Assn		331	99	188	74	223
Presque Isle Elec & Gas Coop	172	148	172	191	191	174
Midwest Energy Cooperative	231	156	108	199	181	157
Cherryland Electric Coop Inc	146	121	107	110	121	132
Tri-County Electric Coop	162	109	120	123	104	132
Cloverland Electric Co-op	163	126	126	157	129	114
Great Lakes Energy Coop	120	114	130	110	119	113
City of Lansing		98	89	108	105	103
City of Grand Haven	163			75	89	88
City of Holland	75	57	57	79	89	88
City of Bay City				106	160	87
City of Marquette	74	70	71	67	118	80
City of Traverse City					82	79
City of Zeeland			38	11	23	63

AFFORDABILITY

Figure 95: 2018 Michigan Utilities Residential Electricity Price

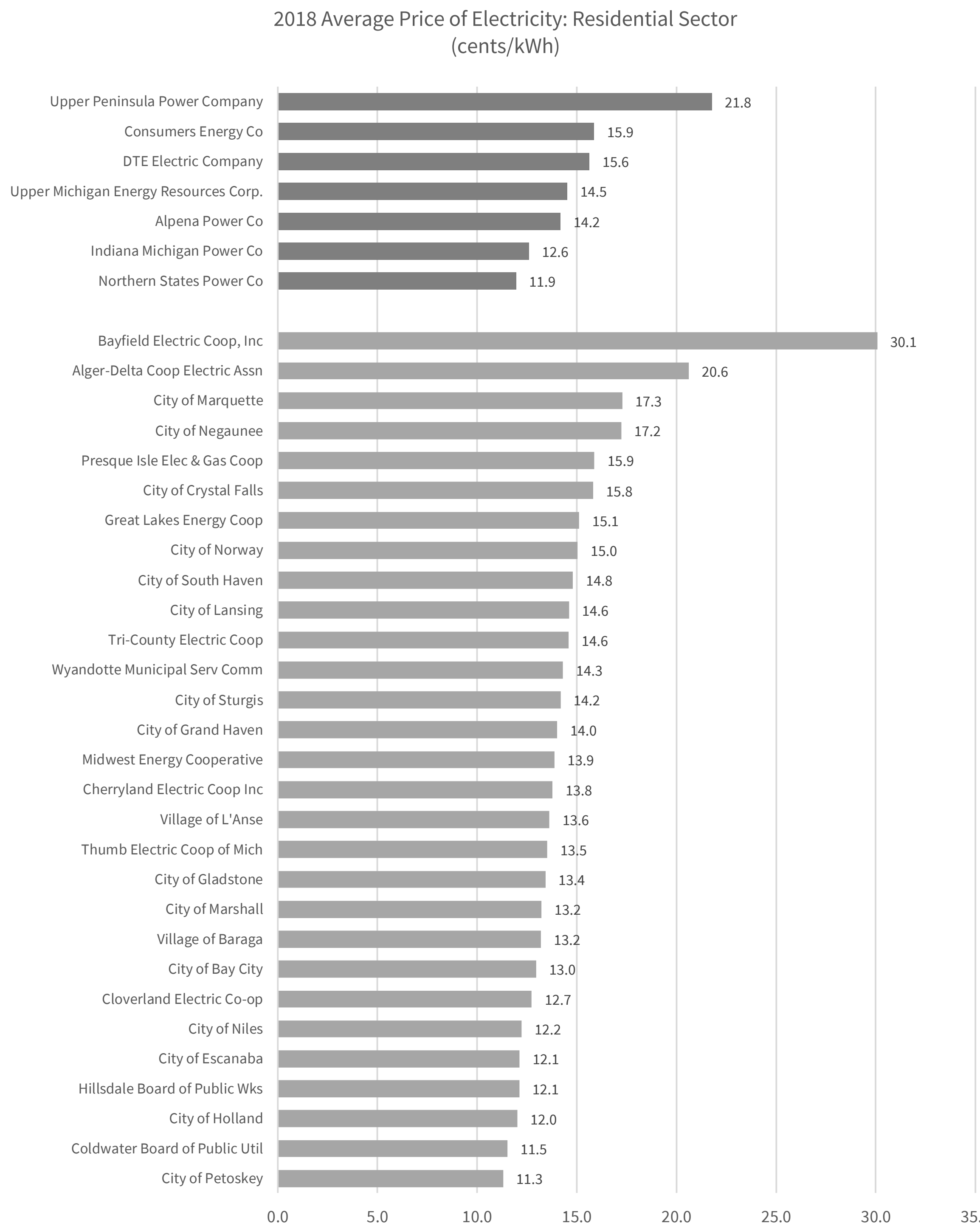


Figure 96: Michigan Utilities Residential Electricity Price

Average Price of Electricity: Residential Sector (cents/kWh)											
Utility	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR
Upper Peninsula Power Company	15.9	17.1	18.3	19.4	20.5	22.5	22.9	23.5	24.3	21.8	3%
Consumers Energy Co	11.7	12.9	13.4	13.7	14.4	14.9	14.6	15.4	15.9	15.9	3%
DTE Electric Company	12.0	12.6	13.7	15.0	15.4	14.6	14.5	15.6	15.5	15.6	3%
Upper Michigan Energy Resources Corp.									14.8	14.5	
Alpena Power Co	12.7	13.7	14.1	13.8	14.0	13.6	13.8	13.3	13.9	14.2	1%
Indiana Michigan Power Co	6.8	7.6	8.6	9.7	10.0	10.0	10.7	11.0	11.3	12.6	6%
Northern States Power Co	9.6	9.6	10.1	10.9	11.0	12.1	12.3	12.3	12.6	11.9	2%
Bayfield Electric Coop, Inc	20.0	23.0	25.0	28.3	28.7	28.6	30.7	29.4	29.4	30.1	4%
Alger-Delta Coop Electric Assn	18.3	20.1	20.3	21.3	20.6	20.8	20.9	20.7	20.6	20.6	1%
City of Marquette	8.9	9.3	9.3	10.0	10.4	11.1	11.9	13.8	17.1	17.3	7%
City of Negaunee	15.2	17.3	18.1	15.7	15.9	16.0	17.1	17.6	17.6	17.2	1%
Presque Isle Elec & Gas Coop	13.1	13.7	14.5	15.6	16.4	16.0	16.0	16.0	16.2	15.9	2%
City of Crystal Falls	11.8	14.9	14.9	15.4	15.3	15.2	15.8	15.5	15.9	15.8	3%
Great Lakes Energy Coop	12.9	13.3	13.8	14.9	15.1	15.3	15.2	15.0	15.1	15.1	2%
City of Norway	11.9	12.8	12.8	13.6	13.4	13.8	14.4	14.9	15.0	15.0	2%
City of South Haven	9.8	10.8	10.9	10.9	11.6	10.8	11.4	12.5	13.6	14.8	4%
City of Lansing	8.8	10.5	11.7	12.8	13.2	13.6	14.8	14.7	14.8	14.6	5%
Tri-County Electric Coop	12.2	12.3	12.6	13.5	13.8	14.0	13.9	13.9	14.4	14.6	2%
Wyandotte Municipal Serv Comm	9.3	9.3	12.8	14.2	14.9	14.6	14.5	14.6	14.7	14.3	4%
City of Sturgis	9.7	10.6	11.9	12.0	12.4	11.5	12.8	12.8	13.9	14.2	4%
City of Grand Haven	11.2	12.1	12.5	13.4	13.5	13.6	15.4	14.7	14.0	14.0	2%
Midwest Energy Cooperative	11.3	11.8	14.0	14.9	14.8	15.1	16.0	16.2	15.6	13.9	2%
Cherryland Electric Coop Inc	11.5	11.8	12.5	13.7	13.6	13.5	13.6	13.8	13.9	13.8	2%
Village of L'Anse	12.6	12.1	12.3	13.0	13.5	13.7	14.6	13.9	14.5	13.6	1%
Thumb Electric Coop of Mich	11.2	12.0	12.0	11.3	11.2	11.5	12.0	12.2	13.3	13.5	2%
City of Gladstone	13.0	13.4	14.8	14.9	12.5	13.3	12.1	11.7	13.0	13.4	0%
City of Marshall	13.0	13.2	12.4	12.8	13.8	14.6	13.6	13.0	13.2	13.2	0%
Village of Baraga	12.2	12.6	12.3	12.4	13.2	12.7	12.6	21.4	13.1	13.2	1%
City of Bay City	10.0	10.0	10.4	10.5	10.8	11.7	11.7	12.4	13.1	13.0	3%
Cloverland Electric Co-op	11.4	11.0	11.4	11.4	11.0	11.7	11.8	12.6	12.8	12.7	1%
City of Niles	9.6	9.6	9.8	10.5	10.1	10.6	11.4	11.6	11.7	12.2	2%
City of Escanaba	10.4	10.8	11.2	11.0	10.5	10.7	11.1	11.4	11.6	12.1	2%
Hillsdale Board of Public Wks	11.3	11.6	11.3	11.5	12.4	13.0	12.6	11.7	14.0	12.1	1%
City of Holland	9.4	9.8	9.9	10.3	10.6	11.0	11.1	11.7	12.4	12.0	2%
Coldwater Board of Public Util	12.4	12.0	11.7	12.1	12.3	12.7	11.6	11.7	12.4	11.5	-1%
City of Petoskey	8.7	9.1	9.7	10.4	11.1	11.2	12.0	11.5	11.3	11.3	3%
City of Traverse City	9.3	9.4	9.8	9.6	9.9	11.8	11.3	10.8	10.8	10.8	2%
City of Zeeland	7.5	8.2	8.5	8.7	8.9	9.4	9.1	8.6	8.6	8.6	1%

Figure 97: 2018 Michigan Utilities Commercial Electricity Price

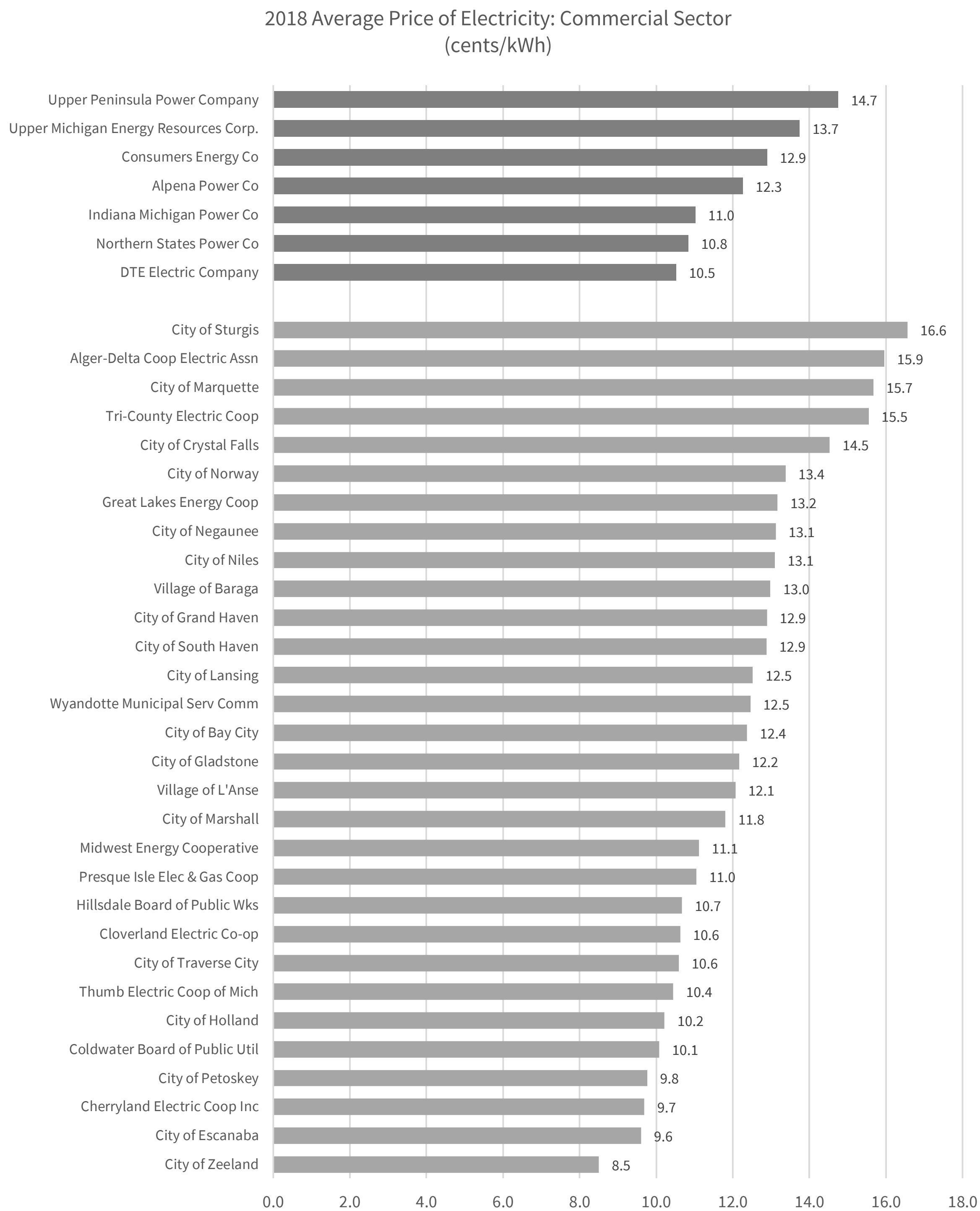


Figure 98: Michigan Utilities Commercial Electricity Price

Average Price of Electricity: Commercial Sector (cents/kWh)											
Utility	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR
Upper Peninsula Power Company	13.6	14.1	14.6	14.7	15.7	16.9	16.5	15.8	17.0	14.7	1%
Upper Michigan Energy Resources Corp.									14.2	13.7	
Consumers Energy Co	9.9	11.0	11.2	11.6	12.2	12.6	12.3	12.3	12.7	12.9	3%
Alpena Power Co	11.2	11.7	12.1	12.3	12.4	11.9	11.9	11.3	11.9	12.3	1%
Indiana Michigan Power Co	7.3	7.9	8.7	9.2	9.3	9.2	9.6	9.8	10.2	11.0	4%
Northern States Power Co	8.5	8.6	9.0	9.6	9.8	11.0	11.4	11.2	11.7	10.8	2%
DTE Electric Company	8.9	9.3	10.3	11.4	11.3	10.5	9.9	10.0	10.3	10.5	2%
City of Sturgis	11.9	13.4	14.5	14.1	14.7	14.4	15.3	15.4	16.1	16.6	3%
Alger-Delta Coop Electric Assn	15.1	16.2	15.3	15.6	15.6	14.8	15.8	15.4	15.6	15.9	1%
City of Marquette	7.7	8.2	8.3	9.0	9.5	10.1	10.8	12.6	15.6	15.7	7%
Tri-County Electric Coop	13.5	13.6	14.1	14.8	14.9	15.6	15.2	15.0	15.1	15.5	1%
City of Crystal Falls	10.1	12.2	13.2	12.8	12.6	13.5	13.5	13.6	13.8	14.5	4%
City of Norway	11.1	12.9	12.4	13.0	12.3	12.4	14.3	14.3	13.4	13.4	2%
Great Lakes Energy Coop	11.0	11.2	11.3	11.9	12.8	13.0	13.0	12.9	13.0	13.2	2%
City of Negaunee	15.0	12.5	11.7	11.8	11.6	12.2	13.2	13.3	13.4	13.1	-1%
City of Niles	9.9	9.8	9.8	10.3	10.7	10.7	11.7	12.2	12.0	13.1	3%
Village of Baraga	11.6	13.2	13.1	13.1	13.2	12.1	12.2	19.2	12.6	13.0	1%
City of Grand Haven	11.8	13.6	15.0	14.6	15.3	15.3	13.6	13.4	12.8	12.9	1%
City of South Haven	9.8	9.9	9.7	10.3	10.6	9.5	10.1	10.9	11.7	12.9	3%
City of Lansing	7.9	9.2	10.3	11.3	11.6	11.7	12.8	12.8	13.0	12.5	5%
Wyandotte Municipal Serv Comm	10.8	10.8	15.9	15.4	15.5	15.7	12.4	12.3	12.4	12.5	1%
City of Bay City	9.5	9.5	9.7	9.8	10.2	11.1	11.2	11.4	12.4	12.4	3%
City of Gladstone	11.6	11.7	11.8	10.2	12.3	13.7	10.5	10.2	11.4	12.2	0%
Village of L'Anse	11.4	11.1	11.3	12.3	12.8	12.7	13.2	12.2	13.0	12.1	1%
City of Marshall	14.1	14.1	12.4	11.9	11.8	13.3	11.9	11.3	11.8	11.8	-2%
Midwest Energy Cooperative	9.0	9.4	8.4	8.6	9.1	9.4	8.8	9.7	9.9	11.1	2%
Presque Isle Elec & Gas Coop	10.1	10.4	10.8	11.1	11.4	11.1	11.0	10.9	11.1	11.0	1%
Hillsdale Board of Public Wks	9.7	10.0	9.6	9.7	11.0	11.6	11.3	10.1	11.7	10.7	1%
Cloverland Electric Co-op	10.3	10.1	10.5	10.6	10.1	10.6	10.4	11.1	10.5	10.6	0%
City of Traverse City	9.2	9.2	9.8	10.0	10.2	11.9	11.2	10.6	10.7	10.6	1%
Thumb Electric Coop of Mich	10.3	11.0	10.9	9.8	9.7	9.5	8.4	8.4	10.6	10.4	0%
City of Holland	8.2	8.3	8.5	8.7	9.2	9.5	10.1	10.5	10.8	10.2	2%
Coldwater Board of Public Util	11.8	11.5	11.3	11.7	11.9	12.4	10.3	9.6	10.5	10.1	-2%
City of Petoskey	8.0	8.4	9.0	9.7	10.3	9.8	10.5	10.1	9.9	9.8	2%
Cherryland Electric Coop Inc	9.2	9.4	9.8	10.2	10.5	10.6	10.1	10.3	10.5	9.7	0%
City of Escanaba	9.5	10.0	10.4	9.6	8.9	9.0	9.2	9.6	9.4	9.6	0%
City of Zeeland	7.8	8.4	8.7	8.9	9.3	9.6	9.2	8.6	8.6	8.5	1%

Figure 99: 2018 Michigan Utilities Industrial Electricity Price

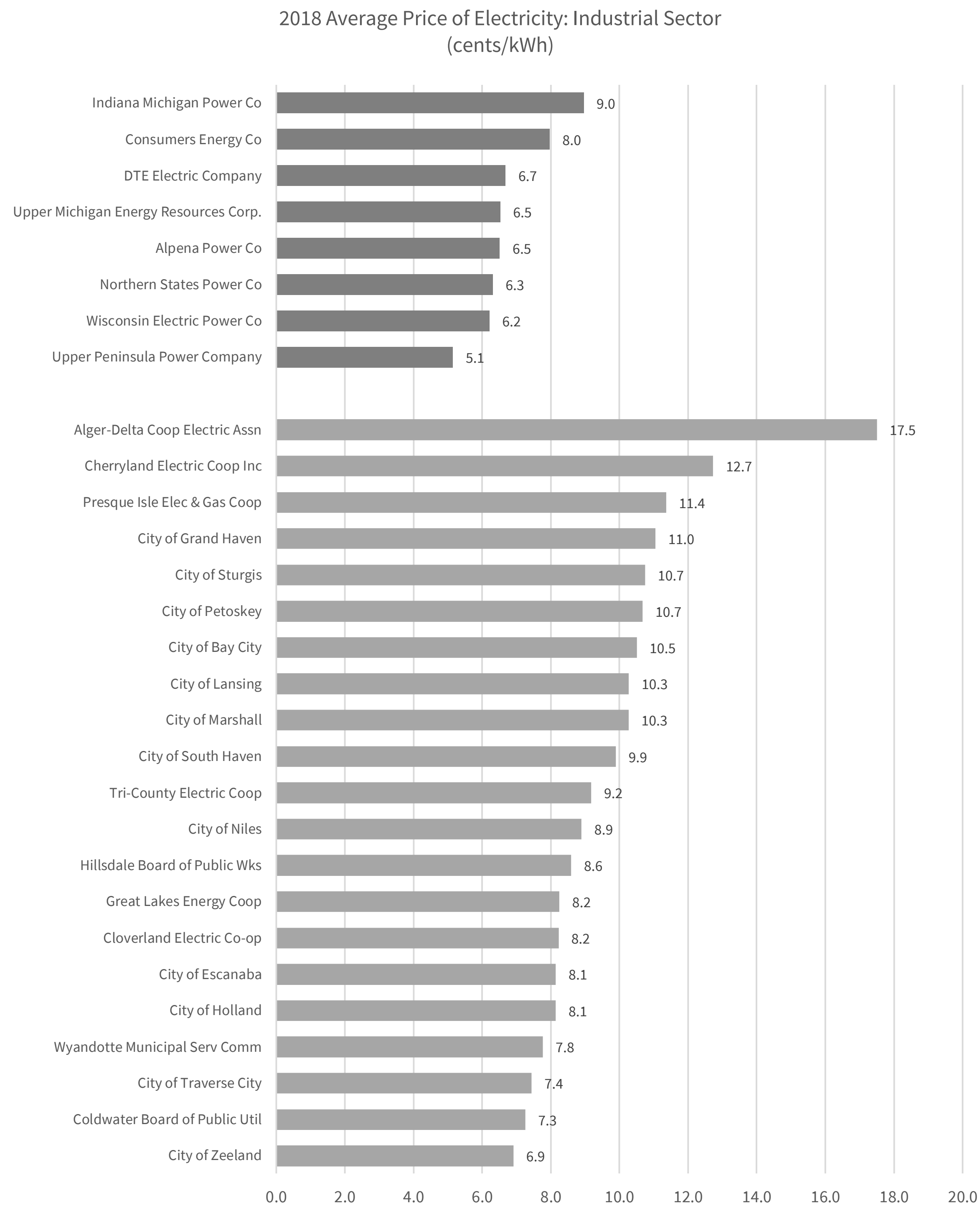


Figure 100: Michigan Utilities Industrial Electricity Price

Average Price of Electricity: Industrial Sector (cents/kWh)											
Utility	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Indiana Michigan Power Co	5.8	6.3	7.1	7.7	7.8	7.7	8.0	8.4	8.6	9.0	4%
Consumers Energy Co	7.6	8.2	8.1	8.3	9.0	8.8	8.0	7.7	8.2	8.0	0%
DTE Electric Company	6.9	6.4	7.1	7.8	7.8	7.5	6.7	6.5	6.7	6.7	0%
Upper Michigan Energy Resources Corp.									6.7	6.5	
Alpena Power Co	6.1	6.2	6.4	6.3	6.4	6.7	6.1	5.9	6.2	6.5	1%
Northern States Power Co	6.7	6.6	6.9	6.9	7.0	7.6	7.3	6.9	7.4	6.3	-1%
Wisconsin Electric Power Co	4.7	5.6	6.0	6.2	6.8	8.1	6.1	5.8	5.8	6.2	3%
Upper Peninsula Power Company	5.8	6.1	5.8	5.3	5.7	7.5	5.8	9.1	6.7	5.1	-1%
Alger-Delta Coop Electric Assn					13.7	14.3	13.6	13.3	13.2	17.5	
Cherryland Electric Coop Inc					13.1	13.4	13.0	12.9	13.7	12.7	
Presque Isle Elec & Gas Coop	10.1	10.4	10.7	11.7	12.0	11.6	11.4	11.2	11.5	11.4	1%
City of Grand Haven	9.0	9.1	9.2	9.4	9.6	9.6	11.3	11.2	10.9	11.0	2%
City of Sturgis	7.6	8.4	9.1	9.0	9.2	9.7	9.9	10.0	10.4	10.7	3%
City of Petoskey	8.8	10.2	10.2	11.1	11.6	11.2	11.5	11.4	11.5	10.7	2%
City of Bay City	7.3	7.1	8.1	8.7	9.1	9.8	9.5	10.0	10.8	10.5	4%
City of Lansing	6.8	7.5	8.4	9.5	9.7	9.8	10.6	10.4	10.6	10.3	4%
City of Marshall	9.7	9.7	9.9	9.0	9.9	11.8	10.4	10.1	10.3	10.3	1%
City of South Haven	7.8	7.8	7.1	7.5	7.8	6.7	7.3	8.0	8.9	9.9	2%
Tri-County Electric Coop	9.1	8.8	9.3	10.1	9.7	9.8	9.7	9.6	9.4	9.2	0%
City of Niles	7.5	7.5	7.5	7.6	8.0	7.9	7.7	8.3	8.6	8.9	2%
Hillsdale Board of Public Wks	8.4	8.6	8.7	8.7	9.8	10.1	9.7	8.3	9.2	8.6	0%
Great Lakes Energy Coop	6.9	7.0	7.3	7.7	8.4	8.6	8.4	8.2	8.2	8.2	2%
Cloverland Electric Co-op	7.7	7.3	7.9	7.8	7.2	7.9	8.1	8.3	8.2	8.2	1%
City of Escanaba	8.2	8.7	9.0	8.5	8.0	8.0	8.3	8.6	8.1	8.1	0%
City of Holland	7.1	7.2	7.4	7.5	7.6	8.0	8.2	8.6	8.8	8.1	1%
Wyandotte Municipal Serv Comm	7.3	6.8	10.0	10.6	9.7	9.9	9.4	9.4	8.5	7.8	1%
City of Traverse City	7.0	6.8	7.5	7.6	7.9	9.6	8.2	8.0	7.8	7.4	1%
Coldwater Board of Public Util	9.7	9.1	8.7	8.4	8.1	8.3	7.3	7.3	8.0	7.3	-3%
City of Zeeland	6.3	6.8	7.1	7.2	7.6	7.8	7.5	7.0	7.0	6.9	1%

Figure 101: 2018 Michigan Utilities All Sectors Electricity Price

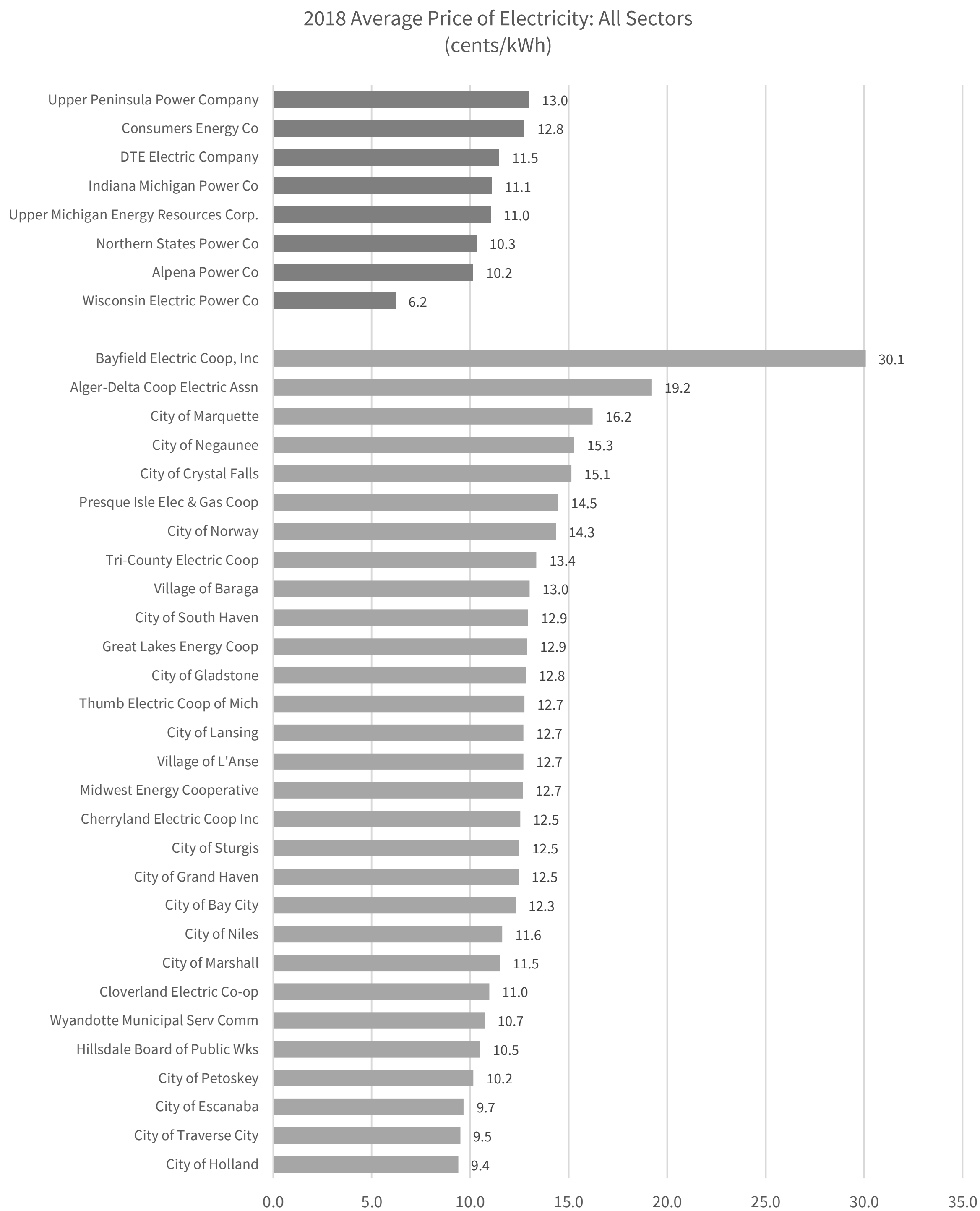


Figure 102: Michigan Utilities All Sectors Electricity Price

Average Price of Electricity: All Sectors (cents/kWh)											
Utility	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR
Upper Peninsula Power Company	11.3	12.3	12.7	12.5	13.1	15.2	14.1	16.0	14.8	13.0	1%
Consumers Energy Co	9.9	11.0	11.2	11.5	12.2	12.3	12.1	12.3	12.7	12.8	3%
DTE Electric Company	9.5	9.8	10.9	11.9	11.9	11.2	10.8	11.3	11.3	11.5	2%
Indiana Michigan Power Co	6.7	7.3	8.2	9.0	9.2	9.1	9.6	9.9	10.2	11.1	5%
Upper Michigan Energy Resources Corp.									11.3	11.0	
Northern States Power Co	8.5	8.6	9.0	9.5	9.7	10.7	10.9	10.7	11.2	10.3	2%
Alpena Power Co	9.5	10.0	10.3	10.1	10.2	9.9	9.8	9.4	9.7	10.2	1%
Wisconsin Electric Power Co	5.7	6.5	6.9	7.3	8.4	13.8	7.3	7.0	5.8	6.2	1%
Bayfield Electric Coop, Inc	20.0	23.0	25.0	28.3	28.7	28.6	30.7	29.4	29.4	30.1	4%
Alger-Delta Coop Electric Assn	17.7	19.3	19.1	19.7	18.7	18.6	18.6	18.3	17.8	19.2	1%
City of Marquette	8.1	8.5	8.7	9.4	9.8	10.5	11.2	13.0	16.1	16.2	7%
City of Negaunee	15.1	15.0	15.0	13.8	13.8	14.2	15.2	15.5	15.6	15.3	0%
City of Crystal Falls	10.9	13.5	14.0	14.0	13.9	14.3	14.6	14.5	14.8	15.1	3%
Presque Isle Elec & Gas Coop	12.2	12.7	13.4	14.3	15.0	14.6	14.5	14.4	14.7	14.5	2%
City of Norway	11.3	12.4	12.2	12.9	12.9	13.3	14.4	14.7	14.3	14.3	2%
Tri-County Electric Coop	11.7	11.7	12.0	12.9	13.0	13.2	13.0	13.0	13.3	13.4	1%
Village of Baraga	11.7	13.1	13.0	13.0	13.2	12.2	12.2	19.6	12.7	13.0	1%
City of South Haven	9.5	9.9	9.7	10.1	10.5	9.5	10.0	10.9	11.8	12.9	3%
Great Lakes Energy Coop	11.2	11.5	11.9	12.6	12.8	13.1	12.9	12.7	12.8	12.9	1%
City of Gladstone	12.1	12.3	13.4	12.7	12.4	13.5	11.4	11.0	12.3	12.8	1%
Thumb Electric Coop of Mich	11.1	11.8	11.8	11.0	10.9	11.1	11.2	11.3	12.7	12.7	1%
City of Lansing	7.9	9.2	10.3	11.4	11.7	11.9	12.9	12.8	13.1	12.7	5%
Village of L'Anse	11.9	11.5	11.7	12.6	13.1	13.1	13.8	12.9	13.6	12.7	1%
Midwest Energy Cooperative	10.3	10.7	11.2	11.6	12.0	12.3	12.4	12.8	12.6	12.7	2%
Cherryland Electric Coop Inc	10.8	11.1	11.7	12.6	12.6	12.6	12.5	12.7	12.9	12.5	2%
City of Sturgis	8.8	9.8	10.7	10.5	10.8	10.9	11.4	11.5	12.1	12.5	4%
City of Grand Haven	10.6	11.5	12.1	12.2	12.5	12.4	13.1	12.8	12.3	12.5	2%
City of Bay City	9.3	9.4	9.7	9.9	10.3	11.1	11.1	11.6	12.4	12.3	3%
City of Niles	9.1	9.1	9.2	9.6	9.7	9.8	10.4	10.9	11.0	11.6	2%
City of Marshall	11.8	11.8	11.3	11.0	11.5	12.9	11.7	11.2	11.5	11.5	0%
Cloverland Electric Co-op	10.7	9.6	10.2	10.2	9.7	10.4	10.7	11.3	10.8	11.0	0%
Wyandotte Municipal Serv Comm	8.2	7.8	11.2	11.9	11.5	11.6	11.5	11.6	11.1	10.7	3%
Hillsdale Board of Public Wks	9.8	10.1	10.0	10.0	11.2	11.6	11.3	10.1	11.6	10.5	1%
City of Petoskey	8.2	8.6	9.2	9.9	10.5	10.2	10.9	10.5	10.3	10.2	2%
City of Escanaba	9.2	9.7	10.0	9.5	8.9	9.0	9.3	9.6	9.4	9.7	0%
City of Traverse City	8.4	8.4	9.0	9.1	9.3	11.0	10.1	9.7	9.6	9.5	1%
City of Holland	7.9	8.1	8.2	8.4	8.6	8.9	9.3	9.7	9.9	9.4	2%
Coldwater Board of Public Util	10.4	9.9	9.6	9.3	9.0	9.3	8.2	8.1	8.8	8.0	-3%
City of Zeeland	6.7	7.2	7.5	7.7	8.0	8.3	7.9	7.4	7.5	7.4	1%

NATURAL GAS

Figure 103: 2018 Residential Natural Gas Price

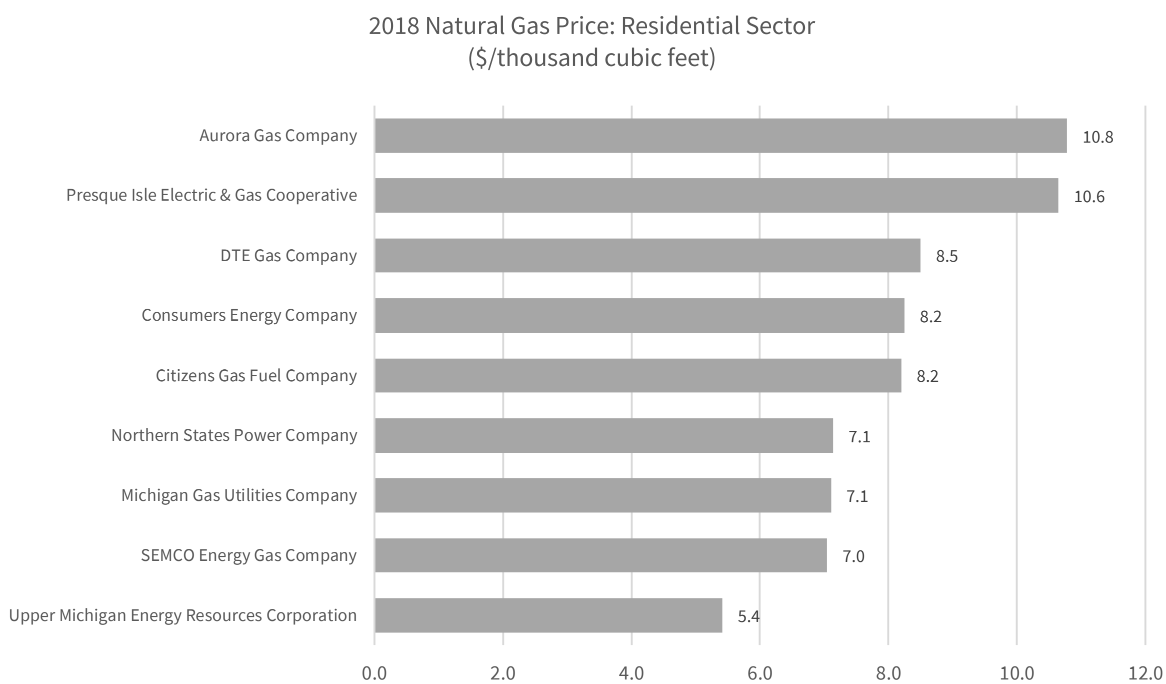


Figure 104: Michigan Utilities Residential Gas Price

Natural Gas Price: Residential Sector ($/thousand cubic feet)											
Utility	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**CAGR**
Aurora Gas Company	14.7	13.5	12.5	11.6	11.3	10.8	10.3	11.9	9.7	10.8	-3%
Presque Isle Electric & Gas Cooperative	14.4	14.2	13.1	13.0	12.2	11.5	11.8	11.7	10.8	10.6	-3%
DTE Gas Company	10.9	11.6	10.3	9.9	9.1	9.2	9.0	8.8	8.9	8.5	-2%
Consumers Energy Company	11.7	11.6	10.9	10.4	9.4	9.5	8.9	8.1	8.3	8.2	-3%
Citizens Gas Fuel Company	11.7	9.8	9.6	10.0	9.9	9.5	9.9	7.7	8.0	8.2	-3%
Northern States Power Company	10.2	7.8	7.1	6.6	6.8	7.9	8.3	6.8	7.3	7.1	-4%
Michigan Gas Utilities Company	10.4	10.3	9.9	7.9	7.6	8.2	7.3	7.0	7.7	7.1	-4%
SEMCO Energy Gas Company	10.3	8.8	8.5	8.1	7.7	9.0	7.7	7.2	7.4	7.0	-4%
Upper Michigan Energy Resources Corporation	9.4	7.7	7.3	6.4	6.7	7.4	7.7	5.7	6.1	5.4	-5%

Figure 105: 2018 Michigan Utilities Natural Gas Losses

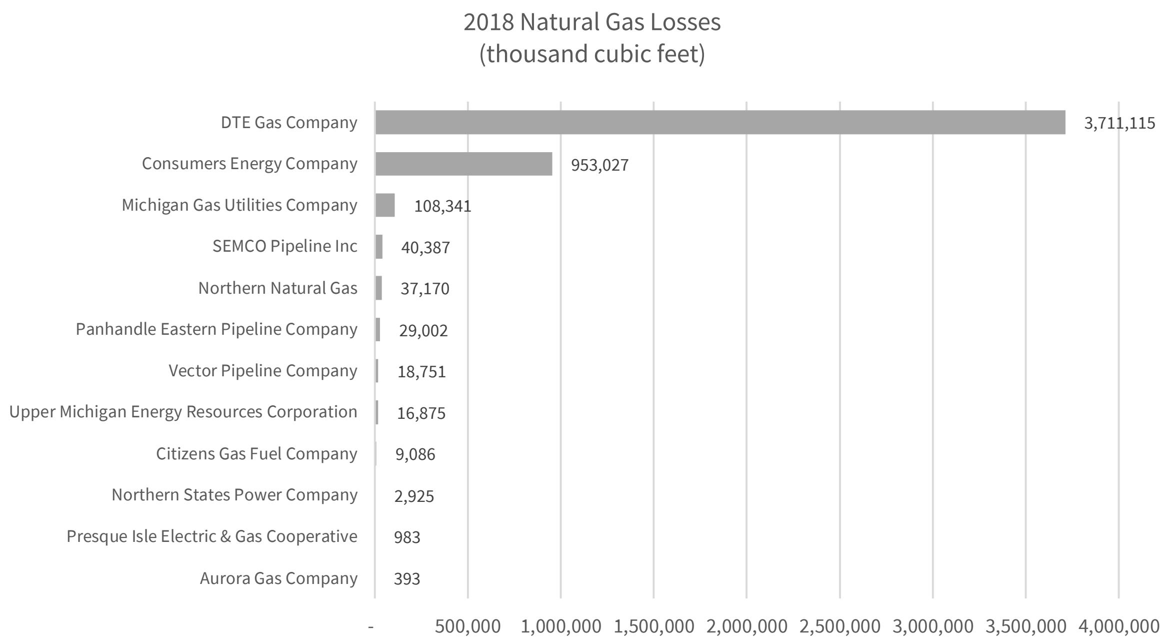


Figure 106: Michigan Utilities Natural Gas Losses

Natural Gas Losses (thousand cubic feet)										
Utility	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
DTE Gas Company	3,800,000	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
Consumers Energy Company		780,568	842,416	812,797	863,854	913,618	875,184	884,583	870,501	953,027
Michigan Gas Utilities Company		98,014	107,084	65,824	130,116	142,509	96,181	103,547	97,065	108,341
SEMCO Pipeline Inc		30,799	27,839	25,611	26,053	20,304	13,032	26,667	29,822	40,387
Northern Natural Gas		29,195	28,990	35,128	39,047	43,928	46,690	42,299	37,655	37,170
Panhandle Eastern Pipeline Company		49,584	51,681	35,319	56,177	46,500	27,822	33,256	30,814	29,002
Vector Pipeline Company			27,342	16,191	86,782	15,877	25,077	17,449	80,798	18,751
Upper Michigan Energy Resources Corporation			1,321	3,939	7,239	15,936	14,290	15,211	15,217	16,875
Citizens Gas Fuel Company		8,947	23,802	2,334	12,049	13,456	8,668	8,586	8,462	9,086
Northern States Power Company		2,715	3,082	1,959	3,955	4,076	2,542	2,914	2,723	2,925
Presque Isle Electric & Gas Cooperative		2,006	2,356	578	719	848	746	688	737	983
Aurora Gas Company		759	877	518	1,008	1,177	873	848	786	393

Figure 107: 2018 Michigan Utilities Unaccounted-for Gas

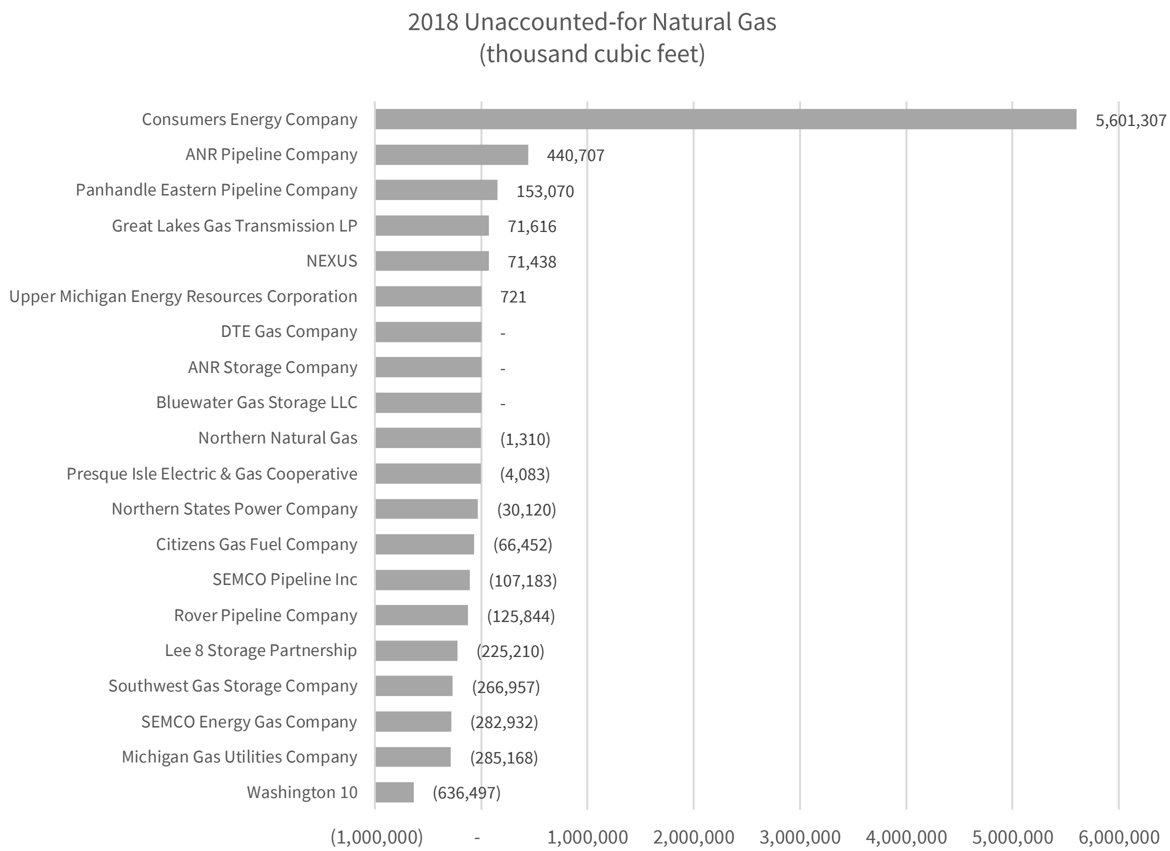
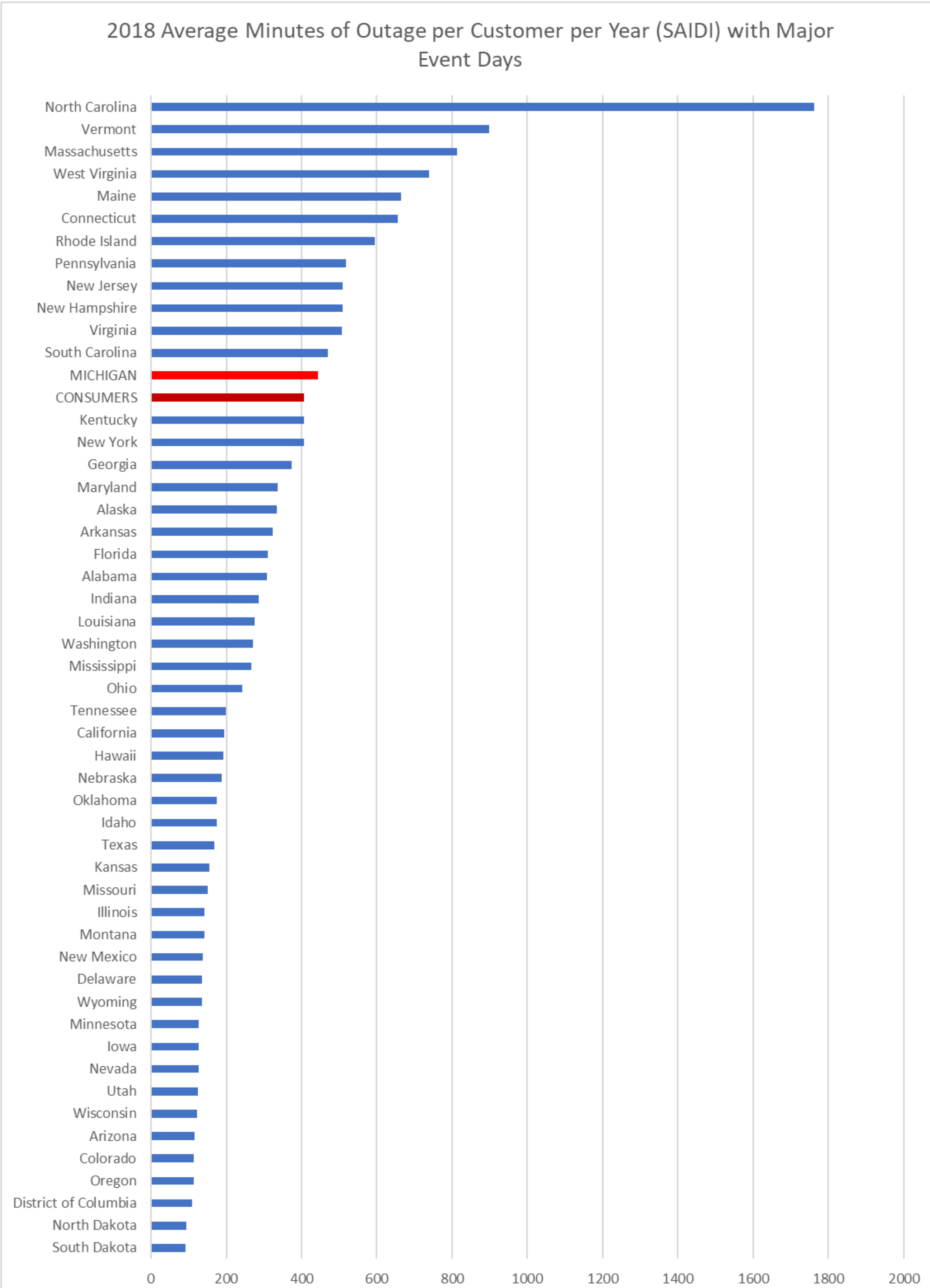
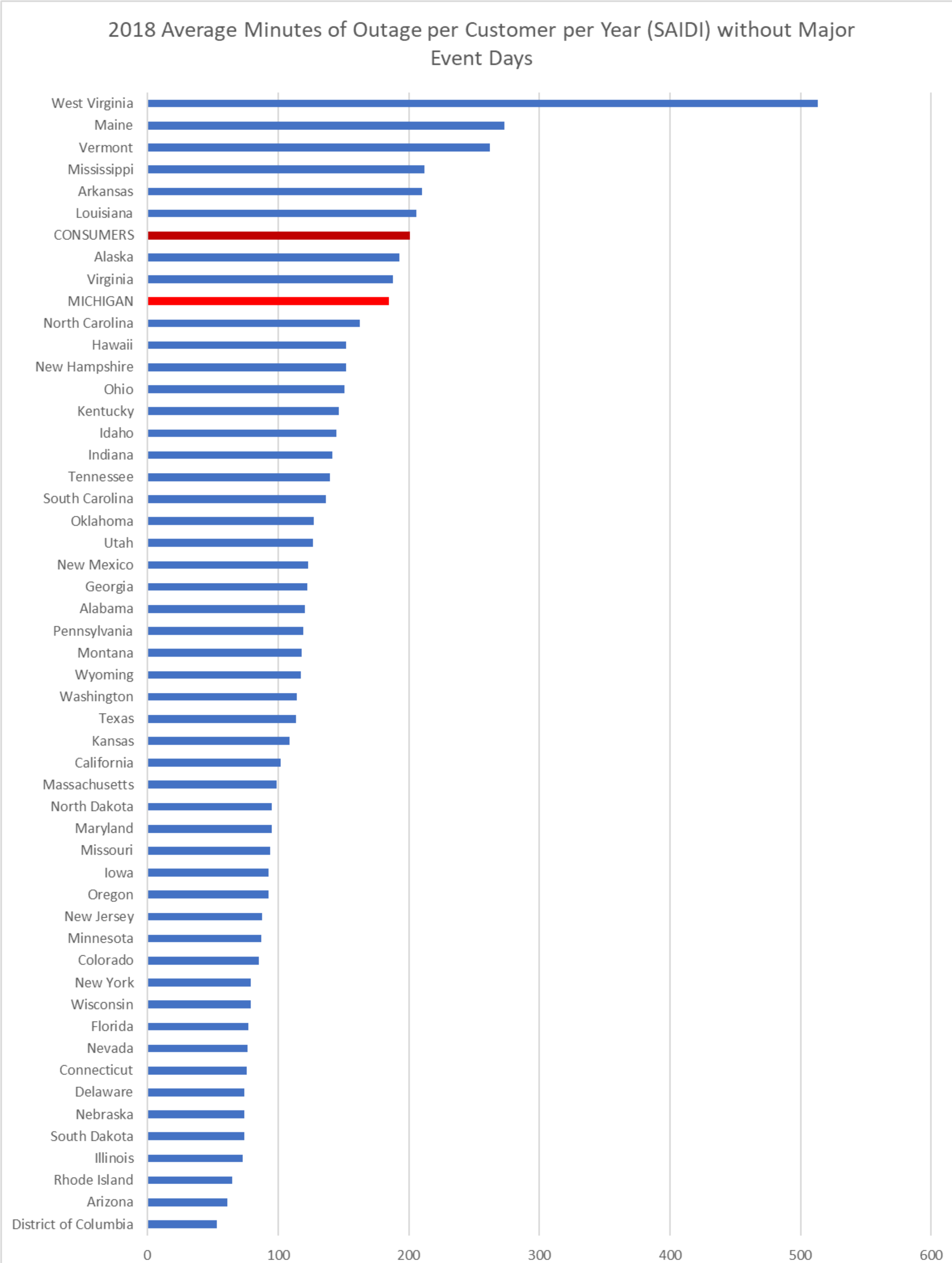


Figure 108: Michigan Utilities Unaccounted-for Gas

Unaccounted-for Natural Gas (thousand cubic feet)										
Utility	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Consumers Energy Company	928,210	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
ANR Pipeline Company	128,698	196,348	(207,121)	101,255	285,091	283,110	336,607	280,126	514,147	440,707
Panhandle Eastern Pipeline Company	53,663	(58,481)	(39,619)	729	(123,187)	(276,287)	(291,035)	(72,461)	188,892	153,070
Great Lakes Gas Transmission LP	1,104,605	(617,355)	470,948	582,697	814,314	254,289	1,173,536	1,145,507	228,391	71,616
NEXUS										71,438
Upper Michigan Energy Resources Corporation	9,556	4,412	14,122	25,299	24,486	23,695	(15,577)	(19,892)	11,362	721
DTE Gas Company	8,229,772	8,180,371	9,550,191	4,019,087	4,019,123	5,048,994	3,687,637	(8,656)	737	-
ANR Storage Company						-		-	-	-
Bluewater Gas Storage LLC	-	-	-			-		-	-	-
Northern Natural Gas	(3,503)	(4,430)	12,618	14,243	14,720	7,486	(7,226)	5,251	11,894	(1,310)
Presque Isle Electric & Gas Cooperative	(224)	24,946	13,988	(2,547)	30,385	47,917	10,551	19,574	19,015	(4,083)
Northern States Power Company	(202,368)	(1,442)	(12,809)	(23,833)	(791)	22,690	5,154	28,564	14,275	(30,120)
Citizens Gas Fuel Company	(15,803)	2,010	(63,963)	6,539	1,820	(174,140)	(11,828)	105,426	(11,215)	(66,452)
SEMCO Pipeline Inc	(76,049)	(40,311)	(251,581)	(64,734)	(120,755)	(116,887)	(54,746)	(71,679)	(52,726)	(107,183)
Rover Pipeline Company									-	(125,844)
Lee 8 Storage Partnership	(480,170)	227,562	(52,618)	(40,139)	(58,875)	(41,083)	(59,065)	(44,269)	(41,400)	(225,210)
Southwest Gas Storage Company	301,683	1,488,393	(390,776)	(270,981)	(373,011)	(518,469)	(388,323)	(267,286)	(301,035)	(266,957)
SEMCO Energy Gas Company	208,053	(90,634)	376,460	(10,990)	87,152	59,652	(119,755)	330,056	(81,614)	(282,932)
Michigan Gas Utilities Company	(176,235)	(646,777)	778,430	(341,119)	23,437	(448,673)	(296,444)	(117,986)	(182,430)	(285,168)
Washington 10			-	(989,642)	(621,230)	(847,318)	(830,653)	(489,958)	(575,464)	(636,497)


2018 Average Minutes of Outage per Customer per Year (SAIDI) with Major Event Days
North Carolina
Vermont
Massachusetts
West Virginia
Maine
Connecticut
Rhode Island
Pennsylvania
New Jersey
New Hampshire
Virginia
South Carolina
MICHIGAN
CONSUMERS
Kentucky
New York
Georgia
Maryland
Alaska
Arkansas
Florida
Alabama
Indiana
Louisiana
Washington
Mississippi
Ohio
Tennessee
California
Hawaii
Nebraska
Oklahoma
Idaho
Texas
Kansas
Missouri
Illinois
Montana
New Mexico
Delaware
Wyoming
Minnesota
Iowa
Nevada
Utah
Wisconsin
Arizona
Colorado
Oregon
District of Columbia
North Dakota
South Dakota
0
200
400
600
800
1000
1200
1400
1600
1800
2000


2018 Average Minutes of Outage per Customer per Year (SAIDI) without Major Event Days
West Virginia
Maine
Vermont
Mississippi
Arkansas
Louisiana
CONSUMERS
Alaska
Virginia
MICHIGAN
North Carolina
Hawaii
New Hampshire
Ohio
Kentucky
Idaho
Indiana
Tennessee
South Carolina
Oklahoma
Utah
New Mexico
Georgia
Alabama
Pennsylvania
Montana
Wyoming
Washington
Texas
Kansas
California
Massachusetts
North Dakota
Maryland
Missouri
Iowa
Oregon
New Jersey
Minnesota
Colorado
New York
Wisconsin
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Connecticut
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South Dakota
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Arizona
District of Columbia
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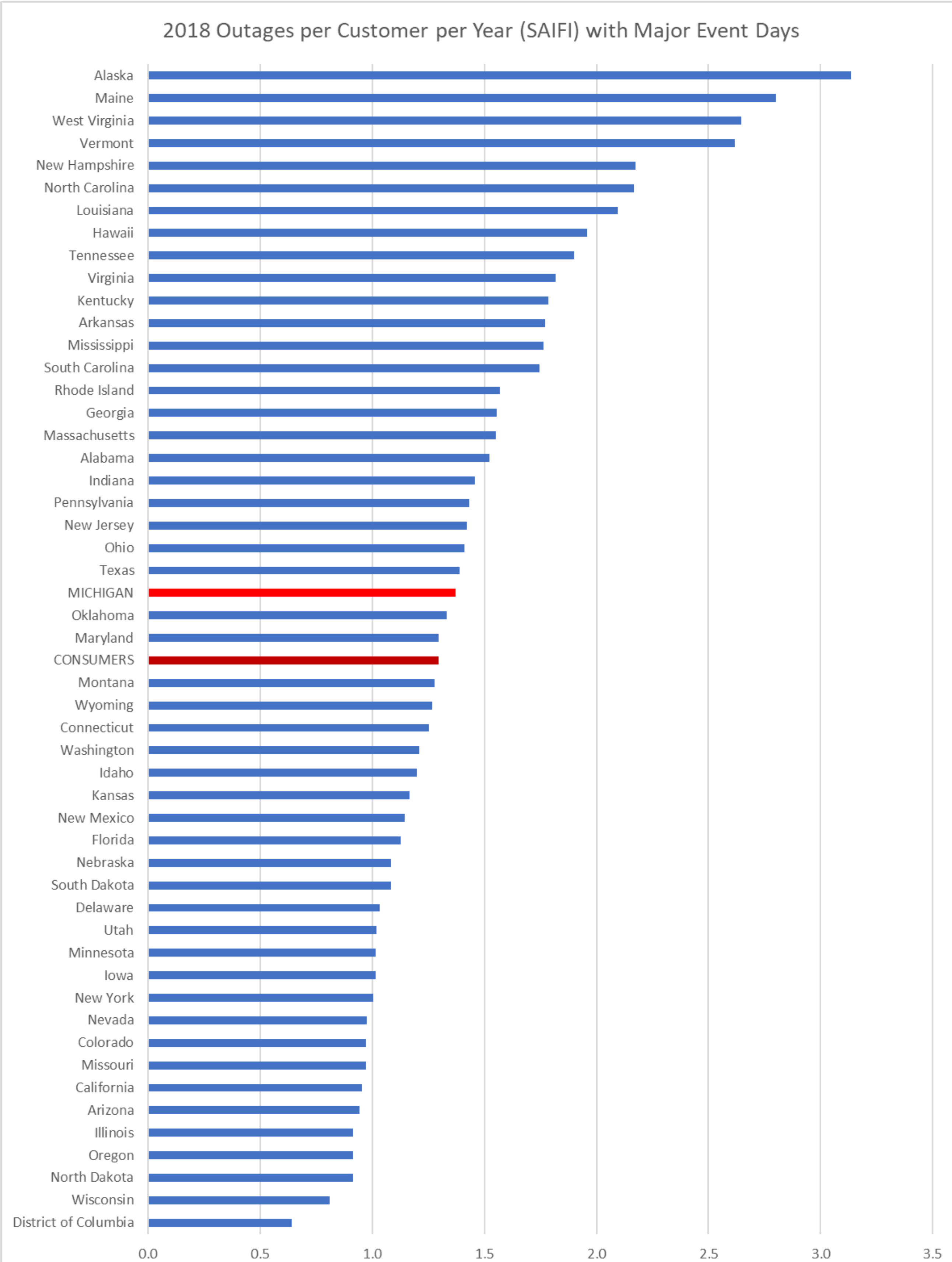
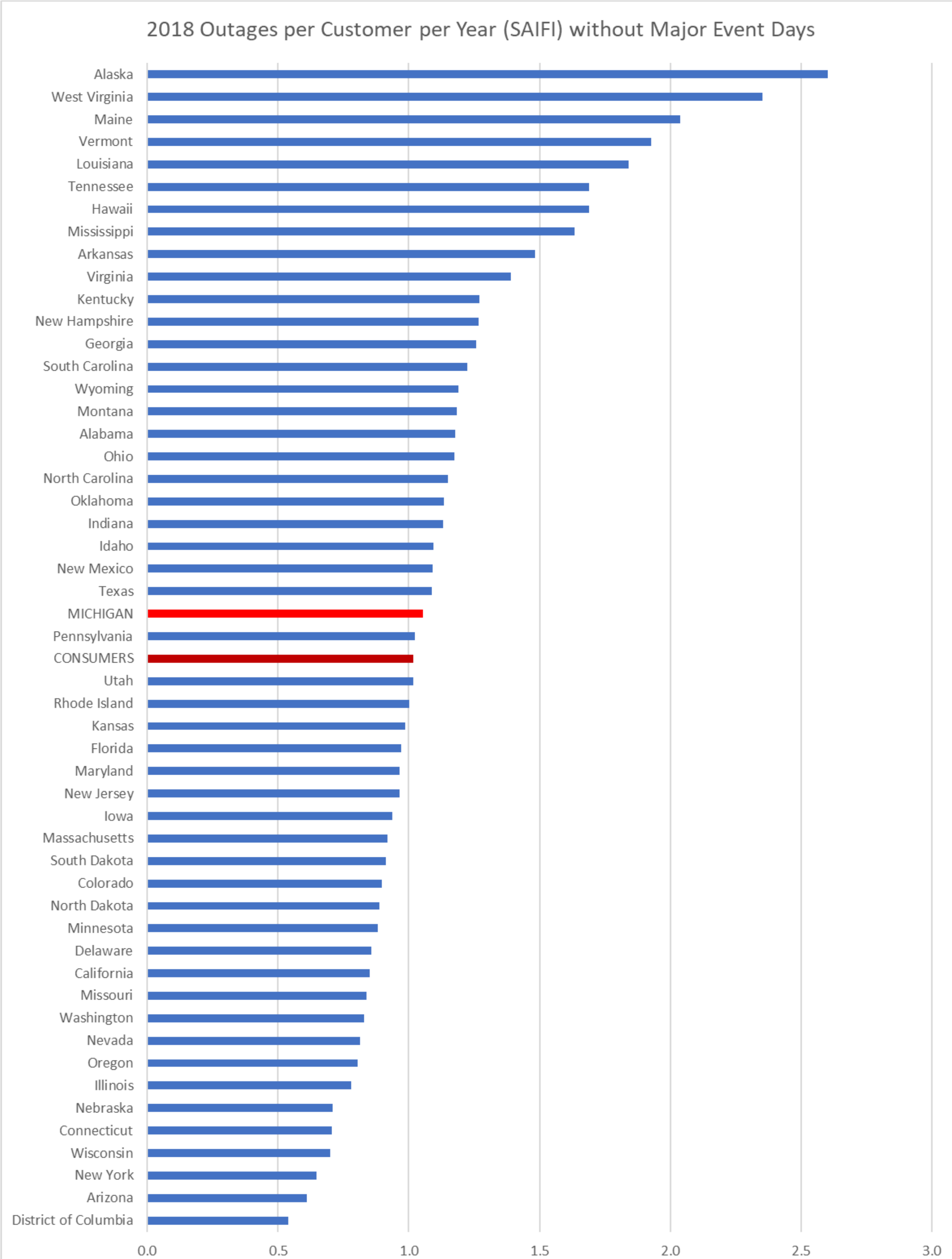
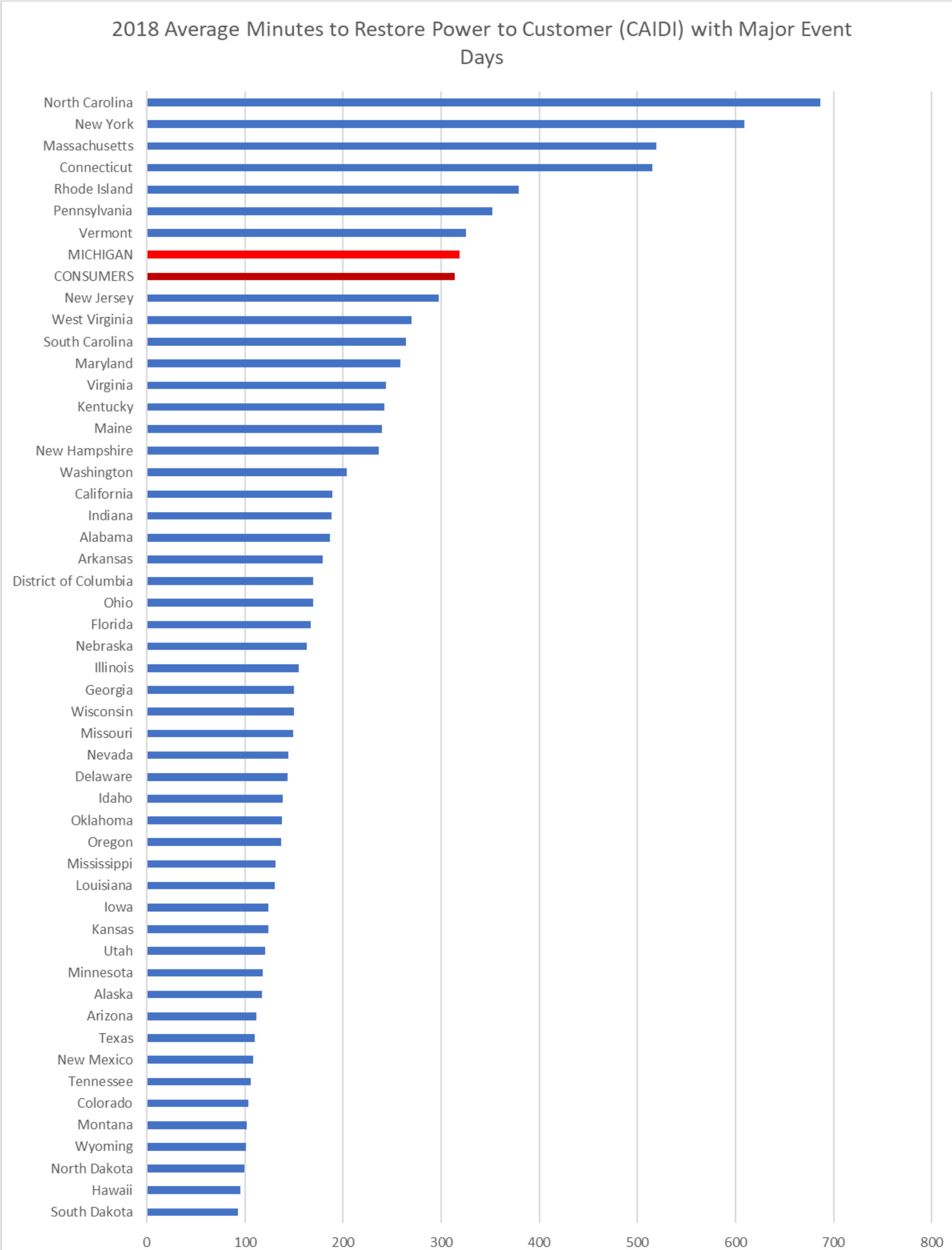
200
300
400
500
600


2018 Outages per Customer per Year (SAIFI) with Major Event Days
Alaska
Maine
West Virginia
Vermont
New Hampshire
North Carolina
Louisiana
Hawaii
Tennessee
Virginia
Kentucky
Arkansas
Mississippi
South Carolina
Rhode Island
Georgia
Massachusetts
Alabama
Indiana
Pennsylvania
New Jersey
Ohio
Texas
MICHIGAN
Oklahoma
Maryland
CONSUMERS
Montana
Wyoming
Connecticut
Washington
Idaho
Kansas
New Mexico
Florida
Nebraska
South Dakota
Delaware
Utah
Minnesota
Iowa
New York
Nevada
Colorado
Missouri
California
Arizona
Illinois
Oregon
North Dakota
Wisconsin
District of Columbia
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5


2018 Outages per Customer per Year (SAIFI) without Major Event Days
Alaska
West Virginia
Maine
Vermont
Louisiana
Tennessee
Hawaii
Mississippi
Arkansas
Virginia
Kentucky
New Hampshire
Georgia
South Carolina
Wyoming
Montana
Alabama
Ohio
North Carolina
Oklahoma
Indiana
Idaho
New Mexico
Texas
MICHIGAN
Pennsylvania
CONSUMERS
Utah
Rhode Island
Kansas
Florida
Maryland
New Jersey
Iowa
Massachusetts
South Dakota
Colorado
North Dakota
Minnesota
Delaware
California
Missouri
Washington
Nevada
Oregon
Illinois
Nebraska
Connecticut
Wisconsin
New York
Arizona
District of Columbia
0.0
0.5
1.0
1.5
2.0
2.5
3.0


2018 Average Minutes to Restore Power to Customer (CAIDI) with Major Event Days
North Carolina
New York
Massachusetts
Connecticut
Rhode Island
Pennsylvania
Vermont
MICHIGAN
CONSUMERS
New Jersey
West Virginia
South Carolina
Maryland
Virginia
Kentucky
Maine
New Hampshire
Washington
California
Indiana
Alabama
Arkansas
District of Columbia
Ohio
Florida
Nebraska
Illinois
Georgia
Wisconsin
Missouri
Nevada
Delaware
Idaho
Oklahoma
Oregon
Mississippi
Louisiana
Iowa
Kansas
Utah
Minnesota
Alaska
Arizona
Texas
New Mexico
Tennessee
Colorado
Montana
Wyoming
North Dakota
Hawaii
South Dakota
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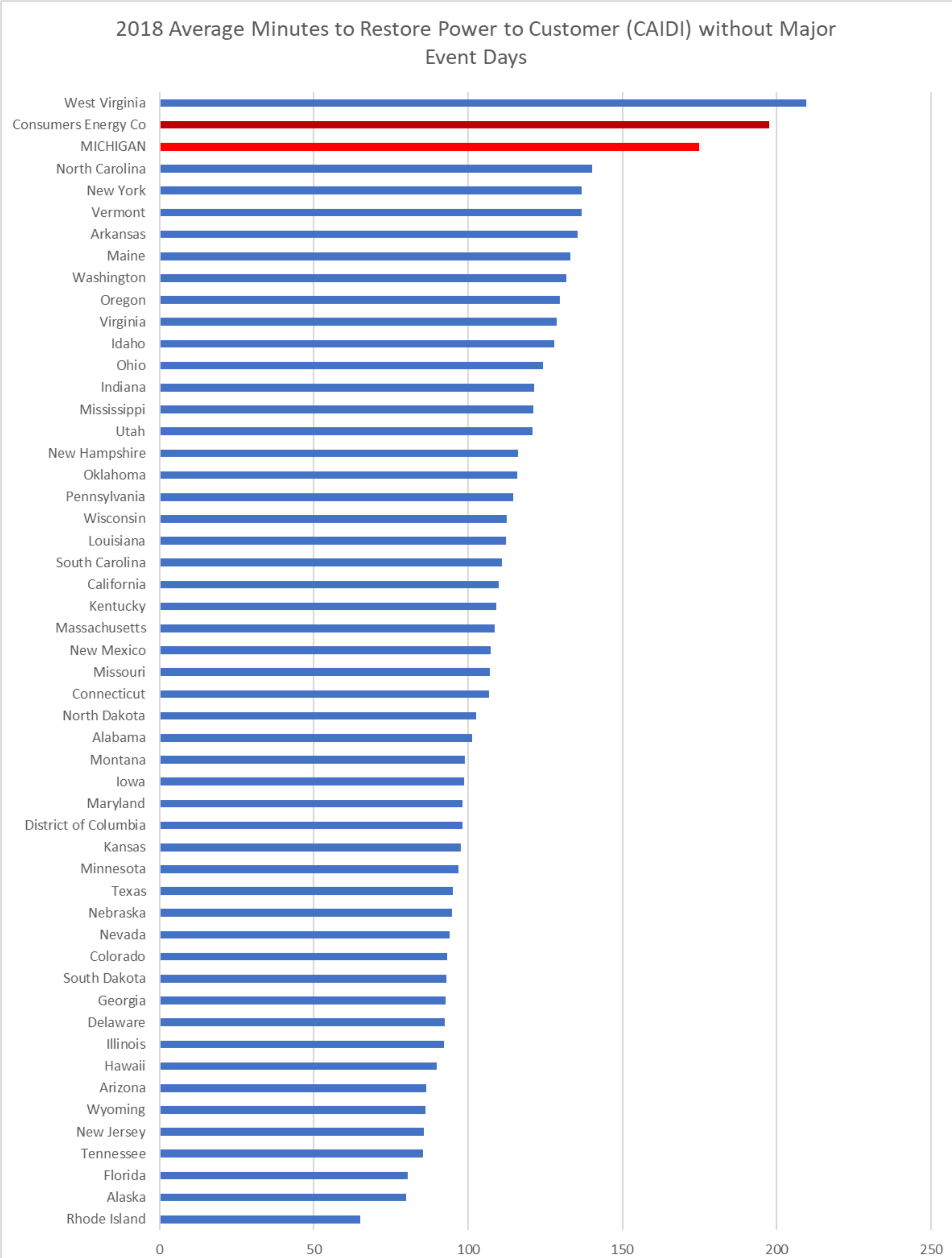
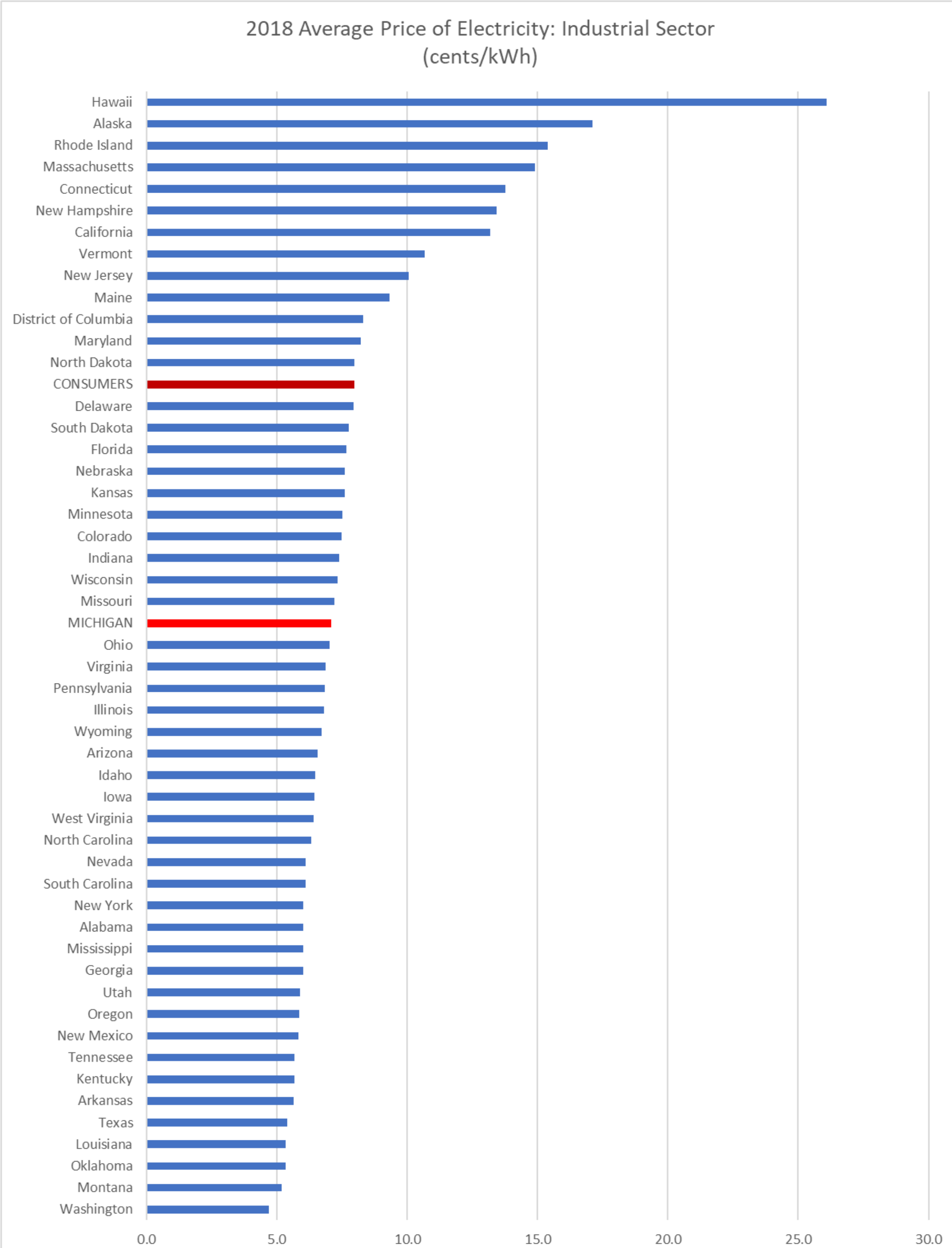
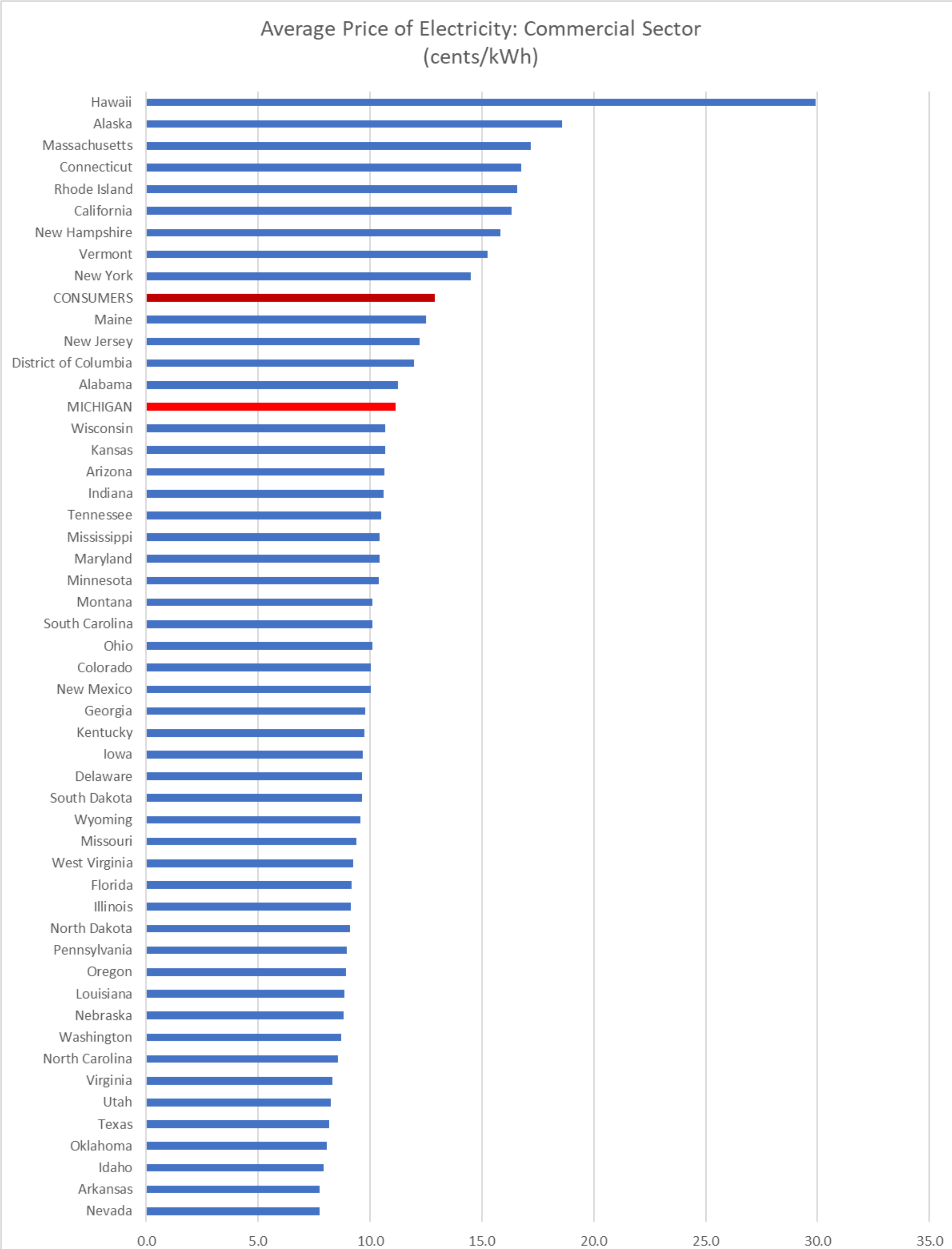
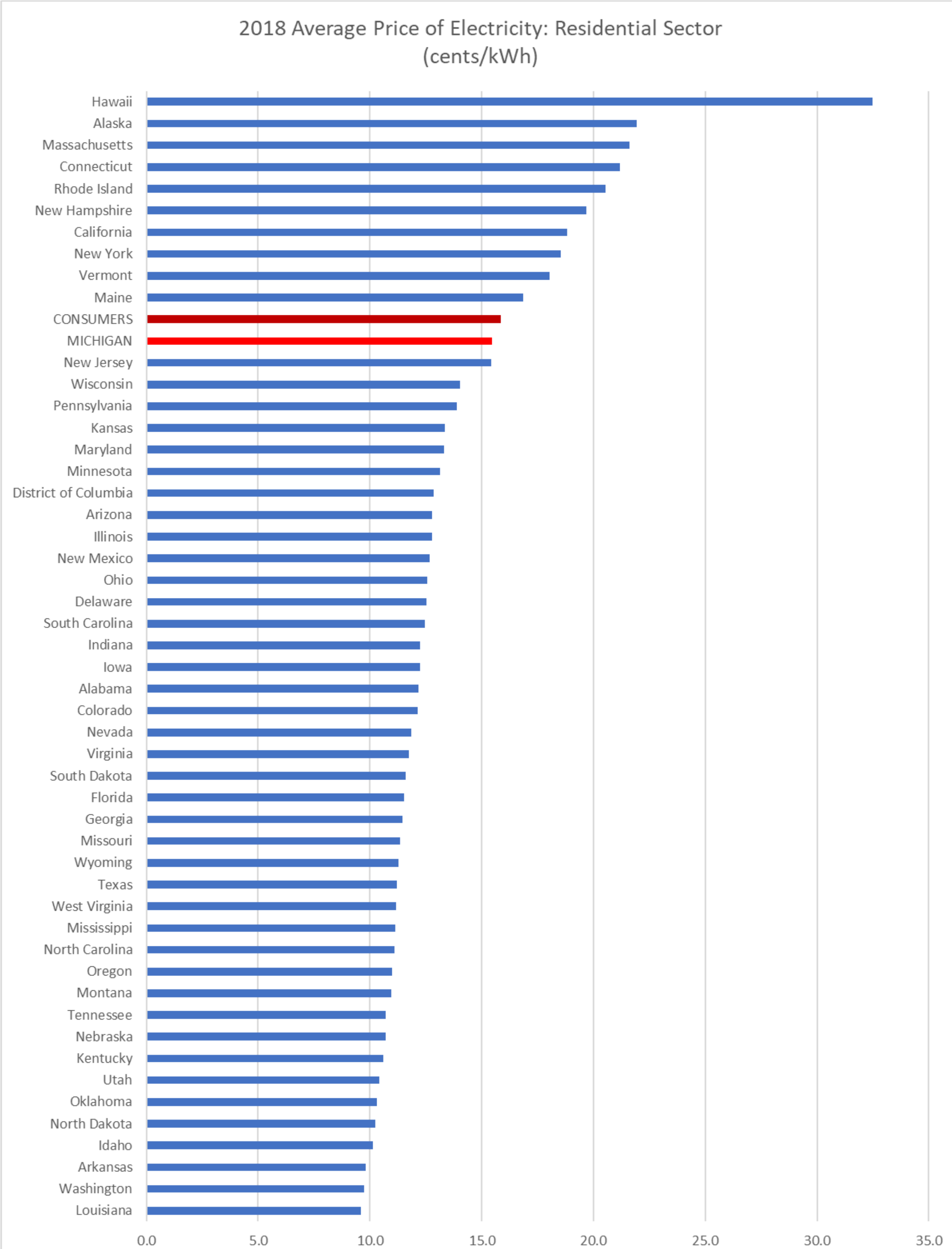
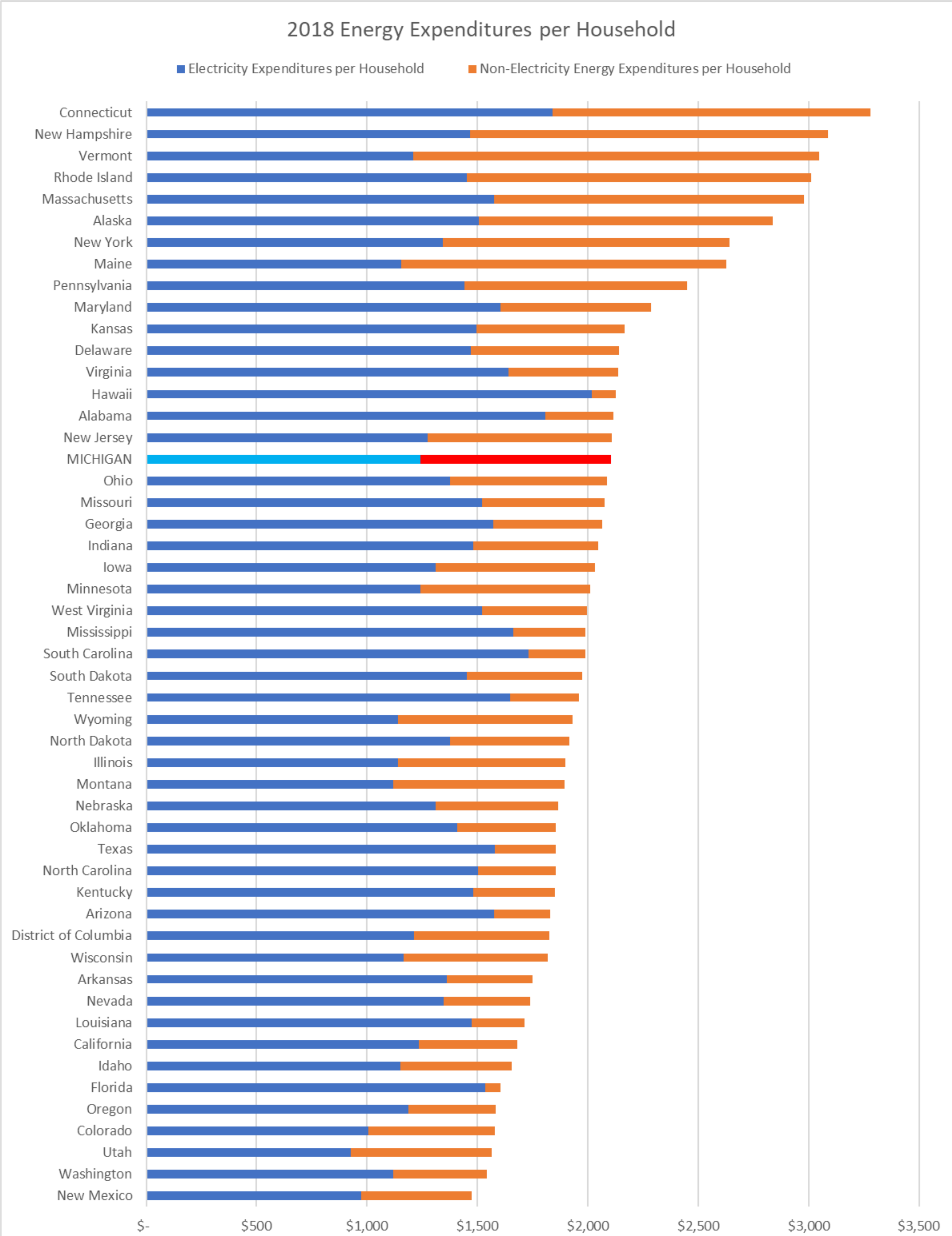
100
200
300
400
500
600
700
800

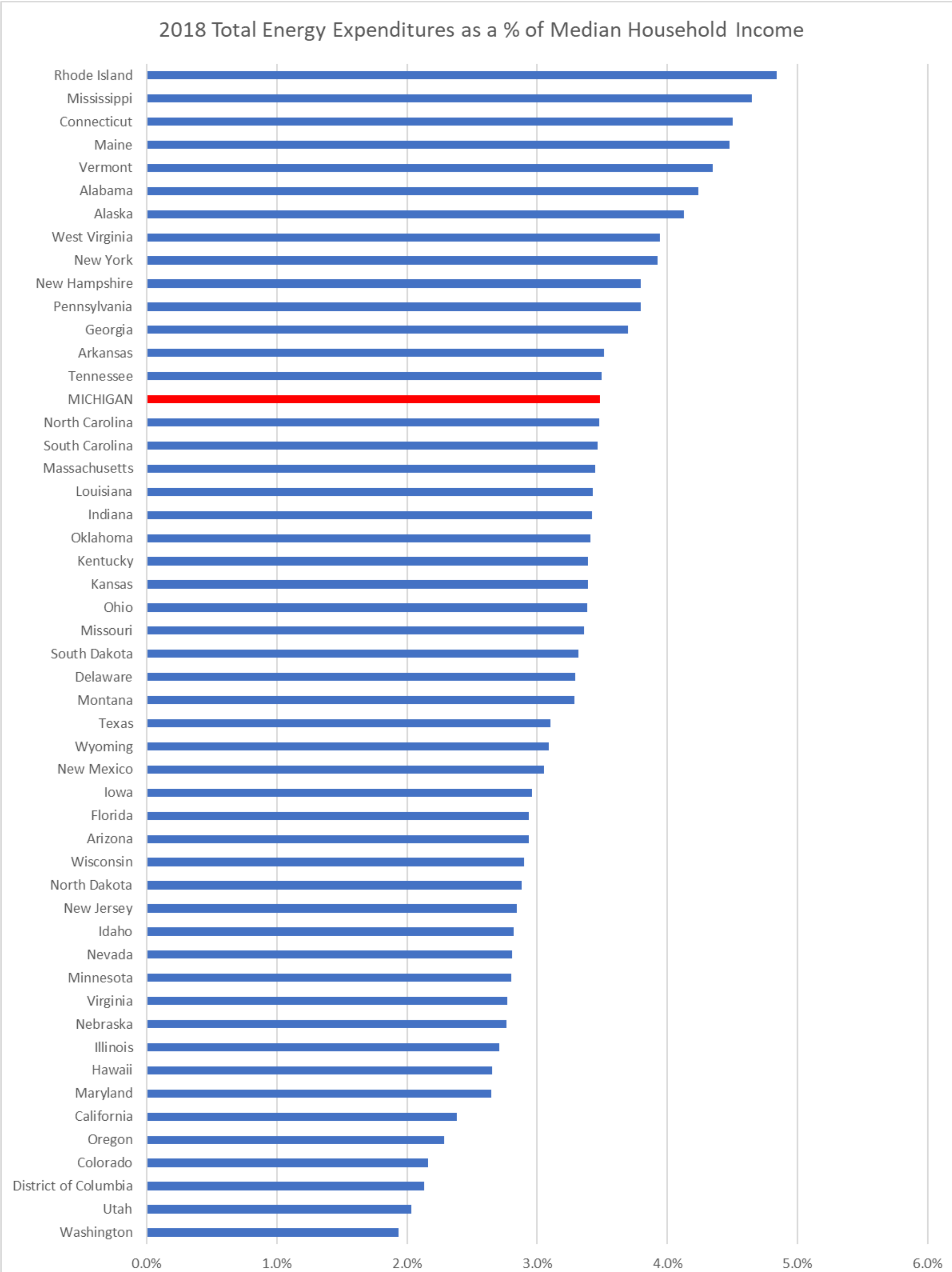

2018 Average Minutes to Restore Power to Customer (CAIDI) without Major Event Days
West Virginia
Consumers Energy Co
MICHIGAN
North Carolina
New York
Vermont
Arkansas
Maine
Washington
Oregon
Virginia
Idaho
Ohio
Indiana
Mississippi
Utah
New Hampshire
Oklahoma
Pennsylvania
Wisconsin
Louisiana
South Carolina
California
Kentucky
Massachusetts
New Mexico
Missouri
Connecticut
North Dakota
Alabama
Montana
Iowa
Maryland
District of Columbia
Kansas
Minnesota
Texas
Nebraska
Nevada
Colorado
South Dakota
Georgia
Delaware
Illinois
Hawaii
Arizona
Wyoming
New Jersey
Tennessee
Florida
Alaska
Rhode Island
0
50
100
150
200
250

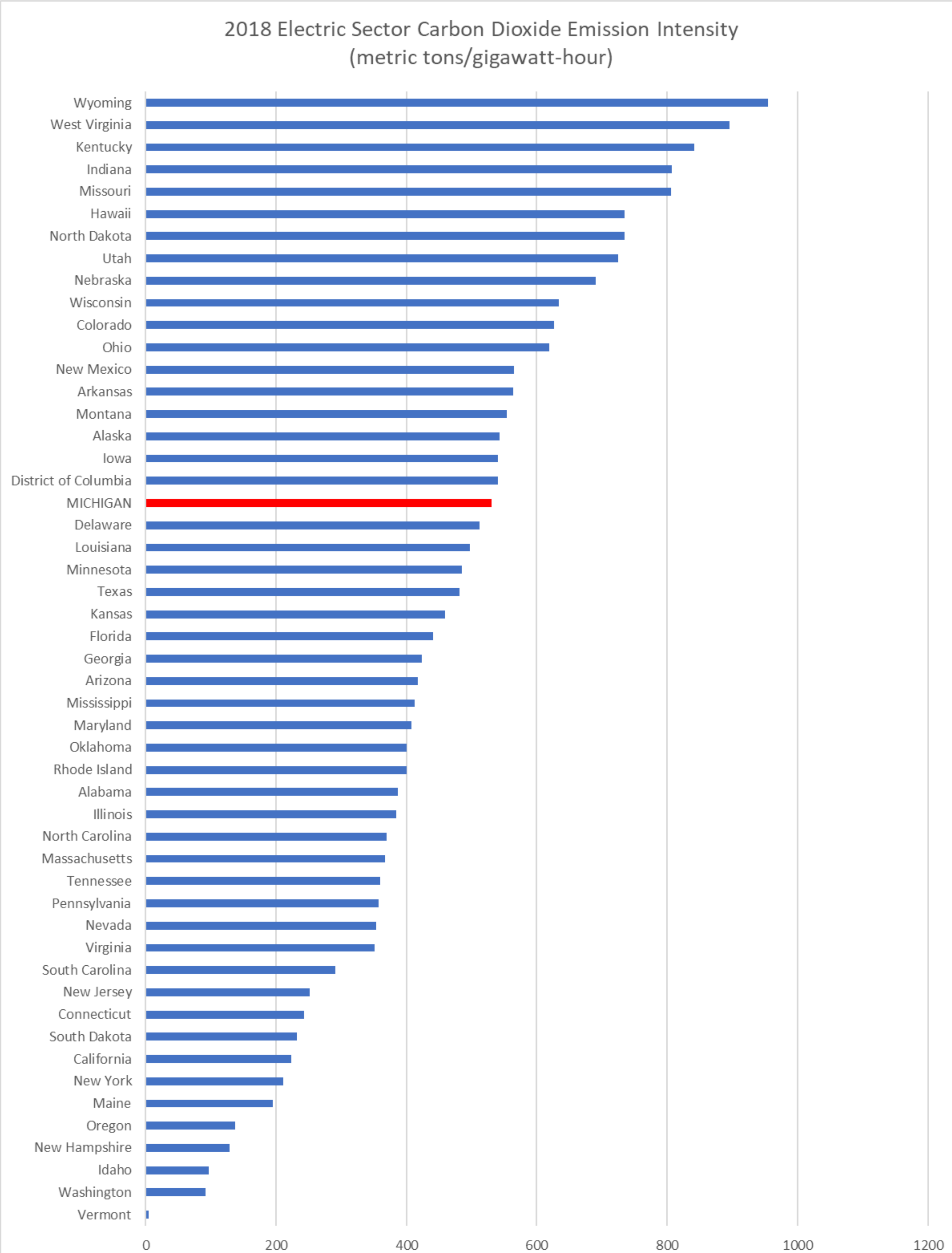

2018 Average Price of Electricity: Industrial Sector
(cents/kWh)
Hawaii
Alaska
Rhode Island
Massachusetts
Connecticut
New Hampshire
California
Vermont
New Jersey
Maine
District of Columbia
Maryland
North Dakota
CONSUMERS
Delaware
South Dakota
Florida
Nebraska
Kansas
Minnesota
Colorado
Indiana
Wisconsin
Missouri
MICHIGAN
Ohio
Virginia
Pennsylvania
Illinois
Wyoming
Arizona
Idaho
Iowa
West Virginia
North Carolina
Nevada
South Carolina
New York
Alabama
Mississippi
Georgia
Utah
Oregon
New Mexico
Tennessee
Kentucky
Arkansas
Texas
Louisiana
Oklahoma
Montana
Washington
0.0
5.0
10.0
15.0
20.0
25.0
30.0

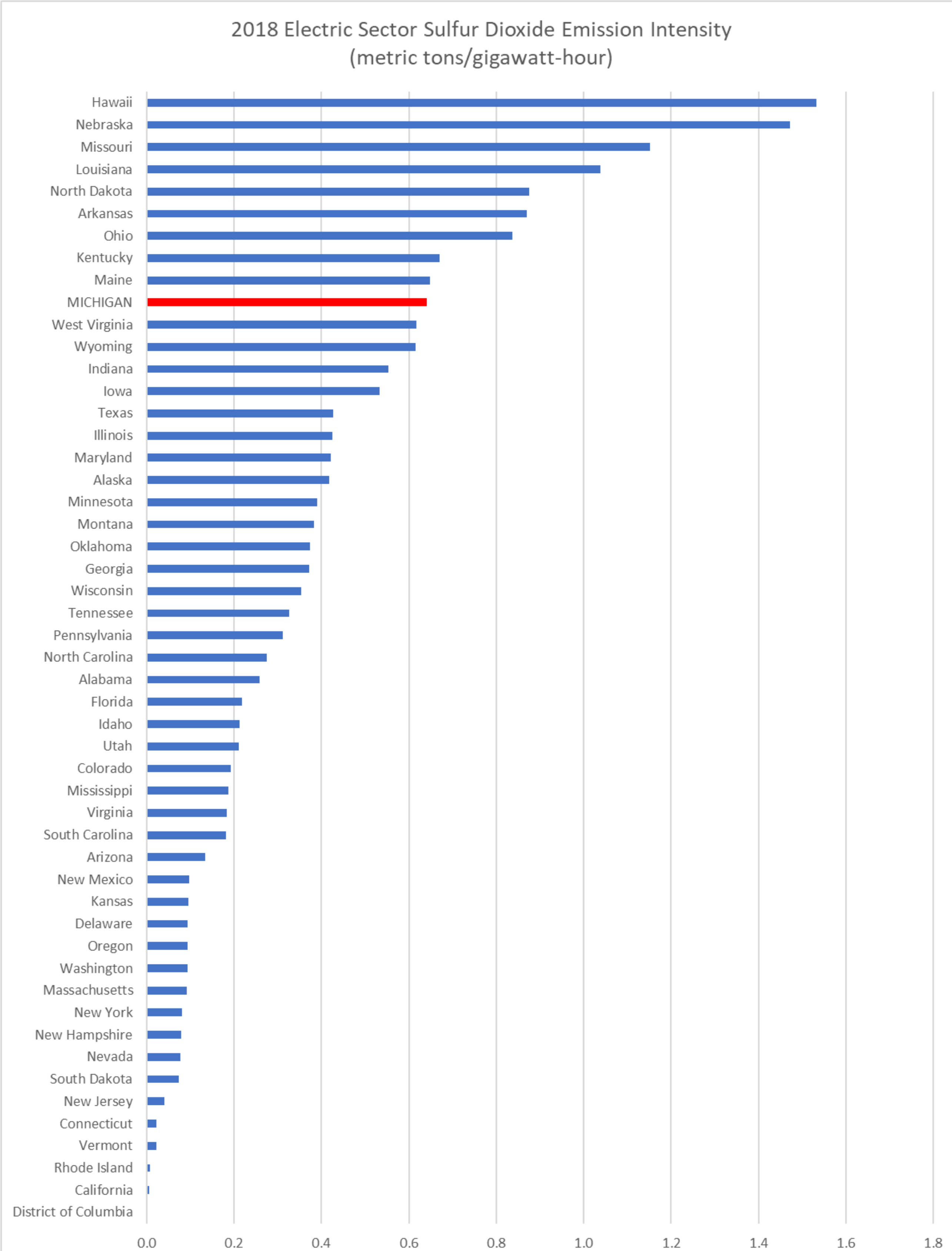

Average Price of Electricity: Commercial Sector
(cents/kWh)
Hawaii
Alaska
Massachusetts
Connecticut
Rhode Island
California
New Hampshire
Vermont
New York
CONSUMERS
Maine
New Jersey
District of Columbia
Alabama
MICHIGAN
Wisconsin
Kansas
Arizona
Indiana
Tennessee
Mississippi
Maryland
Minnesota
Montana
South Carolina
Ohio
Colorado
New Mexico
Georgia
Kentucky
Iowa
Delaware
South Dakota
Wyoming
Missouri
West Virginia
Florida
Illinois
North Dakota
Pennsylvania
Oregon
Louisiana
Nebraska
Washington
North Carolina
Virginia
Utah
Texas
Oklahoma
Idaho
Arkansas
Nevada
0.0
5.0
10.0
15.0
20.0
25.0
30.0
35.0

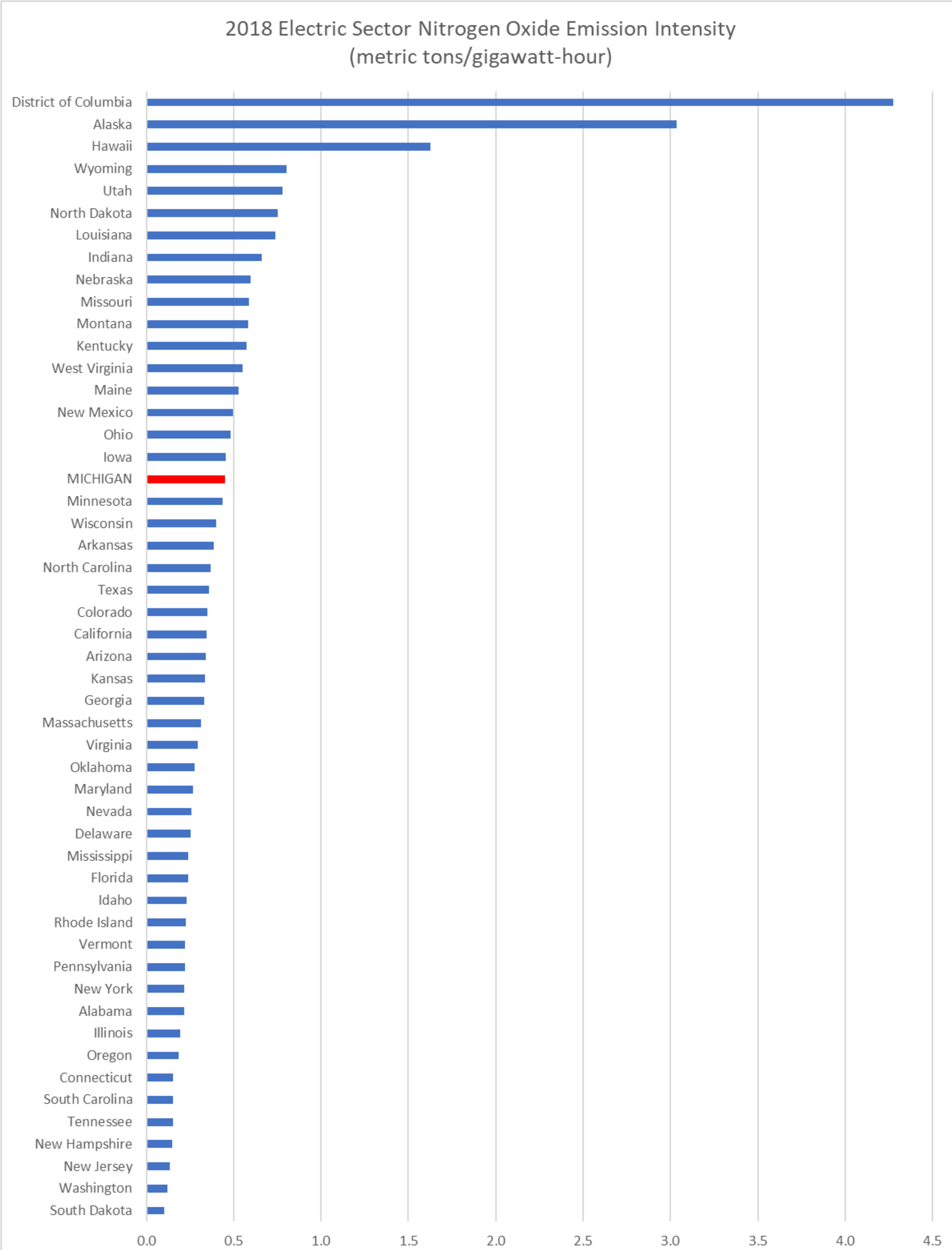

2018 Average Price of Electricity: Residential Sector
(cents/kWh)
Hawaii
Alaska
Massachusetts
Connecticut
Rhode Island
New Hampshire
California
New York
Vermont
Maine
CONSUMERS
MICHIGAN
New Jersey
Wisconsin
Pennsylvania
Kansas
Maryland
Minnesota
District of Columbia
Arizona
Illinois
New Mexico
Ohio
Delaware
South Carolina
Indiana
Iowa
Alabama
Colorado
Nevada
Virginia
South Dakota
Florida
Georgia
Missouri
Wyoming
Texas
West Virginia
Mississippi
North Carolina
Oregon
Montana
Tennessee
Nebraska
Kentucky
Utah
Oklahoma
North Dakota
Idaho
Arkansas
Washington
Louisiana
0.0
5.0
10.0
15.0
20.0
25.0
30.0
35.0


2018 Energy Expenditures per Household
Electricity Expenditures per Household
Non-Electricity Energy Expenditures per Household
Connecticut
New Hampshire
Vermont
Rhode Island
Massachusetts
Alaska
New York
Maine
Pennsylvania
Maryland
Kansas
Delaware
Virginia
Hawaii
Alabama
New Jersey
MICHIGAN
Ohio
Missouri
Georgia
Indiana
Iowa
Minnesota
West Virginia
Mississippi
South Carolina
South Dakota
Tennessee
Wyoming
North Dakota
Illinois
Montana
Nebraska
Oklahoma
Texas
North Carolina
Kentucky
Arizona
District of Columbia
Wisconsin
Arkansas
Nevada
Louisiana
California
Idaho
Florida
Oregon
Colorado
Utah
Washington
New Mexico
$-
$500
$1,000
$1,500
$2,000
$2,500
$3,000
$3,500


2018 Total Energy Expenditures as a % of Median Household Income
Rhode Island
Mississippi
Connecticut
Maine
Vermont
Alabama
Alaska
West Virginia
New York
New Hampshire
Pennsylvania
Georgia
Arkansas
Tennessee
MICHIGAN
North Carolina
South Carolina
Massachusetts
Louisiana
Indiana
Oklahoma
Kentucky
Kansas
Ohio
Missouri
South Dakota
Delaware
Montana
Texas
Wyoming
New Mexico
Iowa
Florida
Arizona
Wisconsin
North Dakota
New Jersey
Idaho
Nevada
Minnesota
Virginia
Nebraska
Illinois
Hawaii
Maryland
California
Oregon
Colorado
District of Columbia
Utah
Washington
0.0%
1.0%
2.0%
3.0%
4.0%
5.0%
6.0%


2018 Electric Sector Carbon Dioxide Emission Intensity
(metric tons/gigawatt-hour)
Wyoming
West Virginia
Kentucky
Indiana
Missouri
Hawaii
North Dakota
Utah
Nebraska
Wisconsin
Colorado
Ohio
New Mexico
Arkansas
Montana
Alaska
Iowa
District of Columbia
MICHIGAN
Delaware
Louisiana
Minnesota
Texas
Kansas
Florida
Georgia
Arizona
Mississippi
Maryland
Oklahoma
Rhode Island
Alabama
Illinois
North Carolina
Massachusetts
Tennessee
Pennsylvania
Nevada
Virginia
South Carolina
New Jersey
Connecticut
South Dakota
California
New York
Maine
Oregon
New Hampshire
Idaho
Washington
Vermont
0
200
400
600
800
1000
1200


2018 Electric Sector Sulfur Dioxide Emission Intensity
(metric tons/gigawatt-hour)
Hawaii
Nebraska
Missouri
Louisiana
North Dakota
Arkansas
Ohio
Kentucky
Maine
MICHIGAN
West Virginia
Wyoming
Indiana
Iowa
Texas
Illinois
Maryland
Alaska
Minnesota
Montana
Oklahoma
Georgia
Wisconsin
Tennessee
Pennsylvania
North Carolina
Alabama
Florida
Idaho
Utah
Colorado
Mississippi
Virginia
South Carolina
Arizona
New Mexico
Kansas
Delaware
Oregon
Washington
Massachusetts
New York
New Hampshire
Nevada
South Dakota
New Jersey
Connecticut
Vermont
Rhode Island
California
District of Columbia
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8


2018 Electric Sector Nitrogen Oxide Emission Intensity
(metric tons/gigawatt-hour)
District of Columbia
Alaska
Hawaii
Wyoming
Utah
North Dakota
Louisiana
Indiana
Nebraska
Missouri
Montana
Kentucky
West Virginia
Maine
New Mexico
Ohio
Iowa
MICHIGAN
Minnesota
Wisconsin
Arkansas
North Carolina
Texas
Colorado
California
Arizona
Kansas
Georgia
Massachusetts
Virginia
Oklahoma
Maryland
Nevada
Delaware
Mississippi
Florida
Idaho
Rhode Island
Vermont
Pennsylvania
New York
Alabama
Illinois
Oregon
Connecticut
South Carolina
Tennessee
New Hampshire
New Jersey
Washington
South Dakota
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5

Question:

28. Refer to page 37, line 5 through page 39, line 24, the section titled "Labor Rates".

a. Increases in average compensation of a work force will reflect average increases in the compensation of individual workers who continue working from one time period to another and the turnover of the workforce in which typically more senior and highly compensated employees depart and are replaced by less experienced workers who are also less compensated. Consequently, the rate of increase in average compensation of the workforce is less than the increases experienced by individual employees. Please explain whether the assumed labor rate of 3.2% is the average increase for the workforce or is the average increase experienced by individual continuing employees.
b. Provide documentation of the meaning of "Merit Increases" for each of the salary surveys provided in Confidential Exhibits A-72 through A-75.
c. If 3.2% increase is the projected average increase for the workforce, what is the average increase projected for individual continuing employees?
d. If the 3.2% increase is the projected increase for individual continuing employees, what is the average increase projected for the workforce?

Response:

a. The assumed rate of labor used to project O&M labor expense is 3.2%. The assumed rate is not an average increase in salary for the workforce or the average increase for individual continuing employees. The increase of 3.2% is consistent with the companied planned merit budget. It does not include other salary increases such as promotions or wage adjustments. The labor rate is derived from independent third-party survey sources. Merit rewards are for the achievement of goals and objectives, accomplishment of tasks, duties and responsibilities established annually for each individual employee. See Part III question 73 for a description of the type of salary increases that adjust base salaries (regular pay) for union and non-union employees.

b. The definition of merit for the salary surveys are as follows:
Conrad_Confidential_Exhibit_A72 - PayFactor : See definition in illustration below.

SURVEY METHODOLOGY AND DEFINITIONS

Payfactors clients and contacts were invited to participate in our Salary Budget Survey in mid-May of 2019 via email. Submissions were accepted through the end of June, resulting in 673 useable submissions.

Respondents were asked to submit data for US, Canada, and selected international locations for four employee groups:

- Non-exempt/Hourly Employees
- Exempt/Salaried (Non-management) Employees
- Exempt/Salaried Managers
- Officers and Executives

Respondents were instructed to enter a response of "N/A" for increase programs that do not exist in or were not applicable to their organization, and to enter a response of "0%" for programs that exist but were budgeted to receive no increase for the year in question. 0% responses were included in the calculations for the figures reported here.

Statistics for the following increase programs were collected:

- General/Cost of Living Increases: Increases that are granted to all eligible employees, typically in an "across-the-board" manner
- Merit Increases: Increases granted based on individual employee performance
- Other Increases: Any other increase granted during the course of the year (for example, equity or market adjustments)
- Total Increases: The sum of increases granted over the course of the year
- Salary Structure Increases: Increases made to salary structure control points in order to align structures with current market rates

Conrad_Confidential_Exhibit_A73- World at World: No definition provided in survey. Use term "merit increase".

Salary Budget Increases, by Type of Increase

General Increase/COLA	[redacted]
Merit Increase	
Other Increase	
Total Increase	

Conrad_Confidential_Exhibit_A74 – Mercer: See definition in illustration below. Mercer uses the term "salary increase budget".

Salary Increase Budgets

Organizations were asked to report their actual 2020 and projected 2021 salary increase budgets, as a percentage of total office and field base salary payroll, for all office and field employees. These figures exclude compensation budget increases in respect to promotion, reclassifications and/or new hires.

Conrad_Confidential_Exhibit_A75-Willis Towers Watson: No definition provided in survey. Use term "merit increases % of salary" and "total increases % of salary".

c. The 3.2% increase is not the projected average increase for the workforce. The average increase projected for the workforce is not used for determining the cost of labor. The merit budget of 3.2% of salary is used.

d. The 3.2% increase is not the projected increase for individual continuing employees. The average increase projected for individual continuing employees is not used for determining the cost of labor. The merit budget of 3.2% of salary is used.

Amy M. Conrad
April 28, 2021

Part III Filing Requirement:

For the Historic Test Year through the Projected Test Year, describe all salary increases that could apply to union employees, as well as non-union employees, e.g. Cost of living, step, etc. Specify when each type of salary increase could apply, e.g. monthly, quarterly, annually, etc.

Response:

Below is a description of the type of salary increase that adjusts base salaries (regular pay) for union and non-union employees.

Union Employees:

Operating Maintenance & Construction

Cost of Living – If in March of any year the Consumer Price Index for that March exceeds such index for the previous March by more than equivalent to 33 cents, an additional 1 cent for each full 0.4 point increase in the Index over the 33 cents shall be added to the then current Standard and Starting rates in conjunction with the first Monday in June general wage rate adjustments of that year.

General Wage Increase – Contractual 3% increase in salary effective the first Monday in June of each contract year.

Merits – At intervals of six months each, each employee is eligible for a merit increase subject to the following rules:

(a) Such increase shall be in the amount of twenty-five cents per hour (or $10.00 per week for weekly rated jobs) except that the last increase shall be an amount required to reach the Standard Rate of the job which he/she is assigned, but not to exceed thirty-five cents per hour, provided, however that the case of certain job classification which shall be in the amount of 25 cents per hour for each of the first 6 such increases and 50 cents per hour for each of the last two such increases.
(b) No employee shall be paid more than the Standard Rate of the job which he/she is assigned.

Promotions – Increase in labor grade. Employee shall receive twenty-five cents per hour increase or the Starting Rate of the job to which he/she is promoted , or fifty-cents below the Standard Rate of the job to which he/she is promoted if at the time of promotion the employee has three or more years of seniority in the occupation group of the job to which he/she is promoted, whichever is greater.

Premiums – Increases in regular pay for differentials in shift (such as holiday, night or weekend), on-call and storm. The following is a summary of the premiums:

- Saturday premium 25% of employee’s straight-time rate
- Sunday premium –50% of employees straight-time rate
- Night premium –afternoon premium of $2.50/hr and evening premium of $3.00/hr.
- On-Call during the workweek: 2.0 hrs per day during his/her scheduled workweek.

- On-Call during first & second off-duty days and holidays: 3.0 hrs per day

- Storm –double time or 2x
- Holiday- 100% of employee's straight time hourly rate for all hours worked

Virtual Call Center

General Wage Increase – Contractual 3.5% increase in salary effective the first Monday in August in contract year one. Contractual 3% increase in salary effective the first Monday in August in contract years two through five.

Merits – On the first Monday on or after April of each year, each employee is eligible for a merit increase, subject to the following rules:

(a) Such increase shall be in the amount of fifty cents per hour, except that the last increase shall be an amount required to reach the Standard Rate of the job to which she is assigned, but not to exceed fifty cents per hour. Any such increase shall be prorated due to any Non-FMLA related absence(s) from work of 20 or more days in the preceding 12-month period, except for paid personal absences or approved unpaid personal time offered to employees on a day-to-day basis.

(b) No employee shall receive a merit increase unless their work performance during the last 12 months interval meets expectations or higher.

(c) If an employee receives a disciplinary layoff, they shall receive a prorated merit increase.

(d) A temporary assignment shall not serve to extend the 12-month interval referred to herein.

(e) Merit increases shall become effective as of the first day of the workweek in which the increase is granted.

(f) Newly hired and promoted employees shall receive a prorated merit increase.

Premiums – Increases in regular pay for differentials in shift (such as holiday, night or weekend). The following is a summary of the premiums:

- Holiday- 100% of employee's straight time hourly rate for all hours worked
- Saturday premium –6% of straight-time rate or $1.00 per hour, whichever is greater
- Sunday premium –25% of employees straight-time rate
- Night premium –6% of straight-time rate or $1.00 per hour, whichever is greater

Zeeland

Promotions – Increase in labor grade. Employee shall receive an increase to bring the employee to the Starting Rate of the job to which he/she is promoted.

General Wage Increase – Contractual 3% increase in salary effective the first Monday in October of each contract year.

Premiums – Increases in regular pay for differentials in shift (such as holiday, night or weekend). The following is a summary of the premiums:

- Schedule - 5% of the employee's hourly rate for all hours worked outside of a normal daylight schedule.
- Holiday - 100% of employee's straight time hourly rate for all hours worked
- Schedule Change –150% of employees straight-time rate for the first day of the new schedule

Non-Union Employees:

Merits – Merit rewards are for the achievement of goals and objectives, accomplishment of tasks, duties and responsibilities established annually for each individual employee.

Promotions – is an increase in to pay for the addition of higher-level responsibilities resulting from attainment of knowledge, skills and ability through relevant work experience with a corresponding increase in salary grade. Salary increase amount is based on performance rating and position to market (actual pay/market value of job) and ranges from 7% to 15% depending on the change in role. For example, a promotion from a union or non-exempt role is typically 15% and a fully contributing exempt employee promoted to an exempt role would receive a 7% increase.

Developmental Increases – is an increase in to pay recognition of an employee's performance due to a change in responsibilities with no corresponding increase in salary grade. For example a

- Transfer to another department or
- Significant change in responsibilities of current job but not enough of a change in job value to warrant a salary grade increase.
- Addition of supervisory/lead responsibilities outside of the job family existing responsibilities which do not qualify for a promotional increase under the job family progression

Salary increases range from 0% to 4% based on an employee's performance and position to market (actual pay/market value of job).

Market Adjustments – Annually market data is reviewed for benchmark jobs. After reviewing the data, if a salaries for employees in critical job or jobs fall significantly below the market (at least 10%), then a salary adjustment may be provided to impacted employees to move their salary closer to the market value. No market adjustments occurred in 2019.

Premiums – Increases in regular pay for differentials in shift (such as holiday, night or weekend) temporary assignments and on-call. Employees in salary grade 18 and below may be eligible for the following premiums:

- Saturday premium 25% of employee's straight-time rate
- Sunday premium –50% of employees straight-time rate

- Night premium –6% of straight-time rate or $3.00 per hour, whichever is greater
- Holiday-100% of employee’s straight-time rate
- Schedule Change –100% of employees straight-time rate for the first 8 hours worked
- On-Call – workweek: 1.0 hr pay per day off duty/holiday: 2.0 hr pay per day

A non-exempt employee who is temporary assigned to a higher nonexempt position for one week or more at a time, will be paid a premium of 5% of current straight-time rate, in addition to his/her regular salary, for all hours worked, regardless of other premiums paid. However, if such assignment is to an exempt positon, this rate will be 12.5% and if the assignment is to a supervisory position, the employee is eligible for premium pay on a daily basis.

The following tables describe salary increases that adjust base salaries for union and non-union employees and the impact on Historic Test Year through the Projected Test Year.

UNION

Type of salary increase	Frequency of salary increase	Historic Test Year 2019	Projected 2020	Projected 2021	Projected Test Year (2022)
Cost of Living	Annual	$0.02	$0.00	$0.00	(1)
General Wage Increase	Annual	Varies by union group. See included amount above.	Varies by union group. See included amount above.	Varies by union group. See included amount above.	Varies by union group. See included amount above.
Merits	Varies	(2)	(2)	(2)	(2)
Promotions	Varies	(2)	(2)	(2)	(2)
Premiums	Varies	(2)	(2)	(2)	(2)

(1) COLA is anticipated to be zero for the projected test year.
(2) Salary increases are not presently budgeted or forecasted at this level of detail.

NON-UNION

Type of salary increase	Frequency of salary increase	Historic Test Year 2019	Projected 2020	Projected 2021	Projected Test Year (2022)
Merits	Annual	3.2% of base salaries	3.2% of base salaries	3.2% of base salaries	3.2% of base salaries
Promotions	Service anniversary or fill vacancy	(1)	(1)	(1)	(1)
Developmental Increase	Change in job responsibilities or fill vacancy	(1)	(1)	(1)	(1)
Market Adjustment	Annual, if necessary	(1)	(1)	(1)	(1)
Premiums	Varies	(1)	(1)	(1)	(1)

(1) Salary increases are not presently budgeted or forecasted at this level of detail.

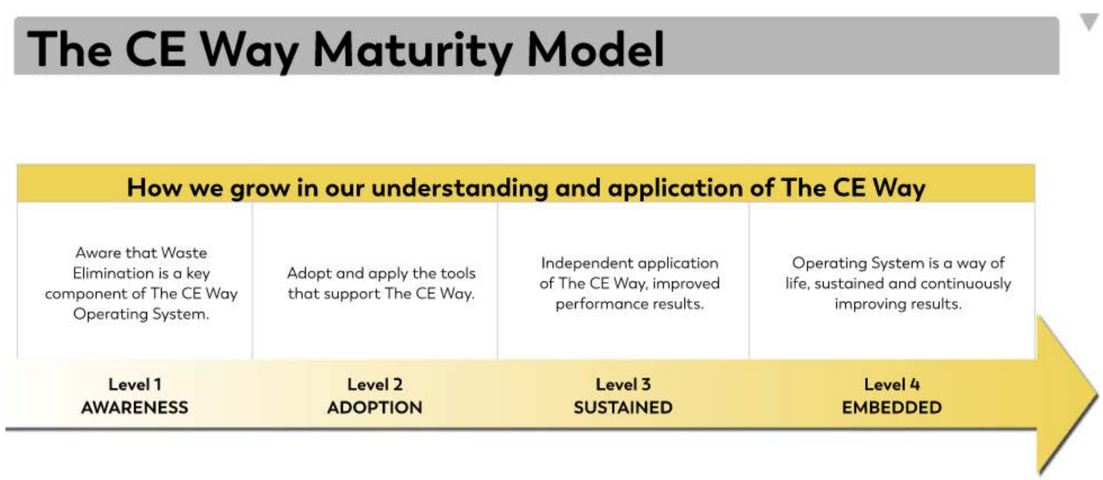
Question:

For the following questions, please refer to the Direct Testimony of Michael A. Torrey.

61. Refer to page 7, lines 1-5.
a. Has the Company established cost reduction or productivity improvement goals as part of the CE Way? If so, what are those goals?
b. Has the Company documented cost reductions or productivity improvement results to-date as part of the CE Way? If so, what are those results?
c. Has the Company projected cost reductions or productivity improvements that will result from the CE Way? If so, what are those projections?

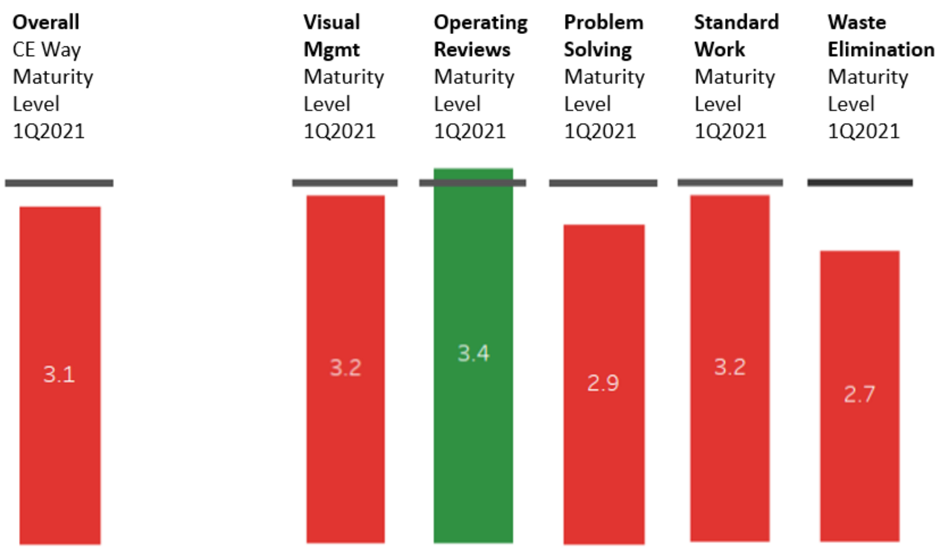
Response:

a. The Company's use of the CE Way is based on four basic plays consisting of visual management, operating reviews, problem solving, and standard work. The four basic plays work together to support a repeatable and structured lean operating system that can be deployed across the Company. Visual management and operating reviews support timely and informed communication which increases the speed and quality delivered to the customer. Problem solving leads to improved standards, automation, and process efficiencies. The application of the four basic plays is measured through quarterly maturity assessments in which employees' self-rate their understanding and usage of the plays. The Company set a goal to achieve an overall maturity assessment score of 3.3 by the end of 2021. Applications of lean business principals in a large corporation is a multi-year journey, and the Company will continue to focus and improve on the four basic plays over time.



The result of executing on the four basic plays across the Company is waste elimination. The Company has a waste elimination goal to identify $35 million of O&M savings in 2021 collectively for electric and gas operations. These savings translate to increased efficiency and allow more work to be completed for the same cost. The savings is measured as a reduction of human struggle hours or dollar savings that can be redeployed to achieve our budgeted or authorized spend levels.

b. As shown in the graph below, the Company's overall CE Way maturity assessment score in the first quarter of 2021 is 3.1 versus a year-end target of 3.3. The maturity assessment levels indicate the Company is above target for operating reviews in the first quarter of 2021.



Actual O&M waste elimination is tracked at the highest organizational level of the Company, and it reflects elimination of non-value-added effort.

The following examples illustrate waste elimination projects completed by the Company and demonstrate how savings were leveraged to complete additional work for the same cost.

- **Pre-Filled Bags of Dirt -** Electric line crews use prefilled bags of dirt when setting new poles. A team of employees recognized the bags were available at a lower cost from a local supplier. Changing this process lowered construction costs allowing the Company to complete additional projects for the same amount of money.

- **TTC Power App –** Vendor supplied Temporary Traffic Control (TTC) on a construction site averages $1,400 per day, and the expense is stopped only when the vendor is notified materials can be picked-up. To avoid a delay in the notification, a mobile app was developed with a projected two-year savings of $538,000 of capital and $195,000 O&M. This savings lowers the costs of projects that involve temporary traffic control and allows additional projects to be completed for the same budget.

- **ETR Machine Learning Model**: A machine learning model was applied to the Company's Estimated Times of Restoration (ETR) during storm. By automating this formerly manual process, the Company was able to reduce 1,040 hours of human struggle and save >$250,000 from the elimination of the ETR storm role. The savings could then be applied to support other value-added roles during storm restoration.

c. While the Company has projected O&M savings associated with waste elimination, formal plans to achieve these targets have not been established. Current projections are focused on 5% year-over-year O&M savings. However, the Company will adjust projections as appropriate to respond to changing conditions in the business. As we deploy the CE Way across the enterprise, savings can be redeployed into the business and ultimately help us to achieve more work at similar costs for customers. It also allows us to address underfunded areas that require such a reinvestment.

Michael A. Torrey

Michael A. Torrey
April 28, 2021

Rates and Regulation

Question:

14. Refer to Consumers Energy's response to U-20697-MEC-CE-1416.

   a. Please confirm that Consumers Energy currently bases transformer sizing on Annex G of IEEE/ANSI Standard C57.91-1995. If not, identify the transformer sizing standard that Consumers Energy currently uses.

   b. Please provide a working copy of the Transformers Loading Capability (TLC) Program that is currently used by the Company to calculate recommended kVA rating for substation transformers, together with any user instructions for that software.

   c. Assuming that the TLC Program uses ambient temperatures in calculating substation transformer loading or recommended ratings, please identify the Company's practices for obtaining and using ambient temperatures when using the TLC program.

Response:

a. The Company currently bases transformer loading capabilities on Annex G of IEEE/ANSI Standard C57.91.1995.

b. The instructions for the TLC Program are provided as Attachment 1 to this discovery response. However, the TLC Program runs on an operating system that, for cybersecurity purposes, is no longer supported by the Company's network. The Company maintains a copy on a computer isolated from the network. Therefore, the program cannot be provided. A replacement application called LOIT has been developed and is under review for adoption as a replacement for the TLC Program.

c. Ambient temperature data from airport temperature data sources is reflected in average ambient histogram bins. Each bin is then represented by an ambient temperature profile. Each profile is used during the iterative algorithm's identification of a set of transformer specific loading capabilities. The data analyses were conducted based on a multi-year period. It is anticipated a new set of ambient data will be processed and implemented as part of the migration to the LOIT application.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Transformer Loading Capability (TLC) Program

Version 1.05

User's Guide

NOVEMBER 9, 2000

CONTENTS

Introduction

The Transformer Loading Capability (TLC) Program was developed to assist in the complicated business of establishing transformer loading limits. It is based on the latest IEEE loading guide and as such offers some of the most advanced transformer thermodynamic modeling capabilities known at this time. Additionally, it offers many of the conveniences afforded by the modern desktop computer running Windows NT 4.0. With these facts in mind, it is the intention of this document to provide for a basic understanding of the TLC Program, its usage, and its limitations.

Installation

System Requirements

The TLC Program was designed to run on a Windows NT 4.0 Workstation. Approximately 15MB of free disk space are required on the local drive that contains the "Program Files" subdirectory. The "setup" program that installs TLC decompresses all of the required program files from the network and installs them in the appropriate location(s) on your local drive. A predetermined directory tree is used and should not be modified by the user. The TLC Program relies on a variety of data files, which can be installed by the user, after the program has been installed.

Installing the TLC Program

The TLC Setup.exe application ("executable") file is located in the "K:\Sds_cad\genview\transcap\install TLC 1.05" directory. There are several ways to run this application. The following is one way:

1. Click on the "Start" button on the task bar.
2. Move the mouse pointer to the "Run" menu item and click again.
3. A dialog box titled "Run" will appear. Click the browse button.
4. Navigate the directory tree using the "find in" combo-edit box and/or the "up directory" button in order to find, first the "K" drive, then the path "\Sds_cad\genview\transcap\install TLC 1.05", and finally the "Setup.exe" application file. Highlight the file with the pointer and then select the file with the "ok" button (or by double clicking on it). This should bring you back to the "Run" dialog.
5. The setup file with its full path should show up in the "Open" combo-edit box. Run the setup program by clicking the "ok" button. The program should start and carry you through the installation procedure. Clicking on "ok", "next", and/or "finish" buttons is all that should be required. If other scenarios are encountered refer to the Technical Support section of this document.
6. The TLC program can now be executed from the "Start-Programs" menu.

Removing the TLC Program

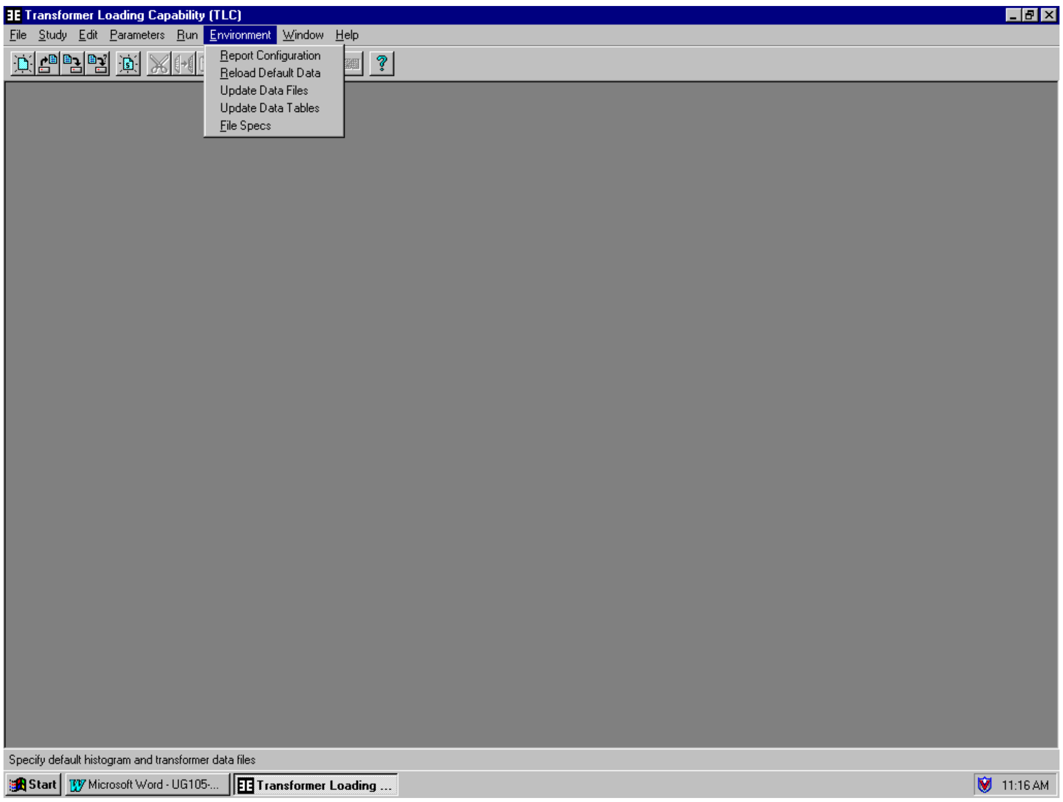
Periodically, upgrades to the program will be made (or bugs will be fixed). This will most likely require that the old version be removed and then a new setup application be run. To remove the TLC Program, complete the following steps:

1. Click on the "Start" button on the task bar.
2. Move the mouse pointer to the "Setup" menu item and wait for the Settings sub-menu to appear.
3. Point to the "Control Panel" menu item and click. This will launch the Control Panel Application.
4. Point to the "Add/Remove Programs" application and click.
5. You should see an "Install/Uninstall" property page ("tabbed page"). Highlight the TLC 1.05 program and remove the program by clicking the "ok" button.
6. The removal application will remove all of the files that the setup program installed and it also undo the registry changes that the setup program made upon TLC installation. You may be prompted to remove shared files. You should respond to these prompts by clicking "no" (or "no to all").

Installing/Updating TLC Data Files

Once the program is installed, the standard data files and tables need to be installed. Installation of these files is required at least once after the initial program installation. The same files can also be updated later as new or updated data files become available.

The user can install the standard data files by clicking on the “Update Data Files” menu item on the “Environment Menu”. The program will then run the “updata.bat” file (which resides in the same directory as the TLC executable) which will simply copy the data files from the master directories on the network k: drive into the appropriate local directories. Once the data files have been copied, the user should also update the data tables using the “Update Data Tables” menu item (also on the Environment Menu).



Technical Support

At some point in time questions will arise concerning the TLC program that this guide does not address. It is also conceivable that bugs will be discovered. In such cases, Gary Schauffler, Carol Gerou, or Fran Huguet can be contacted for assistance. Ultimately, TLC maintenance will be exclusively Carol Gerou’s domain.

Transformer Loading Capability Modeling

The TLC program was designed to allow for three different types of studies to be performed: Single Transformer Simulation, Single Transformer Maximum Loading, and Multiple Transformer Maximum Loading. The first of these study types, Single Transformer Simulation, is geared toward "Power Control" type (or emergency planning) applications where given loading and ambient scenarios are to be evaluated (off-line) for the purpose of constraint violation monitoring/prediction. In effect, this mode is for modeling a single day's thermal scenario. The second study type, Single Transformer Maximum Loading, is geared toward "Planning" tasks in which maximum loading data are predicted for a given transformer, which is subjected to *typical* loading and ambient scenarios. The results of this type of study reflect aggregate annual aging considerations. Finally, the third study type, Multiple Transformer (or Batch) Maximum Loading, is an extended version of the Single Transformer Maximum Loading type study that allows several transformers to be studied at a time. The cores of all three study types are based on an expanded version of the latest IEEE transformer thermal modeling algorithm.

Core Algorithm

Annex G of IEEE C57.91-1995, Guide for Loading Mineral-Oil-Immersed Transformers, defines a thermodynamic model that is applicable for liquid-immersed distribution and power transformers. This *new* model allows ambient temperatures and loading to be modeled as piecewise linear functions of time (i.e., "profiles"). Whereas, older models typically assumed the ambient temperature remained constant throughout the given load cycle. Additionally, the new model considers a variety of other parameters including: type of fluid, cooling mode, duct temperature rise, resistance, and viscosity changes. The TLC program was built around a slightly modified version of this model. The modifications allow for a basic level of harmonic modeling. It should be noted that these modifications have no effect when only fundamental loading data is modeled. Additional modeling enhancements are being researched by Maria Pedula (the current CE-MTU Fellow). These enhancements should allow for the inclusion of supplementary cooler effects. Further details of the Annex G algorithm are left to the actual guide.

Loading Mode

The core algorithm models the heat flow in a given transformer subjected to: initial temperature conditions, a given day's varying load, and the associated varying ambient temperature. The only unknown data are the initial temperature conditions. These include such data as the initial top oil temperature, the initial hot spot temperature, and the initial average winding temperature. The initial temperatures are effectively a function of "yesterday's" thermal scenario. Was yesterday the same as today?… if so the "Loading Mode" is dubbed "Cyclic", if not, then the loading mode is dubbed "Acyclic".

Both Cyclic and Acyclic scenario modeling relies on the fact that as time goes by, any errors due to errors in initial conditions will eventually become insignificant (given cooperating time constants, etc.). For Cyclic Loading, the program executes the core algorithm twice with the same ambient and load data for each "run." The first time with default initial temperatures, and the second time starting with the final temperatures from the first. Thus, the final values of the first ("initial") run serve as the initial conditions for the second ("target") run.

Acyclic scenario modeling is accomplished by simulating two different thermal scenarios (e.g., yesterday's and today's), once again, using the end results from the first scenario as the initial conditions for the second.

Although highly unlikely, the user may know the initial temperatures and may choose to supply them directly. This direct entry contingency is also considered Acyclic Loading.

The distinctions between the loading modes are important when defining a study. Figure 1. summarizes the different loading modes.

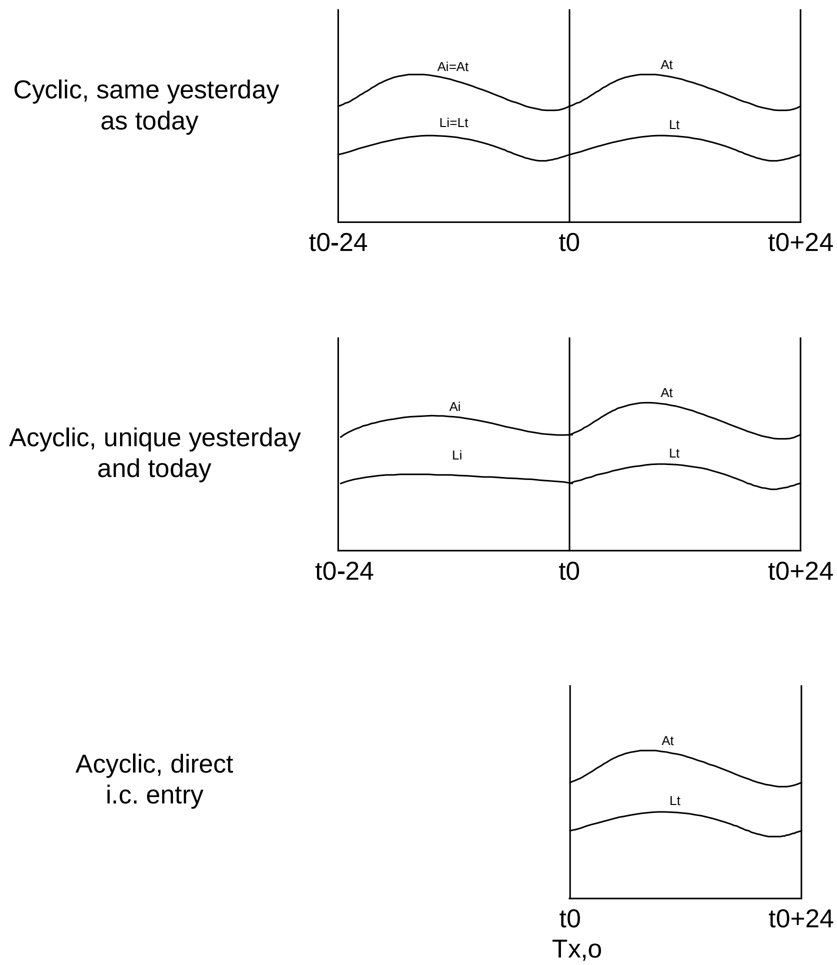


Figure 1. Loading Modes

Loading Profiles

For historical reasons, the program allows two different types of load profiles: Synthetic, and Multi-Segment. The first of these, Synthetic, is a simple two step load profile. Preload, peakload, peak start time, and peak duration data are sufficient to fully define a Synthetic load profile. Multi-Segment profiles are defined by piecewise linear segments. A special load profile data file must be created for each unique Multi-Segment load profile (see Appendix C). Whereas, synthetic profiles are defined via program dialoging (i.e., prompting).

Ambient Profiles

As mentioned earlier, the new model can handle a varying ambient temperature. This capability adds an important dimension of realism to the modeling because the impetus of heat transfer is a temperature differential. When the ambient temperature is high (e.g., “high noon”), heat transfer from a transformer to the ambient is reduced relative to that occurring during the cooler parts of the day. Thus, the heat generated by the various transformer losses is not removed and therefore raises the temperature of all of the transformer’s materials. The old model was deficient in the ambient modeling area.

The program requires that each ambient profile be stored in an ambient profile data file. Once again, as was the case for load profiles, ambient profiles are represented as piecewise linear functions of time. See Appendix C for further file formatting details.

Ambient Histograms

Ambient histogram data are used by the Maximum Loading Algorithms. It is through the use of histograms that the annual aging results are determined. A unique file format exists for ambient histogram data. Once again, refer to Appendix C for file formatting details.

Ambient Histogram files also allow for a reduction of load as a function of load type and average ambient temperature. This feature is discussed later in more detail.

Transformer Batches

A study can encompass one transformer or many transformers (i.e., a batch). A batch of transformers is defined in a 'batch maximum loading (bml) ' file which has a unique format. “Reject” and “output” files are also closely related to transformer batches. Appendix C details the format of all of TLC’s file types.

Study Types

Single Transformer Simulations

Simulations model the thermal behavior of a given transformer subjected to a given set of loading and ambient conditions. Hourly temperature data can be reported along with peak temperature data. Violations of any enforced constraints are logged. However, there is no limiting of loading to prevent constraint violation. It is a “see what happens” type of study. This is in significant contrast to a Maximum Loading Study, which has very different goals. The flowchart of Figure 2 characterizes the algorithm used by the program to perform a Simulation.

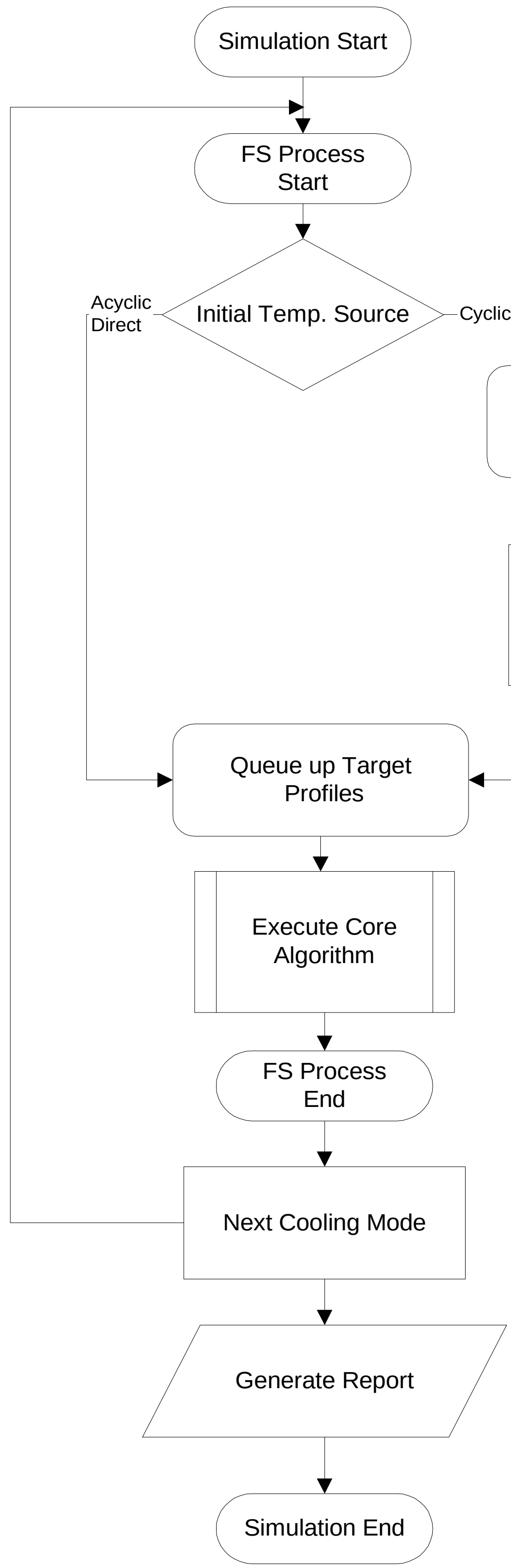


Figure 2. Single Transformer Simulation Algorithm

Single Transformer Maximum Loading Study

The goal of a Single Transformer Maximum Loading Study is to determine the maximum loading capability of a given transformer that is subjected to: a given loading profile, given annual ambient conditions, and a given set of constraints.

Annual ambient temperature data has been separated into two seasons: Summer, and Non-Summer. Summer is three months and Non-Summer is nine months. The old capability program dealt mainly with Summer and then made some "simplifying" assumptions to determine Winter capabilities. With the new daily aging calculations and the absolute concept of "Annual Loss of Life (ALOL)", the simplifying assumptions are no longer made. Effectively, these assumptions did not count Winter aging against the ALOL. This is no longer the case. The Non-Summer daily agings , although small, do accumulate due to the shear number of days in the season. With this in mind, the Summer vs. Non-Summer division was chosen to provide some level of continuity between the old and the new capability results. The continuity effect is most evident when comparing old and new Summer capabilities.

The TLC Program requires that a user split the total allowed ALOL into a Seasonal Loss of Life (SLOL) for Summer and another for Non-Summer. For example, if an ALOL of 10% is prescribed, it must be broken up, one allotment can be used (i.e., "burned up", no pun intended) by the Summer season, and one allotment by the Non-Summer season. This split is accomplished via a Summer SLOL/ALOL ratio. Thus a 0.3 S/A LOL ratio, given the 10% ALOL, would allot 3% for Summer, and 7% for Non-Summer. The numbers are for example only. In this way, ALOL is really an annual term.

At this point in time, courtesy of the Asset Utilization Project, the Summer target SLOL has been reaffirmed at 3%. Non-Summer (a.k.a., Winter) SLOL is also set at 3% for a total ALOL of 6%. Once again keep in mind there is a major discontinuity in approach between old and new "Winter" capability estimation, with the new program being rooted in consistency of methodology. Also, note that a transformer's load typically peaks in one season or the other... in which case the opposite season's allotted SLOL is never truly consumed.

Each of the seasons requires ambient histogram data encoded appropriately into an associated histogram file. Originally (in TLC Version 1.00), the two histogram files were generated from 10 years worth of Grand Rapids, MI ambient temperature statistical data. However, Karl Grieve developed an application that generates histogram files from several airport temperature sources. Thus, TLC can now use location specific ambient histogram data for its capability calculations.

The Single Transformer Maximum Loading Algorithm (SMLA) iteratively determines the maximum acceptable loading by adjusting the given load profile up (or down) until a constraint violation occurs (or ceases), all while the transformer is subjected to the worst case ambient profile denoted in the respective season's histogram file. The algorithm backs off as a final step if appropriate. Once a maximum loading profile is established, the algorithm processes the current histogram to determine the SLOL while watching for SLOL violation. If none occurs, then a maximum loading profile has truly been located. However, if a SLOL violation occurs, the load profile is adjusted downward until the SLOL constraint is no longer violated.

SLOLs are determined by first calculating a given scenario's Daily LOL (DLOL) and then multiplying by the frequency of the occurrence of the given scenario's ambient profile. These LOLs are then accumulated as the algorithm marches through the ambient profiles specified in the associated histogram file. Load reduction factors are also applied as a function of the ambient profiles (i.e., effectively as a function of the average ambient temperature). The frequency and load reduction data are also located in the associated histogram file.

The program has another loop that repeats the maximum loading determination for each of three (or more) specific ALOLs: Emergency Loading, one (or more) User Defined Targets , and Zero Percent. Emergency Loading capability data is not constrained by the ALOL constraint. Rather it is limited only by the enforced, less subjective, physical constraints. User Defined ALOLs are adjustable and will elicit aging constrainment. Finally, Zero Percent ALOL is provided for the determination of capabilities that represent “Normal” loading. The term “Zero Percent ALOL” is a carryover from the old world. It is a misnomer because even rated loading results in a finite ALOL, and with the new aging calculations this LOL can be non-trivial. Because of this, the user can provide a target (currently 1%) value, which will serve as the Zero Percent LOL target.

Refer to the flowchart of Figure 3 for further clarification of the SMLA. Note that the Full Simulation (FS) Process is a sub algorithm of the Single Transformer Simulation Algorithm of Figure 2.

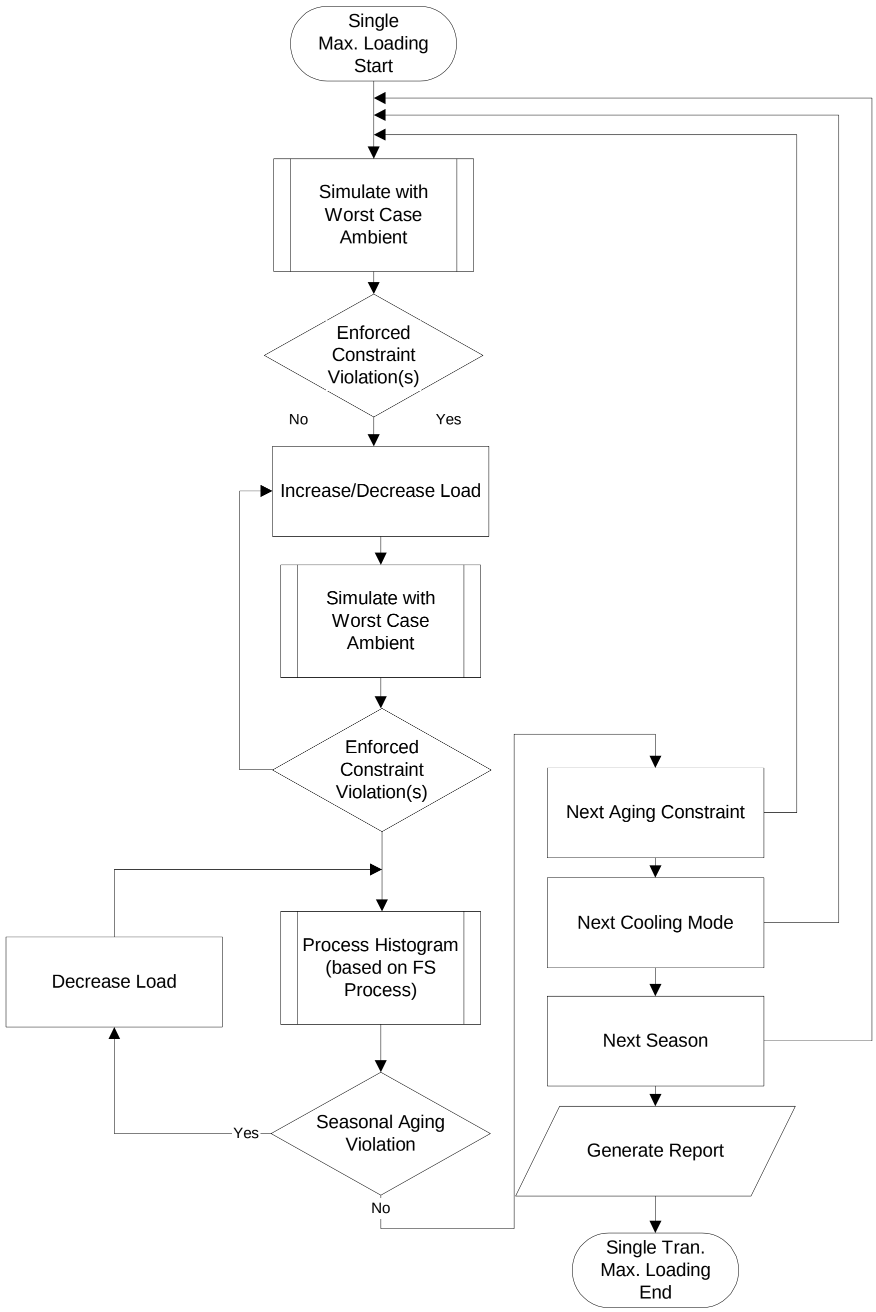


Figure 3. Single Transformer Maximum Loading Algorithm

Multiple (a.k.a. "Batch") Transformer Maximum Loading Study

The Multiple Transformer Maximum Load Study (a.k.a. "Batch Max") is just an automated form of the Single Transformer Maximum Load Study. Instead of the user manually providing a single transformer serial number and then selecting, entering, or editing multiple study parameters, the user provides a text file ("bml" type) that contains a list of serial numbers and then defines only a small set of study parameters. The Batch Max Study then marches through the batch file and processes each transformer. The data for each transformer is screened for major errors before processing. If bad data is encountered the serial number is added to a reject file along with an error code which should help locate the bad data. If the data is *good*, then the WD and Bank Number for the transformer are used to query a "location" database table in order to find what histogram, load type, and load files to use in the study. From there, a Single Transformer Maximum Load Study is performed assuming Cyclic Loading. Hot spot constraints are set based on a variety of transformer parameters. The process repeats for each transformer (i.e., serial number) in the batch. Figure 4 reveals the inner workings of this algorithm. Two reports are generated by a Batch Max Study: a Crystal Reports (CR) report, and a comma separated variable text file. The first of these is easier for viewing and provides volumous "friendly" output, whereas the second is more efficient and was designed for import into Excel.

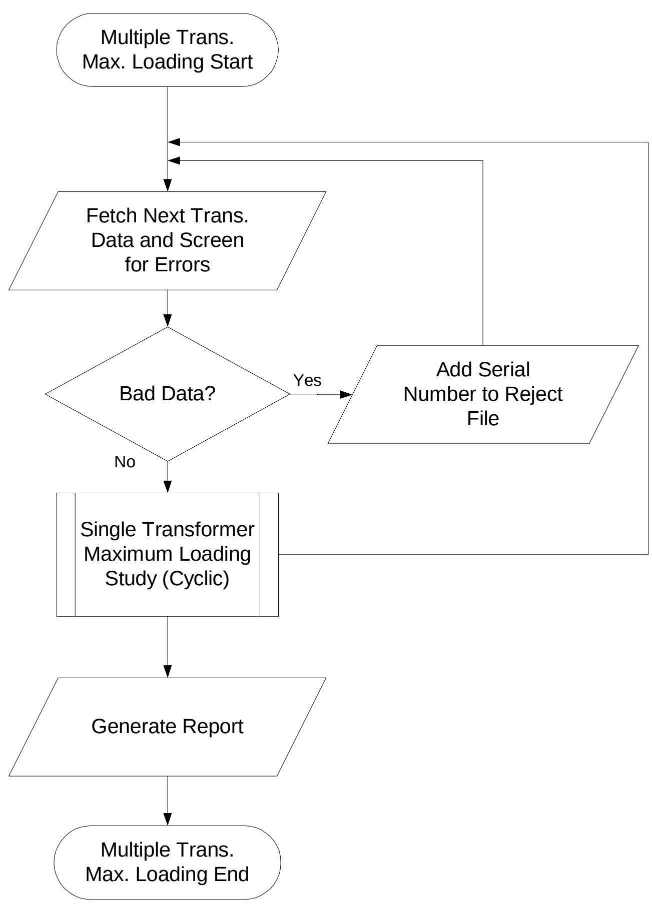


Figure 4. Multiple Transformer Maximum Loading Algorithm

Defining and Running Studies

The primary task of the TLC user is to perform ("run") a study. However, before running a study, a study must first be defined. Defining a study is simply telling the program what data to use and which one of the three study types to perform. This is accomplished through the user interface. The interface is similar to most Windows Application interfaces. It has menus, dialog boxes, property sheets, and message boxes.

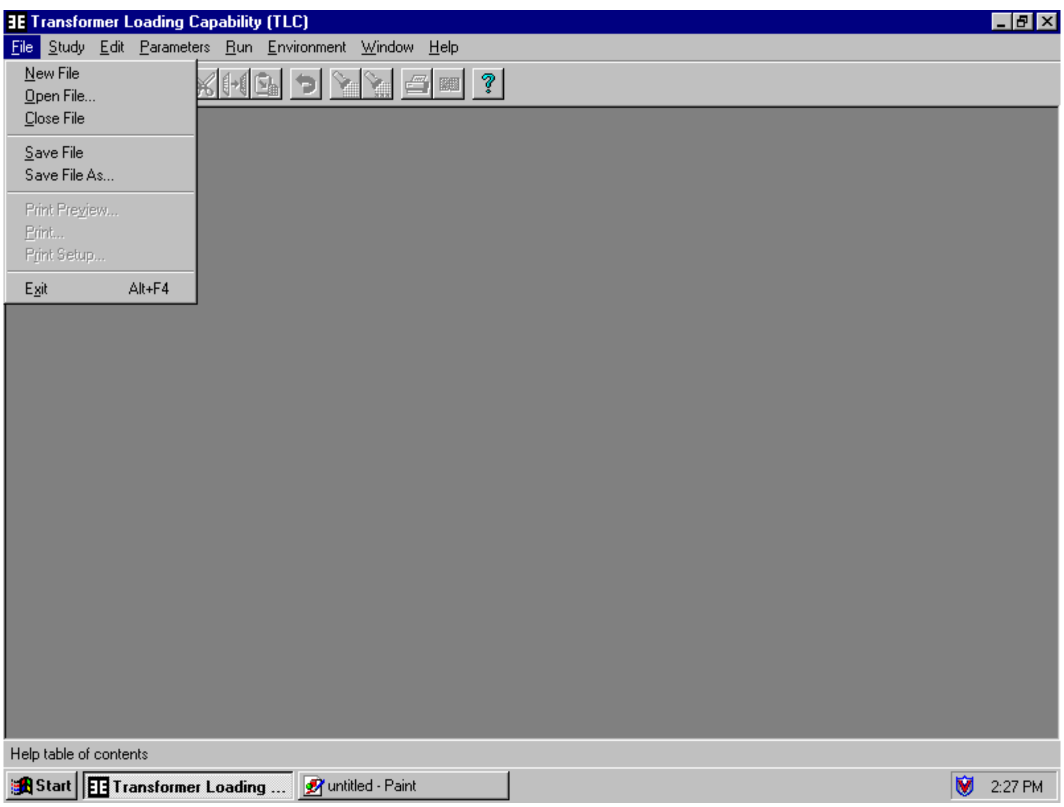
Although it is not practical to illustrate every possible study definition scenario, a few example definition processes have been included in Appendix E. The key to study definition is understanding the modeling options that are available. Once familiar with the modeling options, the study definition process simply leads the user along while gathering the required parameters.

TLC Interface

Menus

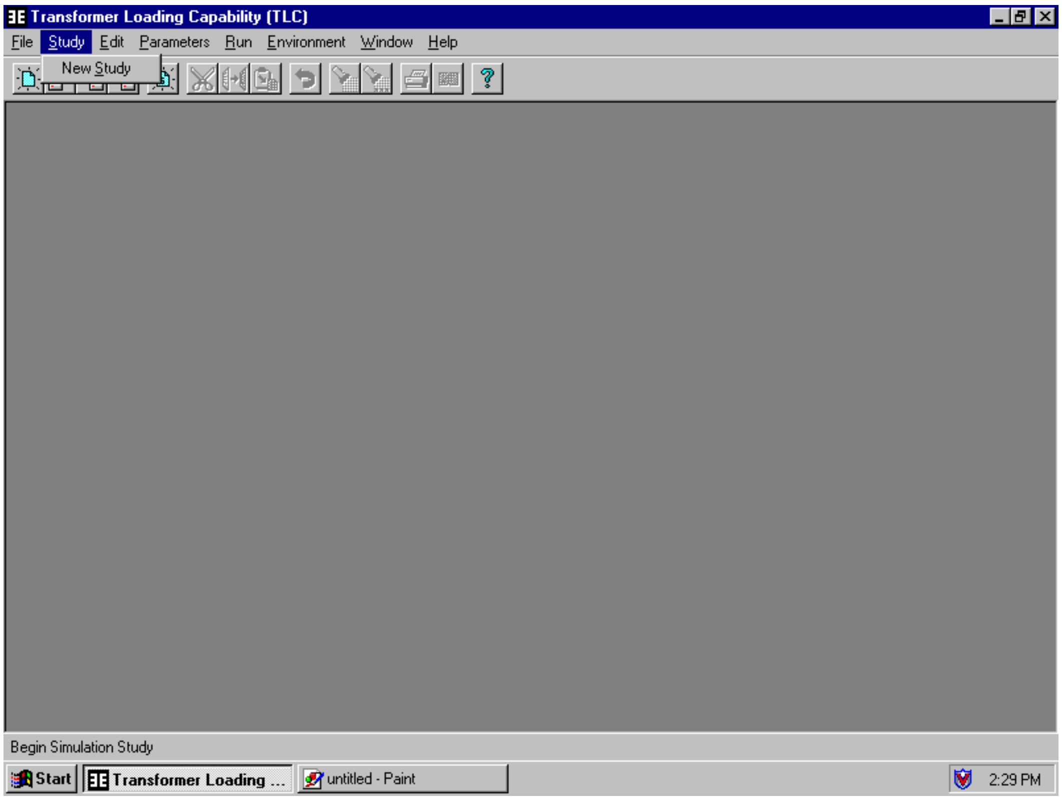
File Menu

The File menu is employed by the user when creating, opening, and closing TLC data files. Examples of file types a user may desire to create are: load data files, ambient data files, batch files, and histogram data files. These files can also be created and maintained by any standard ascii text editor. In any case, the files have strict formatting conventions which are defined in Appendix C.



Study Menu

The Study Menu is employed by the user when defining a new study. Studies can not be saved or retrieved. A study must be redefined if it is to be repeated at a later date. Selecting the “New Study” menu item from the Study Menu is the first step in defining a study. The definition process then unfolds as a function of the study type since each study type requires different data in order to run.

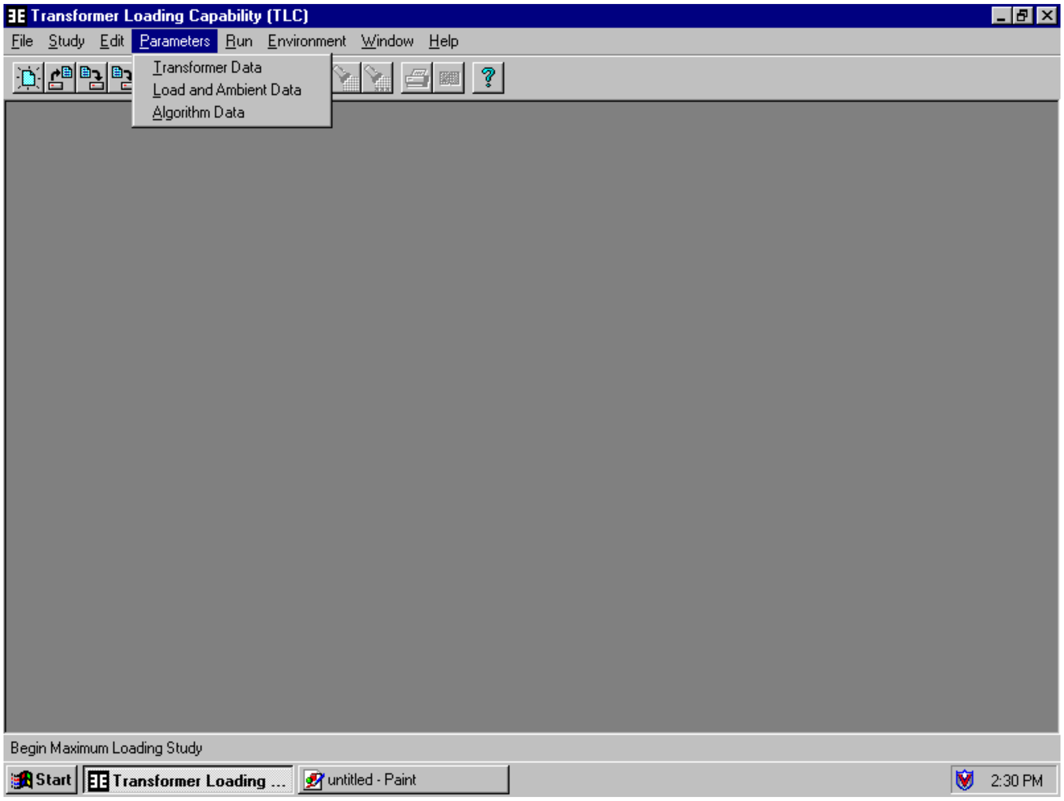


Edit Menu

The Edit Menu would typically be employed by a user to manipulate a TLC data file. It is self-explanatory and will be familiar to anyone who has used a text editor. It is only functional when a text file window is open.

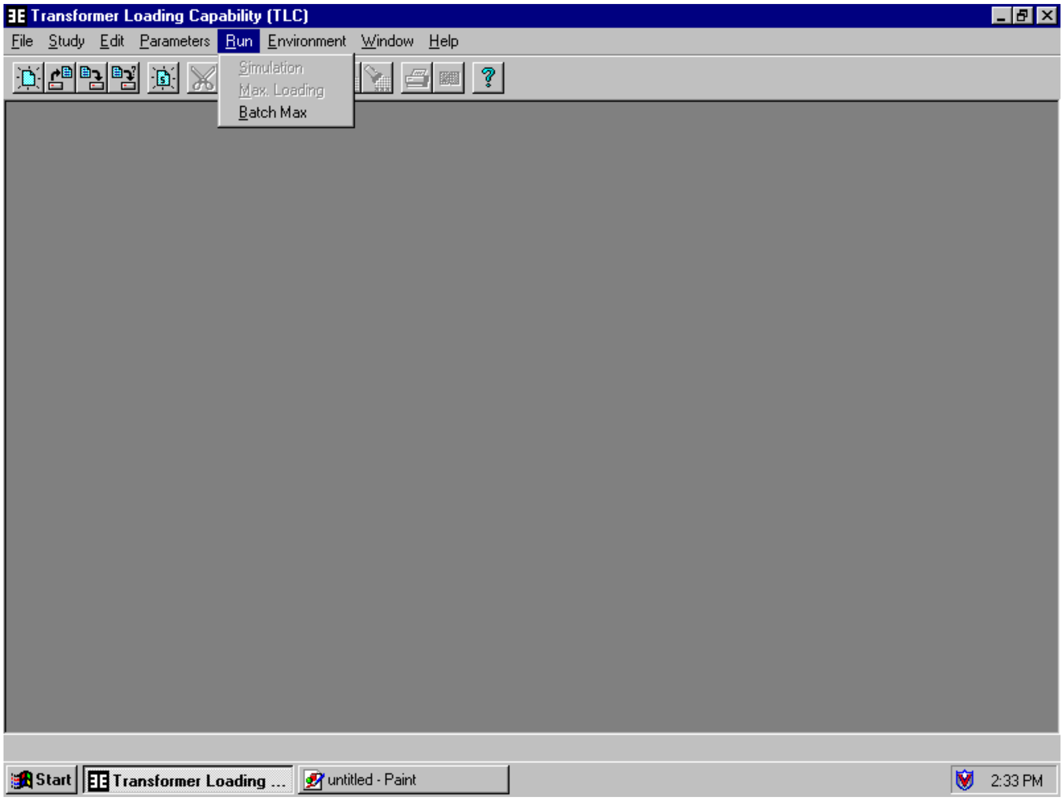
Parameters Menu

The Parameters Menu allows the user to revisit the key data property sheets which are used to define the data essential for study. It is impossible to define a study by accessing only the Parameters Menu. A valid study definition always starts with the "New Study" menu item on the Study Menu. Once an initial study is defined, the study data may be modified and run as many times as desired. However, a change in study type requires the use of the Study Menu.



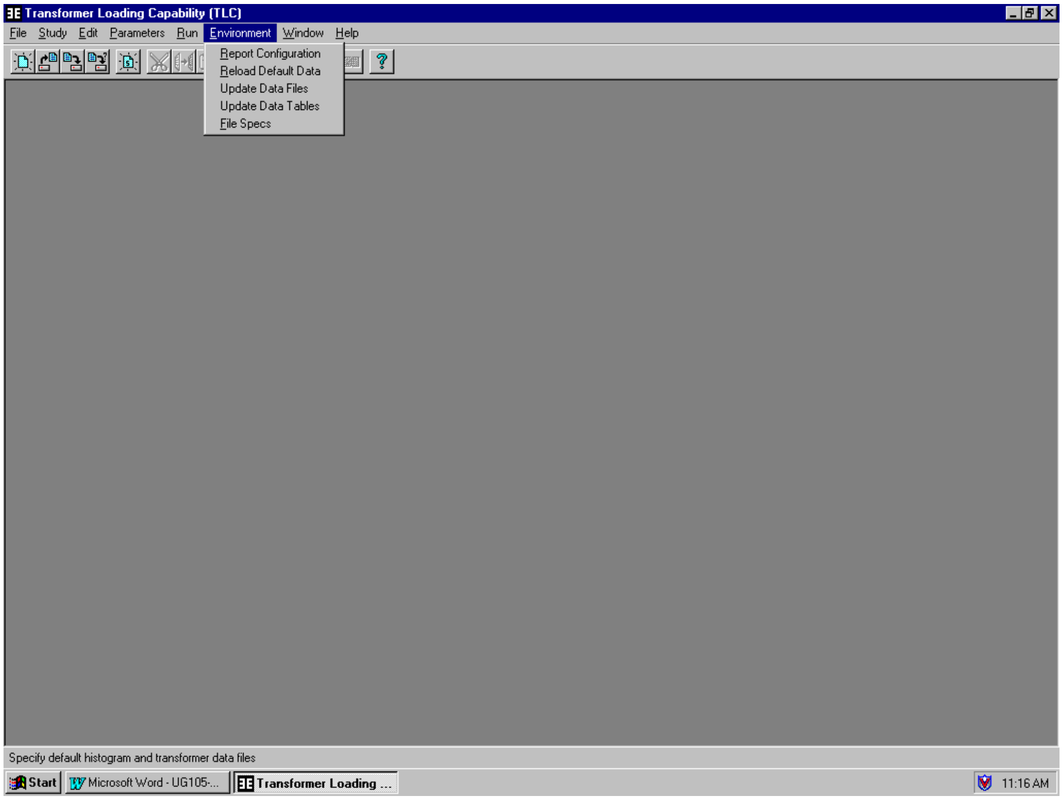
Run Menu

The user may run a study only after fully defining a study via use of "New Study". Subsequent runs can be simple variations of the original run by manipulating the study data via the Parameters Menu. Clicking on the appropriate Run Menu item will signal the program to perform the study.



Environment Menu

The Environment Menu provides access to property sheets and dialogs that allow for report configuration, data file updating, and the specification of key default data files. The most frequently used menu item here will be "Report Configuration," which allows the user to add a study title, his or her name, and/or comments to the report.



Windows Menu

The Windows Menu allows the user to arrange open windows so as to facilitate easy window manipulation as well as to provide an aesthetically pleasing screen environment. Once again, Windows users will be familiar with this generic menu.

Help Menu

The Help Menu provides access to basic level help functionality. The TLC Program currently has virtually no program specific online help; rather the help is concentrated in this document.

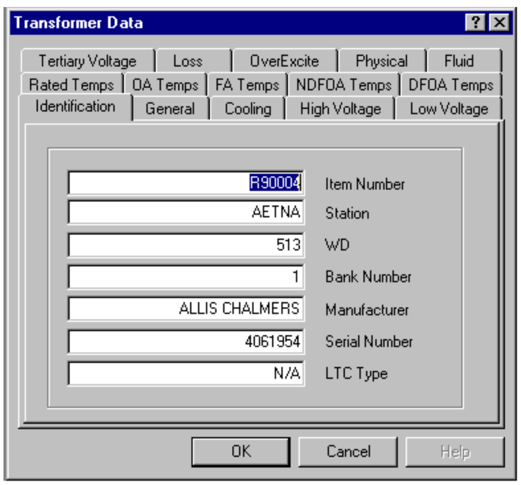
TLC Data

Transformer Data Property Sheet

The user encounters the Transformer Data Property Sheet when first defining a study. Subsequent access to the sheet is provided via the Parameter Menu. The Single Transformer Simulation and Maximum Load Study definition processes both prompt the user for a serial number. The serial number that the user enters is used to query the Transformer Data Table, which may or may not hold a record that contains all of the required data for the given transformer. If a record is not found, then the direct entry method must be used. However, if the record exists then the Transformer Data Property Sheet will appear and be filled with the data that was available from the table. The user will be notified if estimation of data was required. From there the user can review and/or edit the data before accepting the data with the “ok” button.

Identification Page

Data on the Identification Page is for documentation purposes only. The data is not used for modeling purposes.



Item Number: For information only. Refer to the “ITEM NUMBER” field in the Transformer Data Table, Appendix D.

Station: For information only. Refer to the “STATION 1” field in the Transformer Data Table, Appendix D.

WD: For information only. However, if the data existed for the supplied serial number in the Transformer Data Table and a Maximum Loading Type Study is being performed, then the WD and the bank number will be used to determine the appropiate load type, loading profiles, and histograms to use for the study. For a Single Maximum Loading Study, these data will serve as defaults. Refer to the “WD” field in the Transformer Data Table, Appendix D.

Bank Number: For information only. See WD comments. Refer to the “BANK NUMBER” field in the Transformer Data Table, Appendix D.

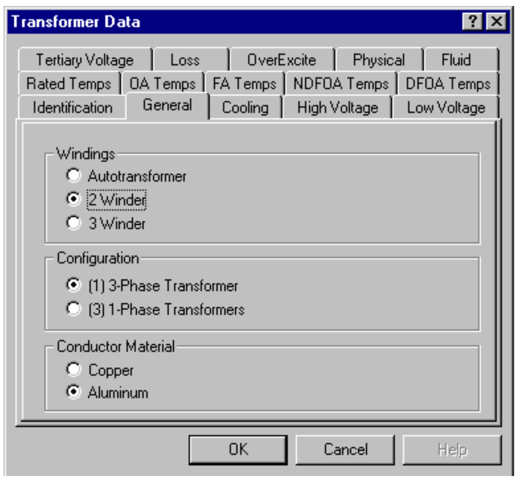
Manufacturer: For information only. Refer to the “MANUFACTURER” field in the Transformer Data Table, Appendix D.

Serial Number: For information only if directly entered, otherwise it was the "key" to the Transformer Data Table. Refer to the "SERIAL NUMBER" field in Transformer Data Table, Appendix D.

LTC Type: For information only. The model does not consider the LTC in any way, shape, or form. Refer to the "LTC TYPE" field in the Transformer Data Table, Appendix D.

General Page

The model employed by TLC doesn't specifically handle three winding transformers. This doesn't mean that they can't be studied; only those assumptions must be made to do so.



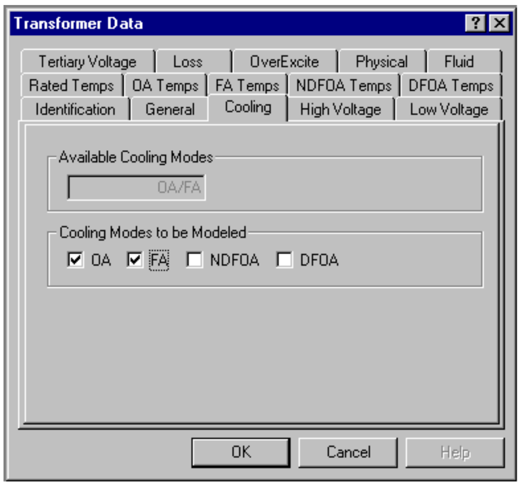
Winding Type: For information only. Refer to the "TRF WINDING TYPE" field in the Transformer Data Table, Appendix D.

Configuration: Important to bushing current calculations. Refer to the "PH" field in the Transformer Data Table, Appendix D.

Conductor Material: The model can't handle independent winding conductor material types. The effect of this parameter is typically minimal/negligable relative to the aggregate accuracy of the whole capability subject.

Cooling Page

In most cases, transformer data will be extracted from the Transformer Data Table. The "Available Cooling Mode" data will then reflect the nameplate cooling modes available for the given transformer. The program will automatically select the cooling modes to be modeled based on the available cooling mode data. OA cooling will always initially be selected, as the OA data must be present in any valid transformer data record (with the exception of pure FOA units). The program will estimate test data that is missing for the remaining cooling modes. The results for cooling modes which use estimated test data will not be as accurate, but are the most reasonable available, given the lack of appropriate test data. Cooling mode data for modes not supported on the nameplate will be partially filled, but will require additional data to be entered via the associated cooling mode property page (i.e., only if the unsupported cooling mode is to be modeled).

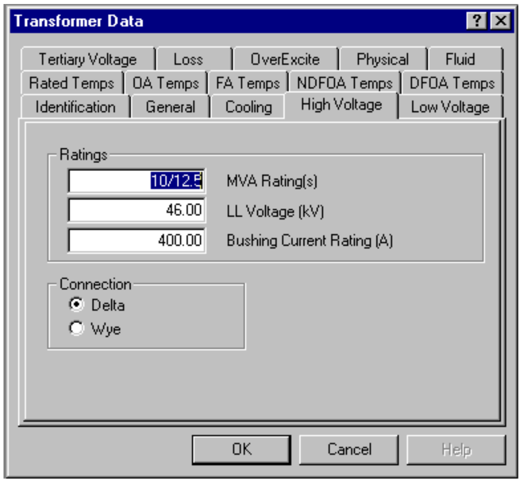


Available Cooling Modes: Mirrors the nameplate cooling modes. Refer to the "COOLING" field in the Transformer Database Table, Appendix D.

Cooling Modes to Be Modeled: Modes that are selected will be "studied" as long as all of the required data is available to do so.

HV/LV/TV Pages

These pages provide for the entry of basic rating and connection data. As noted earlier, tertiary data is only used for documentation purposes.



MVA Rating(s): Refer to the “MVA RATING HV WDG”, “MVA RATING LV WDG”, and “MVA RATING TV WDG” fields in Transformer Data Table, Appendix D.

LL Voltage: Refer to the “SUB HV PH-PH KV” and “SUB LV PH-PH KV” fields in Transformer Data Table, Appendix D.

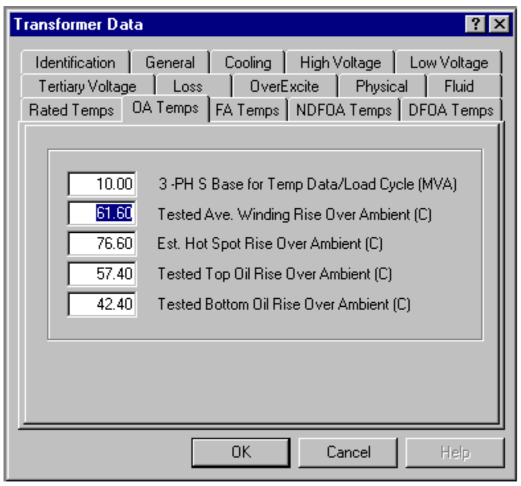
Bushing Current Rating: Refer to the “BUSHING AMPS HV” and “BUSHING AMPS LV” fields in Transformer Data Table, Appendix D.

Connection: Plays a role in bushing current calculations. Refer to the “SUBHVCON” and “SUBLVCON” fields in Transformer Data Table, Appendix D.

OA Temps, FA Temps, NDFOA Temps, DFOA Temps Pages

These pages allow for the entry of test data. Most of these data are available on the transformer test sheets. However, hot spot rise and bottom oil rise in the past were typically not available. Current and future transformer purchases should require at least the addition of the bottom oil rise data on the test reports.

The test data estimation routine starts by using the “TEMP RUN 1” data fields from the Transformer Data Table to fill in the test data fields for all modes: OA, FA, DFOA, and NDFOA. “TEMP RUN 2,” if it exists in the record, will then be written over the FA data or both of the FOA data fields in the respective property pages. During this process, the bottom oil test temperature is either supplied (if it existed in the record), or it is estimated based on Maria Pedula’s findings. These findings suggest a typical top oil to bottom oil temperature differential of 15 degrees for OA and FA modes, and 2 degrees for the FOA modes. Also, for all cooling modes, the hot spot temperature is estimated to be 15 degrees C above the average winding rise.



3-PH S Base for Temperature Data/Load Cycle: Typically the MVA rating for this cooling mode. Refer to the “TEMPRUN 1 MVA LOAD” field in the Transformer Data Table, Appendix D.

Tested Average Winding Rise Over Ambient: Average of the high and low voltage winding rises per the test data. Refer to the “HV WDG RISE RUN 1”, “HV WDG RISE RUN 2” , “LV WDG RISE RUN 1”, and “LV WDG RISE RUN 2” fields in the Transformer Data Table, Appendix D.

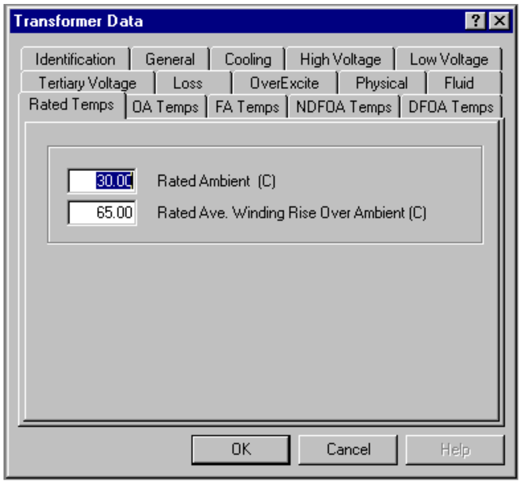
Estimated Hot Spot Rise Over Ambient: At rated conditions. Typically 15 degrees C above average winding rise. Refer to the “HS RISE ABOVE AVE WDG RISE” field in the Default Data Table, Appendix D.

Tested Top Oil Rise Over Ambient: Refer to the “TOP OIL RISE TEMP RUN 1” and “TOP OIL RISE TEMP RUN 2” fields in the Transformer Data Table, Appendix D.

Tested Bottom Oil Rise Over Ambient: Refer to the “BOTT OIL RISE TEMP RUN 1” and “BOTT OIL RISE TEMP RUN 2” fields in the Transformer Data Table, Appendix D. Reference “OA TO-BO”, “FA TO-BO”, and “FOA TO-BO” fields in Default Data Table, Appendix D.

Rated Page

This page allows for the entry of rated ambient and average winding rise data. Both of which should be available on the transformer test sheet(s).

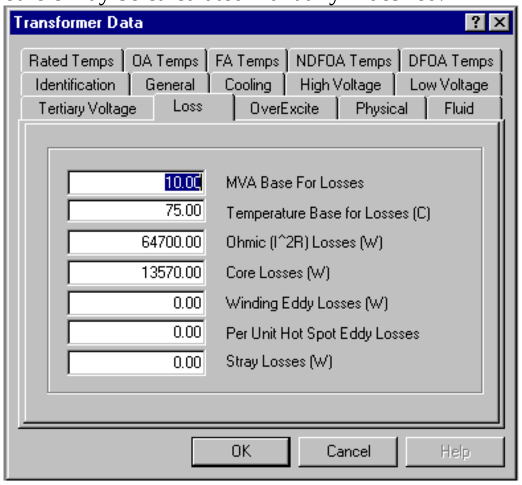


Rated Ambient: Refer to the "RATED AMBIENT" field in the Default Data Table, Appendix D.

Rated Average Winding Rise Over Ambient: Typically 55 or 65 degrees C. Refer to the "TEMP RISE" field in the Transformer Data Table, Appendix D.

Loss Page

This page allows for the entry of loss data. Some of these data are on the transformer test sheets. The others may be calculated manually if desired.



MVA Base for Losses: Usually the OA MVA rating except for FOA units. Refer to the “TEMP RUN 1 MVA LOAD” field in the Transformer Data Table, Appendix D.

Temperature Base for Losses: Refer to the “TEMP BASE FOR LOSSES” field in the Transformer Data Table, Appendix D.

Ohmic Losses (Load losses): Refer to the “COPPER LOSS TEST” field in the Transformer Data Table, Appendix D.

Core Losses (No-load losses): Refer to the “CORE LOSS TEST” field in the Transformer Data Table, Appendix D.

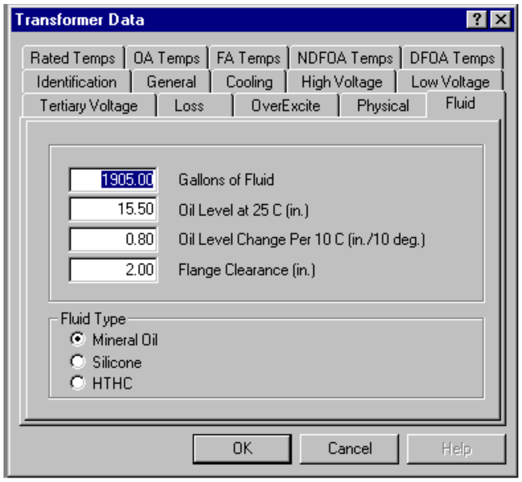
Winding Eddy Losses: Typically not known. Use of “0” is considered conservative. Refer to IEEE C57.91-1995 loading guide.

Per Unit Hot Spot Eddy Losses: Typically not known. Use of “0” is considered conservative. Refer to IEEE C57.91-1995 loading guide.

Eddy Losses: Typically not known. Use of “0” is considered conservative. Refer to IEEE C57.91-1995 loading guide.

Fluid Page

The data on this page is available on the transformer nameplate.



Gallons of Fluid: Refer to the "GALLONS OIL" field in the Transformer Data Table, Appendix D.

Oil Level at 25 Degree C: Refer to the "25C OIL LEVEL INCHES" field in the Transformer Data Table, Appendix D.

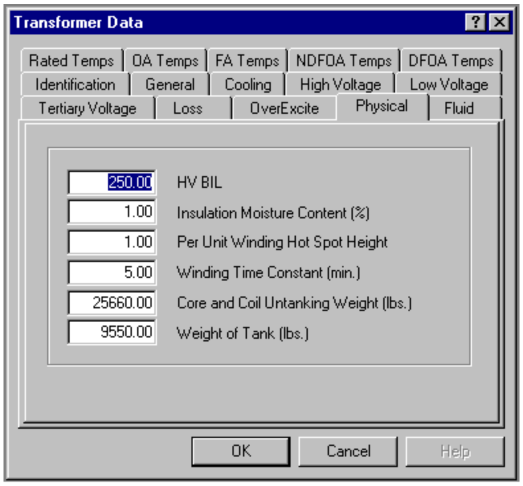
Oil Level Change per 10 Degrees C: Refer to the "LIQUID LEVEL CHG/10C" field in the Transformer Data Table, Appendix D.

Flange Clearance: Refer to the "FLANGE CLEARANCE" field in the Default Data Table, Appendix D.

Fluid Type: Model handles various fluid types. Consumers uses mineral oil type. Refer to the "FLUID TYPE" field in the Default Data Table, Appendix D.

Physical Page

Most of these data can be found on the transformer nameplate. The Loading Guide recommends data for the remaining parameters except for the insulation moisture content. The moisture content plays a role in the establishment of the default hot spot temperature constraint. High estimations of moisture content may result in conservative capability estimates.



Field Comments

HV BIL: Refer to the “HVBIL” field in the Transformer Data Table, Appendix D.

Insulation Moisture Content: Refer to the “PERCENT INS MOIST “ field in the Default Data Table, Appendix D.

Per Unit Winding Hot Spot Height: Typically unknown and therefore 1 used per IEEE Loading Guide. : Refer to the “PU HS HEIGHT “ field in the Default Data Table, Appendix D.

Winding Time Constant: Typically unknown and therefore 5 minutes is used per IEEE Loading Guide. Refer to the “WINDING TAU “ field in the Default Data Table, Appendix D.

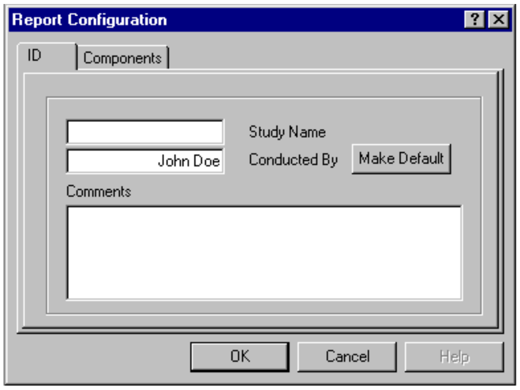
Core and Coil Untanking Weight: Refer to the “WEIGHT CORE & COILS” field in the Transformer Data Table, Appendix D.

Weight of Tank: Refer to the “WEIGHT CASE & ACCESS.” field in the Transformer Data Table, Appendix D.

Report Configuration Property Sheet

ID Page

This page allows the user to specify information that will clearly identify the report for future reference and interpretation.



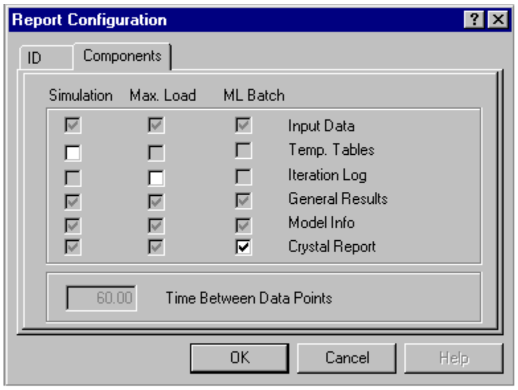
Study Name: For information only.

Conducted By: For information only.

Comments: For information only.

Components Page

TLC Reports have multiple sections. The Components Page allows the user some control over what components are included in the report and what aren't. For Simulations, full temperature tables may be included in the report. For Maximum Loading Studies, an iteration log can be included if so desired. However, in general, the optional components do not provide essential information and they require multiple pages.



Temperature Tables: Hourly temperature tables can be included in "Simulation" reports.

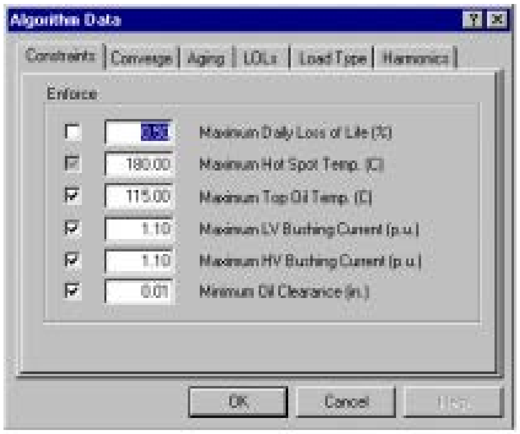
Iteration Log: For insight and/or troubleshooting, an iteration log can be included in Single Transformer Maximum Loading Reports. Inclusion of Iteration Logs will significantly increase the number of pages in the report.

Crystal Report: A "Crystal Reports" window is the standard way of reporting for Single Transformer Studies. However, for Multiple Transformer Studies, an "output" type text file is generated and placed in the "\out" subdirectory. The *out* type file was developed for importation into spreadsheets like Excel. The name of the report will be the name of the batch file with ".out" appended. Appendix C discusses the various file types that the program uses.

Algorithm Property Sheet

Constraints Page

The TLC Program can determine transformer capabilities while enforcing a variety of selectable constraints. In some cases, data may not exist to support a given constraint (e.g., oil expansion) and thus it would not be meaningful to constrain loading based on to it. Enforcing unsupported constraints can result in non-convergence; this condition will result in algorithm failure at which time the user will be notified appropriately.



Maximum Daily Loss of Life: Although an optional constraint, Consumers does not typically use DLOL as a constraint due to the overly conservative effects on capability results. There is also the matter of establishing what the constraint would be.

Maximum Hot Spot Temperature: When the Transformer Database is used as the source of transformer data, a hot spot limit is recommended according to logic set by Gary Schauffler. In batch mode the user never has a chance to change the recommendation, but in Single Transformer Maximum Loading mode the user may change the setting before running the study. Figure 5 illustrates the logic which recommends the hot spot limit.

Maximum Top Oil Temperature: Consumers uses 115 degrees as the maximum top oil allowed in any transformer. This number should never be raised.

Maximum HV Bushing Current: Typically, bushing ratings are allowed to be exceeded by 10%. However, *good* engineering judgement should always be used.

Maximum LV Bushing Current: Typically, bushing ratings are allowed to be exceeded by 10%. However, *good* engineering judgement should always be used.

Minimum Oil Clearance: Typically, a small number is used here. “0” would mean that the would be ready to spew forth.

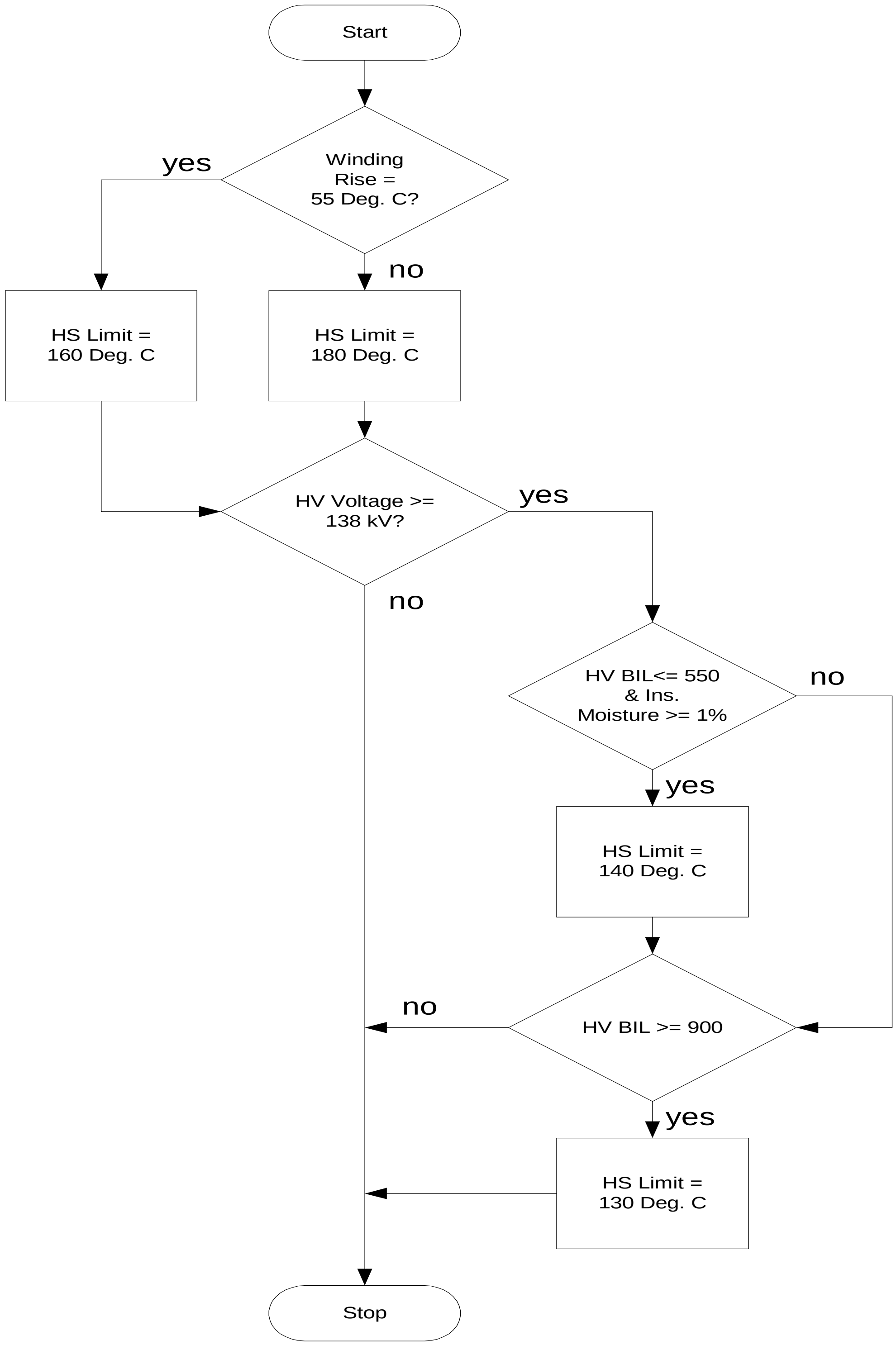
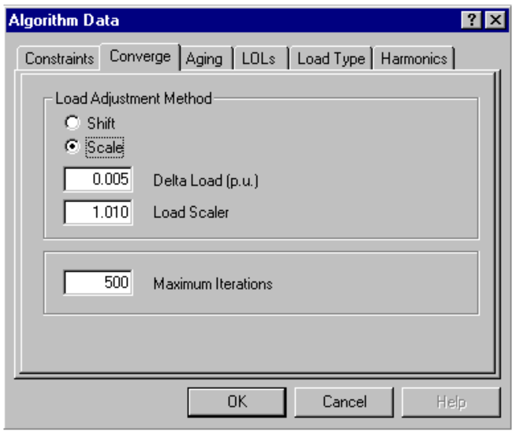


Figure 5. Logic for Hot Spot Limit Recommendation

Converge Page

When the Maximum Loading Algorithms attempt to locate the maximum load, they adjust the load profiles up and down. The amount and method by which the load is adjusted is set on the Converge Page. The load can be shifted up or down by a constant delta load, or it can be scaled up and down using a multiplier. The default is the scaler aproach which is the way the old program did it.

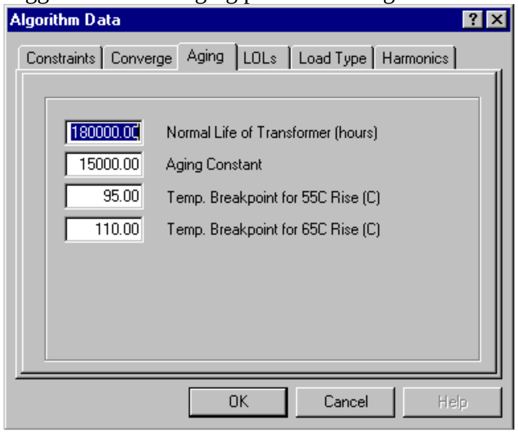


Load Adjustment Method: If “Shift” is selected, then the “Delta Load” parameter will be used as a constant to offset the load profile up or down as required to converge. However, if “Scale” is selected, then the “Load Scaler” will be used as a multiplier to increase or decrease the load. In either case, the harmonic multipliers also play a role in the final effect on the profile.

Maximum Iterations: This parameter serves as an escape hatch for internal looping in case the algorithm(s) is/are unable to converge. Some bad data cases will prevent convergence. For example, bad oil expansion data can lead to non-convergence.

Aging Page

The aging calculations defined in the loading guide are based on several empirical parameters. It is suggested that the aging portion of the guide be reviewed before significantly altering the aging constants.



Normal Life of Transformer: This is the expected life of a transformer in hours.

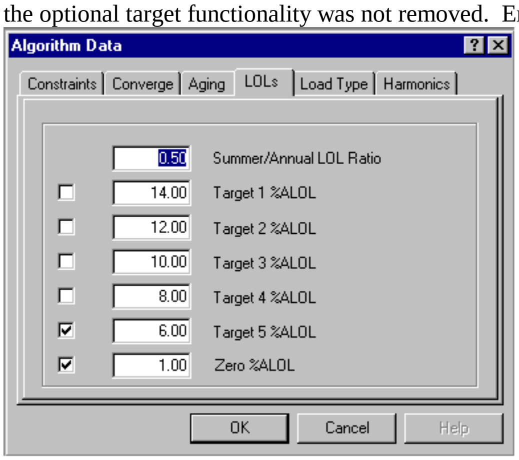
Aging Constant: Aging modeling is based upon laboratory determing degradation curves. The constant used is a function of the insulation parameter that is being modeled. Refer to the IEEE Loading Guide for more information.

Temperature Breakpoint for 55 Degree C Rise Transformer: Similar to "Aging Constant" parameter in that the data used is a function of the insulation parameter being modeled. Defaults for these aging parameters were established using the IEEE Loading Guide.

Temperature Breakpoint for 65 Degree C Rise Transformer: See above.

Loss of Life Target Page

The maximum loading type studies estimate several loading capabilities each given transformer. The program was expanded to handle several during the Asset Utilization Project. Although no longer needed the optional target functionality was not removed. Emergency Loading is always one of the targets.



Summer/Annual LOL Ratio: Establishes how the given Loss of Life targets are to be divided up as a function of the season.

ALOL Targets: Various targets are possible. Emergency, "6%", and "0%" are the only officially sanctioned targets.

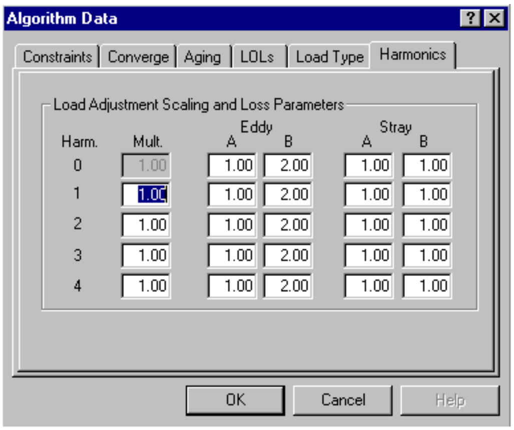
Load Type Page

The MLA employs load vs. temperature data when processing histogram data. The load vs. temperature data reduces the peak loading as a function of the average ambient temperature on an ambient profile basis. The effect is meant to evoke more realism in the SLOL aging calculations. Without a reduction of this kind, the algorithm would be applying the same worst case load profile across all of the respective histogram's ambient profiles. For more insight, refer to the example curves in Appendix B and the histogram file format in Appendix C.

Load Types: Four different load types are available. Each load type has a set of multipliers associated with it that are defined in the histogram files. These multipliers are used to reduce the load profile as a function of the average ambient temperature.

Harmonic Parameters Page

The core thermal algorithm is capable of modeling the effects of harmonic currents on transformer heating. However, non-fundamental modeling is still more or less a theoretical modeling capability of the algorithm. There has been no experimental confirmation of the accuracy of the algorithm when modeling harmonic loading. Because of this fact, the various coefficients and parameters involved in harmonic modeling have been made accessible to the user for adjustment. Overall, harmonic modeling remains an avante guard use of the program. A user who desires to model harmonic currents should review Fran Huguet’s report titled “A Computer Program for the Estimation of Liquid-Immersed Transformer Loading Capability.” This document discusses the issues and assumptions surrounding harmonic current modeling. Without a full understanding of the issues, it is recommended that the data on this page not be modified.



Harmonics: Up to five harmonics can be modeled (including the fundamental) by TLC. The orders and profiles of the harmonic loads are defined in the load profile data files. See Appendix C for details on load file formatting.

Multipliers: The multipliers control to what degree the “scaler” or “delta load” load adjustment parameters affect the load profile during convergence.

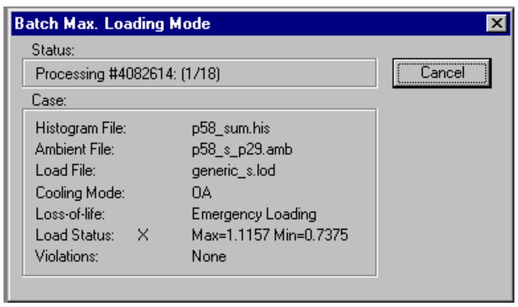
Coefficients and Exponents: The harmonic loss coefficients and exponents determine to what degree eddy current and stray losses are a function of each harmonic order that is being modeled.

Dialogs and Message Boxes

The TLC Program uses a variety of "dialogs" and "message boxes" to convey information to the user when appropriate. Some of these are not self-explanatory.

Running Dialog

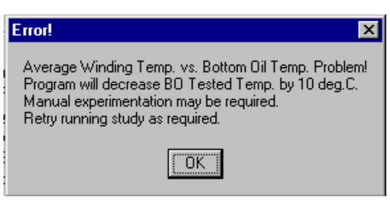
Once a study is executed, the TLC Program conveys the status of the study to the user via the "Running Dialog." The following image of the dialog was captured during a Multiple Transformer Maximum Loading Study.



The "Status" line indicates the serial number of the transformer currently being processed. It also indicates the given transformers position within the batch file as a measure of the study's progress. The "Case" information conveys the exact state of the algorithm at any given moment. The Loss-of-Life field indicates what target ALOL and SLOL are being processed. The accumulated SLOL is also posted. The Load Status data indicates the current minimum and maximum load in per unit form. The x, /, +, and - characters that intermittently appear show what adjustment method is being used and what direction the profile is being adjusted. Finally, the Violations field shows what constraints are violated at the given moment. Scrutiny of the Running Dialog during a study will provide additional confirmation of the algorithm flowcharts shown earlier.

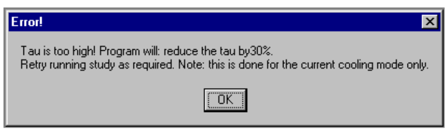
Temperature Relationship Issue Message Box

One of the benefits of the new thermal model is that it can model certain duct oil temperature phenomenon. To effectively do so, the model requires bottom oil heat run data. Unfortunately, bottom oil heat data was not included on older test sheets and so TLC is forced to estimate bottom oil test temperature in some cases. On occasion the estimate is inaccurate enough to result in a temperature relationship problem that the model can't handle. When doing single transformer studies, TLC will display the following message box and then automatically re-estimate the bottom oil temperature. The user should review the existing transformer data for errors and then try re-running the study. Usually, the problem will be resolved after one or two "adjustments." In some rare cases the transformer data may be so "strange" that it is difficult to proceed. In such cases, Gary Schauffler, Aaron Bomia, or Fran Huguet can be consulted.



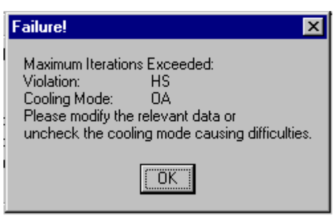
Winding Tau Problem Message Box

The core thermal algorithm of the program requires that the input data pass a complicated mathematically check to ensure that the algorithm remains stable. In previous versions of the program, the data would be iteratively adjusted to promote stability if required. After further research, the adjustment method has been changed so that only the assumed winding time constant is adjusted. The old method tweaked the time constant and some of the related test data. Because some of the test data had been estimated, the old method was plausible. However, for certain transformers multiple tweaks were required which resulted in test data being tweaked beyond reasonable amounts. Upon further review, it is more reasonable to adjust tau over a wider range than to adjust what could potentially be valid test data. The new method reduces the time constant by 30% each iteration. In Multiple Transformer Maximum Loading Mode the tau adjustment is done automatically up to 10 times. If the stability check isn't passed after 10 times something is assumed to be wrong with the input data and the transformer is rejected. In Single Transformer Maximum Loading Mode, the user is alerted to each adjustment with the following message.



Maximum Iteration Message Box

Bad or strange transformer data can sometimes prevent the maximum loading type studies from converging. In such cases, the first step is for the user to verify the transformer data. In some cases, the last violation will provide insight as to what data may be bad. Also, it is possible for the load adjustment parameters to be set too fine. In those cases, all may be well; it is just that the algorithm wasn't given long enough to converge. Increasing the maximum iteration count using the Algorithm Property Sheet may solve the problem. Finally, as is the case for all strange problems, Gary Schauffler, Aaron Bomia, or Fran Huguet may be contacted for assistance.



TLC Reports

The TLC Program relies on Crystal Reports to accomplish its reporting tasks. Crystal Reports (CR) is a canned software package that allows a programmer to invoke a report when desired in a standard window. First, a given study run populates several database tables. Next, CR is called and passed a formatted report file name. The report is then populated and presented to the user. This is noted because there are some features of the CR report window that are not 100% up to snuff and the programmer has no access to the CR code to fix these issues. For example, there are numerous export options available that do not all produce quality output. The best option for the report is to just print it and have the hardcopy. In the case of large batch studies, there is also the "output" file option discussed in Appendix C.

TLC reports are constructed from multiple components. Each of these components serves a unique purpose.

Report Components

Transformer and Algorithm Input Data

This section documents virtually all of the variables that are required by the study algorithms. It is included in every report.

Temperature Tables

Full hourly temperature tables can be included in a report if the user so desires. These tables document a variety of thermal data on an hourly basis. Temperature tables are only available for Simulations.

Iteration Log

Iteration logs can, at the user's option, be included in Maximum Loading Study reports. Although not essential, they can provide insight in cases where general results are inadequate.

General Results

The General Results component of a study documents the parameters that are of critical concern to a typical user. A General Results component is present in every report.

Model Information

The Model Information component of a report is meant to punctuate some of the key modeling considerations that should be remembered when interpreting data. The guide requires citing of the IEEE Loading guide as the source for the thermal algorithm.

Report Examples

Understanding a TLC report is not always the simplest task. There are a variety of model options and tracking these options can appear cryptic at times. To assist the user in reading reports, a few TLC Reports have been included in Appendix G.

Appendices

Appendix A: Ambient Statistical Data

Methodology for the Creation of Ambient Histograms

The ability of a transformer to rid itself of excess heat is dependent on the ambient environmental conditions at the substation site. Unfortunately we do not have hourly ambient temperature readings in the substations to correlate with the hourly load readings from SCADA and other sources. However, there are hourly temperature readings at approximately two dozen National Weather Service (NWS) weather observation stations located at various places throughout the Lower Peninsula of Michigan. The data collected from these stations are processed to form hourly ambient temperature profiles. Each substation is then associated with it's nearest NWS station.

The process of creating temperature profiles begins by reading hourly observations at each weather station from 1994 to 1998. The readings are then subdivided into two 'peak' and 'off-peak' periods. The first period begins June 1 and ends August 31, which corresponds to the time of year when temperatures and loads are expected to be at their highest. The second 'off-peak' period includes data for the other nine months of the calendar year.

After grouping within the peak and off-peak periods, a daily average temperature is calculated for each day. Days with the same average temperature are combined, hour by hour, to create an average hourly temperature profile for all days having that particular daily average temperature. For example, the first row of the table below shows that there were two days during the peak periods from 1994 to 1998 with a daily average temperature of 8 degrees. The hourly temperatures for each of these two days are averaged together for each of the 24 hours in the day (e.g. at hour 9 two readings of 13 and 9 degrees are averaged together to produce 11 degrees).

SUMMER PROFILE (June 1 - August 31)
STATION[0] APN (Alpena) 5 years reporting — Temperatures in degrees C.

Ave Tmp	Num Days	Min Tmp	Max Tmp	Average-Hourly-Temperature 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
8	**2**	1	14	4	3	2	2	2	2	5	8	10	**11**	12	13	12	12	14	12	12	12	11	**10**	9	8	7	7
9	**1**	5	13	5	5	6	6	6	6	7	9	11	10	11	12	12	12	13	12	12	11	11	**9**	8	7	7	7
10	**3**	3	16	7	7	7	7	7	7	9	10	11	12	12	12	13	13	13	13	14	13	12	**11**	9	7	6	6
11	**7**	1	19	8	7	6	5	5	7	9	11	13	14	15	15	15	15	15	15	15	14	13	**12**	9	7	7	6
12	5	-1	19	8	8	8	8	8	9	10	11	13	14	15	15	16	15	15	15	15	14	14	14	13	12	12	12
13	11	2	23	8	8	7	7	7	8	10	13	16	17	17	17	18	18	18	17	17	16	15	13	12	11	10	10
14	25	4	25	11	10	10	10	10	10	12	14	15	17	17	18	18	18	18	18	18	17	16	14	13	13	12	11
15	38	6	26	12	12	12	12	11	12	13	15	16	17	18	19	19	19	19	19	18	18	17	15	13	12	12	11
16	32	3	27	12	12	11	11	10	11	13	15	18	19	20	20	21	21	21	21	21	20	19	17	15	14	13	12
	?							?								?							?				
27	4	14	34	21	21	21	21	21	22	24	27	29	30	32	32	33	33	33	33	32	31	28	25	24	23	22	22
29	1	19	38	21	22	21	19	21	22	24	27	30	32	34	37	37	38	38	38	38	36	33	30	27	25	23	22

A file is created for each average temperature for each of the two annual periods for each of the two dozen NWS observation stations. This results in a lot of files, which creates data maintenance problems and slows simulation times. We also found that generating too fine a data set tends to produce misleading results. For example, the model might zero in on a single 29 degree average day while ignoring a week's worth of 28 degree days in which a loss of life might also be incurred. For this reason the individual degree profiles are rolled up into aggregate profiles typically covering four degrees. This gives a good balance of the number of files to produce and maintain, simulation runtimes, and accuracy of the results.

Ambient Statistical Data

The process of aggregating the daily readings begins with the data shown in the table above. Several average temperatures are combined by adding in the average temperature for each hour weighted by the number of days spent at that temperature. For example, to combine the 8-11 degree days into a single aggregate profile, the average temperature for hour 19 would be calculated as

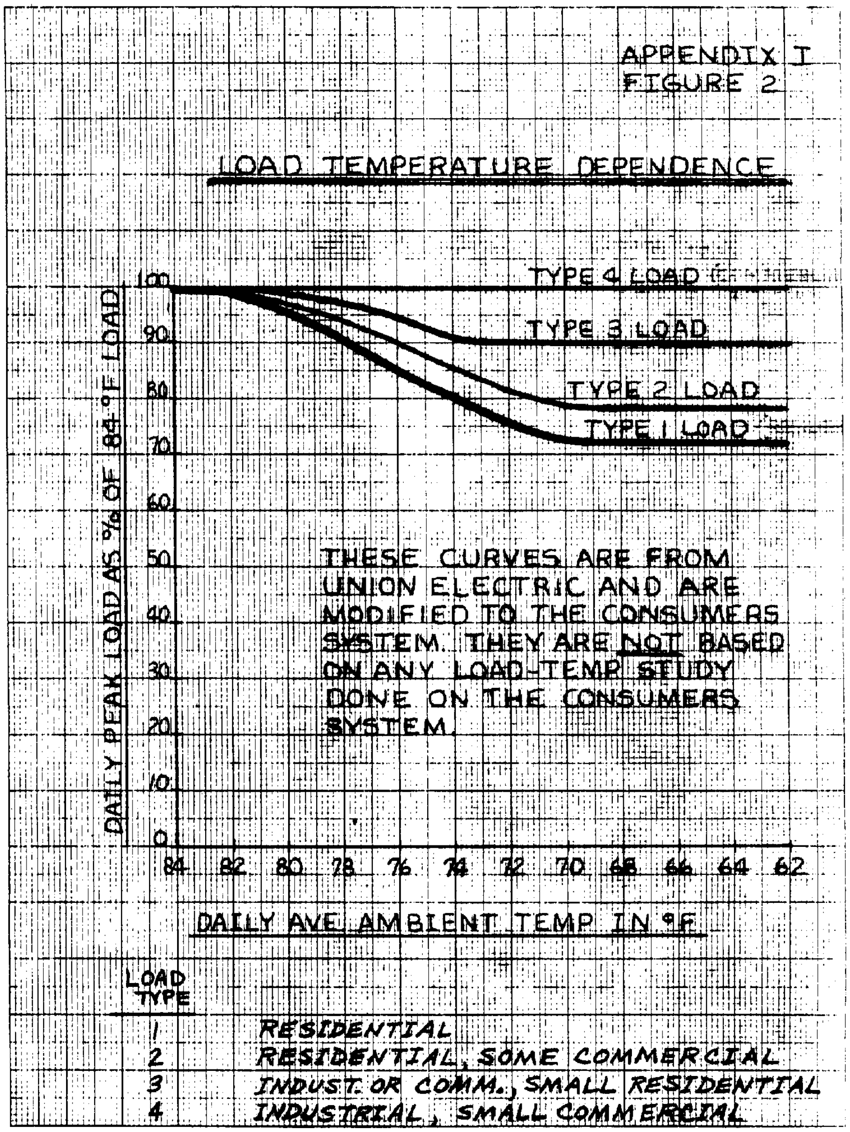
$$(10_{deg})(2_{days}) + (9_{deg})(1_{day}) + (11_{deg})(3_{days}) + (12_{deg})(7_{days}) / (2+1+3+7_{days}) = 11_{deg}.$$

The table below shows how the daily average profiles are combined into six or eight aggregate bins, depending on the season.

Aggregate Bin, Peak	9	13	17	21	25	29		
Daily Average Temperature Range	– 10.99	11.00 – 14.99	15.00 – 18.99	19.00 – 22.99	23.00 – 26.99	27.00+		
Aggregate Bin, Off Peak	-8	-2	2	6	10	14	18	22
Daily Average Temperature Range	– -4.01	-4.00 – -0.01	0.00 – 4.99	4.00 – 7.99	08.00 – 11.99	12.00 – 15.99	16.00 – 19.99	20.00+

Appendix B: Peak Loading Vs. Ambient Temperature

The following graph documents Consumers Energy's historical understanding, for capability purposes, of the relationship between daily average ambient temperature and peak load as a function of load type. Modern curves, similar in shape to these, have been generated by Karl Grieve based on his massive number crunching efforts. The overall phenomenon is reflected in TLC capabilities through the use of the load multipliers in the histogram files (see Appendix C).



Appendix C: Data File Formats

The TLC Program requires a variety of supporting data files. In most cases, these files are generated by another program (Karl's). However, if the user desires to manually create these file it should be noted that the program provides little or no file format checking and as a consequence is highly susceptible to data file format error. Therefore, the user should strictly adhere to file formatting guidelines. There is also a predetermined, "hardwired," directory structure in place that governs where the data files must exist.

Directory Structure

To reduce coding requirements and to keep the data files organized, a hardwired (i.e., inflexible) directory structure has been implemented as part of the program. Figure 1 shows the structure. Figure 2 illustrates the data flow patterns among the different TLC files and components. Each unique TLC file type has a directory and an extension associated with it. The program will search for a given file type in the associated directory (and only there). Misplacing files will generally be harmless, but it will definitely be unproductive. In some critical cases, the program will warn you if an expected file doesn't exist where it should and then it will terminate in an abrupt (yet stable) manner. The Setup program will install the TLC files under the standard "Program Files" directory wherever it may be (C, D, or otherwise) on the user's local hard drive. Note: TLC has proven to be too file intensive to be run from the network.

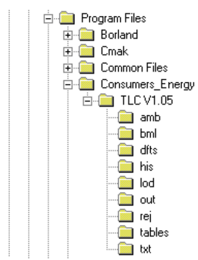


Figure 1. TLC Directory Structure

Directory Associations

Directory	**Contents**
Consumers_Energy	Consumers owns TLC in all aspects. We can install as many copies as we desire. However, the fewer copies the better.
TLC V1.05	Each version of TLC installed on a computer will have its own directory tree. This directory contains the TLC executable file (tlc.exe), help files, and other misc. files required by the exe file.
amb	Ambient Profile Files (*.amb) - user modifiable files
bml	Batch Max Load Files (*.bml) - user modifiable files
dfts	Default Data Files (*.dft) - files should not be modified
his	Ambient Histogram Files (*.his) - user modifiable files
lod	Load Profile Files (*.lod) - user modifiable files
out	Batch Max Output Files (*.out) - program generated files
rej	Batch Max Reject Files (*.rej) - program generated files
tables	Paradox Database Tables (*.db) - some modifiable, some program generated
txt	Text files (*.txt) - misc. information files

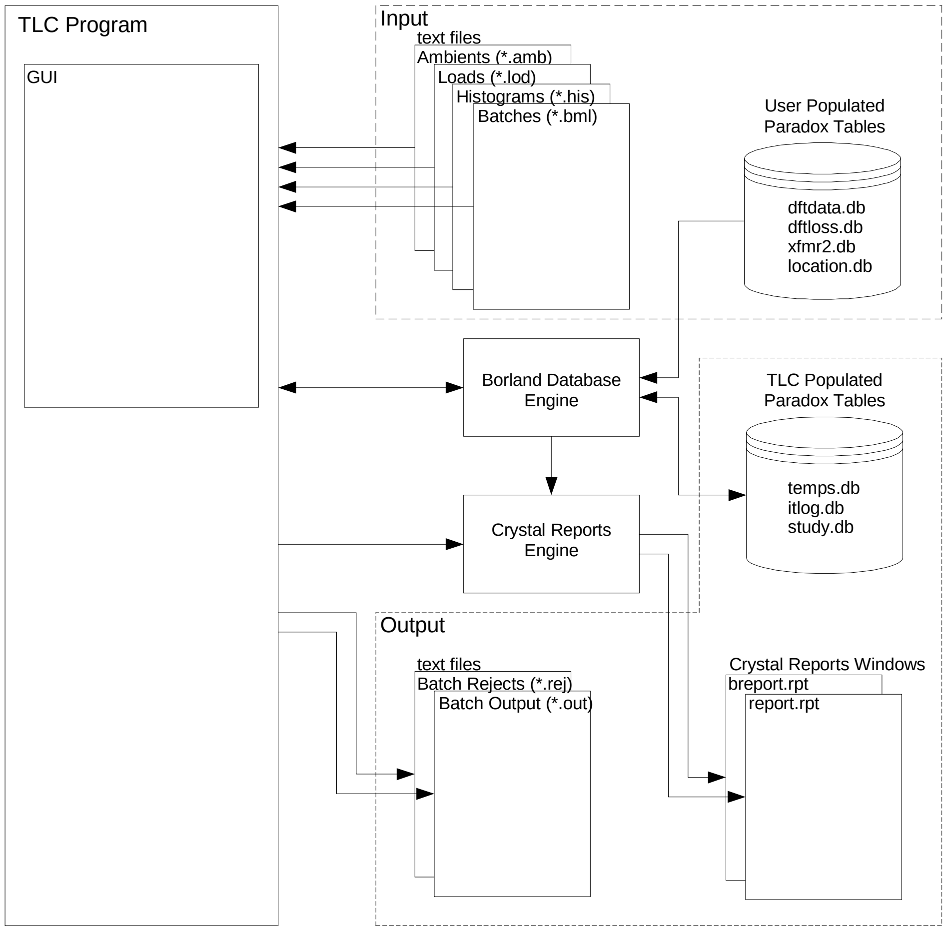


Figure 2. TLC Data Flow Diagram

Load Profiles

Comment lines are optional within a load profile file. Comment lines are placed in the began of the file. A comment line is indicated by a "#" character in the first column of the line. Comment lines are used to describe data specifications. After all comment lines, the load profile begins with the KVA base of the load data. The KVA base as well as all of the data in the load profile is entered in per unit form. If this is entered as 0 (required for Max. Loading Studies), then the base will be the rating of the current cooling mode to be modeled. However, if an absolute profile is desired, then the appropriate non-zero KVA base should be entered. The next line of the file contains the harmonic index data, e.g., 1.0 is the fundamental harmonic. The harmonic index is entered in decimal format (as opposed to integer format) because the current model can be used to model interharmonics (e.g., 3.12). If more than 1 harmonic (up to 5) is to be modeled, then the indices should be separated by one space each. The remainder of the file's lines are all formatted identically. They consist of a time ordinate (in hours), a space, and a harmonic load ordinate, a space, another harmonic load ordinate (if appropriate), and so on. The data coordinates need not be equidistant in time. Also, TLC profiles can be encoded by up to 50 coordinates.

For a specific load profile, a user may also dumb SCADA data into a TLC formatted file from the intranet.

Whenever a user employs a synthetic load profile, the program generates a standard formatted load profile data file that will represent the synthetic load. The program uses the "xxinit.lod" and "xxtarget.lod" files for this purpose. Do not delete them. Also, the user should not use these filenames as these files are routinely rewritten. One other comment, which goes for all user created TLC data files,... do not insert a carriage return after the last piece of data. This would insert an empty line. Backspace if you went to far until the cursor follows the last character of the data and then save the file to the appropriate directory with the appropriate extension. The extension filter will add the correct filter if it is selected.

Example 1. illustrates the appropriate format for a single harmonic load profile data file. Note that a valid load profile includes a beginning coordinate at time 0.0 and ends with a coordinate at time 24.0. Also, remember that the points defining both load and ambient profiles need not be time equidistant. The number of segments determines how coarse or fine the approximation is.

fundload
```
10000
1.0
0 0.73
10 0.88
13 1.03
14 1.07
15 1.10
16 1.10
18 1.04
21 0.88
24 0.73
```

Example 1. Fundamental Load File

Example 2. illustrates the appropriate format for a multi-harmonic load profile data file.

HarmExample
```
0.0
1.00 3.00 5.00
0 0.85 0.05 0.01
1 0.85 0.10 0.02
2 0.85 0.10 0.03
22 1.00 0.10 0.03
23 0.85 0.10 0.02
24 0.85 0.05 0.01
```

Example 2. Multi-Harmonic Load File

Example 3 shows an example of a load file generated by TLC for a Synthetic Profile. Note how there is a duplication of time ordinates to accomplish the step nature of the profile.

```
s_target
0
1.0
0.0 0.85
6.00 0.85
6.00 1.00
18 1.00
18 0.85
24.0 0.85
```

Example 3. TLC Generated Synthetic Load File

Ambient Profiles

Ambient profiles are defined by piecewise linear segments. An ambient data file contains data coordinates that define the endpoints of the segments. A data file line begins with a time ordinate in hours, followed by a space, then by the ambient temperature ordinate in degrees C. Up to 50 coordinates can be used to define an ambient profile. The coordinates need not be time equidistant, but must be increasing in time.

Example 4. illustrates a portion of a typical ambient profile data file. Note that a valid ambient profile should begin with a coordinate at time 0.0 and ends with a coordinate at time 24.0.

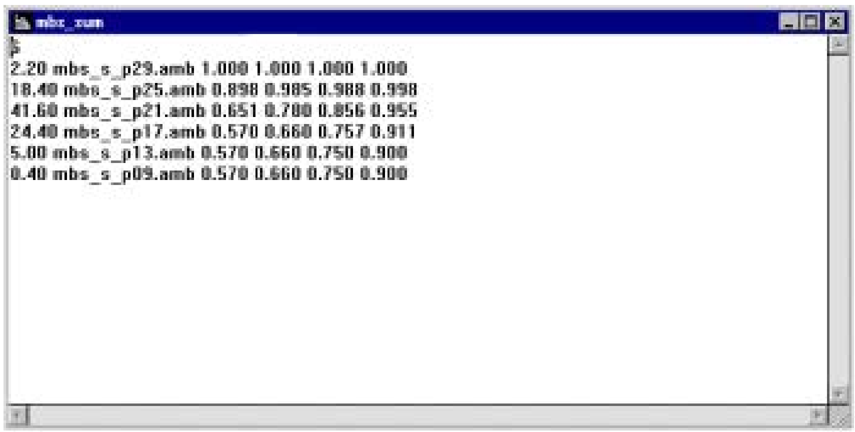
```
apn_x_p29
0.0 21.1
1.0 21.7
2.0 21.1
3.0 18.9
4.0 20.6
5.0 21.7
6.0 24.4
7.0 26.7
8.0 30.0
9.0 32.2
10.0 34.4
11.0 36.7
12.0 37.2
13.0 38.3
14.0 38.3
15.0 38.3
16.0 37.8
```

Example 4. Typical Ambient Profile

Ambient Histograms

Ambient histogram files are employed by the Maximum Loading Algorithm to calculate seasonal aging. The first line of a histogram file denotes the number of bins, N, in the histogram. N lines must then follow, each defining a bin of the histogram. A bin line starts with the frequency of the ambient occurrence (per this season) followed by: a space, the ambient filename (no path), a space, the residential load type multiplier, a space, the residential/some commercial multiplier, a space, the industrial/commercial/small residential multiplier, a space, and then the industrial/small commercial multiplier. Strict adherence to this format is required. Appendices A and B discuss the origins of the data used to construct the standard histogram files currently in use.

Example 5 shows an example of a properly formatted histogram file.



```
6
2.20 mbs_s_p29.amb 1.000 1.000 1.000 1.000
18.40 mbs_s_p25.amb 0.898 0.985 0.988 0.998
41.60 mbs_s_p21.amb 0.651 0.700 0.856 0.955
24.40 mbs_s_p17.amb 0.570 0.660 0.757 0.911
5.00 mbs_s_p13.amb 0.570 0.660 0.750 0.900
0.40 mbs_s_p09.amb 0.570 0.660 0.750 0.900
```

Example 5. Ambient Histogram

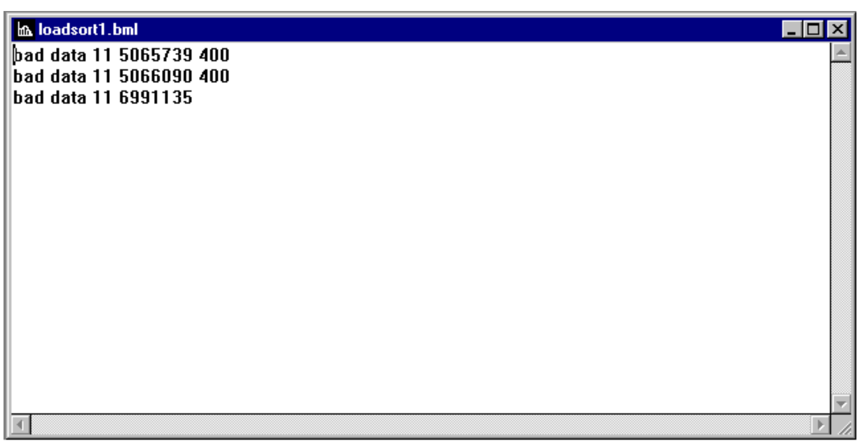
Transformer Batch Files

Multiple Transformer Maximum Loading Studies use transformer "batch max load" files (*.bml) as input. Each line, starting with the first should have one transformer serial number on it. Care should be taken not to insert additional spaces after data, or a line after the last serial number. The program will process the serial numbers in the order they appear. There can be anywhere for 1 to 400 units in a batch. Beyond or even close to 400 unit batches send TLC into crawl mode. Example 6 illustrates a typical batch file. Batch files must be saved in the "bml" directory.

Example 6. Transformer Batch File (*.bml) Example

Batch Reject Files

A "batch reject" file is created for every batch that is studied. Any transformer that the program couldn't fully process will be logged here with an error code of some sort. The algorithm rejects a transformer as soon as it can and so the error code that is seen in the reject file represents only the first error encountered. There could be many more. It is best to fully review the associated record in the transformer table before proceeding. Example 7 illustrates a typical reject file. Reject files are found in the "rej" subdirectory and have a ".rej" appended to the batch file name that was processed.



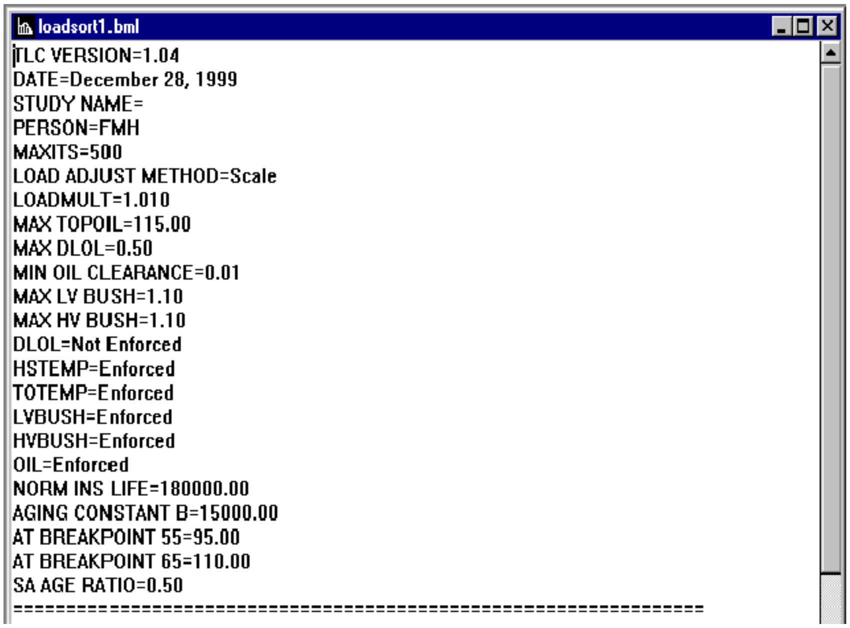
Example 7. Transformer Batch Reject File (*.rej) Example

The following list documents the various error codes and where a user should start looking. In single transformer studies, many of these errors will simply appear in message boxes rather than a batch reject file.

Error Codes	*Comments*
1 MVA Loss Base	TEMPRUN 1 MVA LOAD, TEMPRUN 2 MVA LOAD, or TOP OIL TEMP RUN 1
2 OA MVA load base	MVA RATING HV WDG and COOLING
3 FA MVA load base	MVA RATING HV WDG and COOLING
4 NDFOA/FOA MVA load base	MVA RATING HV WDG and COOLING
5 DFOA MVA load base	MVA RATING HV WDG and COOLING
6 No cooling modes selected	probably missing test run data
7 Ave winding temp>=hot spot temp	HV WDG RISE 1 or LV WDG RISE 1 or same for run 2
8 Bottom oil temp >=top oil temp	BOTTOM OIL RISE TEMP 1 or 2
9 Bottom oil temp>=ave winding temp	BOTTOM OIL RISE TEMP 1 or 2 and/or HV WDG RISE 1...
10 Bad winding data	TRF WINDING TYPE must be "AUTO", "2 WINDER", or "3 WINDER" only
11 Bad voltage data	SUB HV PH-PH KV or SUB LV PH-PH KV
12 Bad rated ambient rise	TEMP RISE
13 Bad loss temp base	TEMP BASE FOR LOSSES
14 Bad test temp data	ALL TEMP RUN DATA
15 Bad loss data	CORE LOSSES ("no-load losses") or COPPER LOSSES ("load losses")
16 Bad weight data	
17 Bad fluid gallons data	
18 Bad fluid type	
19 Ave. winding temperature vs. bottom oil temperature problem	Complicated issue
20 Winding tau problem, tweaking failed to solve	Complicated issue
21 MVA ratings or cooling modes	MVA RATING HV WDG and COOLING
22 MVA ratings or cooling modes	MVA RATING HV WDG and COOLING
23 Physical violation detected when not processing worst ambient.	Should not happen if histogram file constructed properly. Complicated issue.
31 Unable to open load file	Location table has bad .lod file data or .lod file missing
32 Unable to open ambient file	Location table has bad .amb file data in .his file or .amb file missing

Batch Output Files

A Multiple Transformer Maximum Loading Study generates a standard Crystal Reports report, but it also generates a text “out” file. The out file was designed to be imported into a spreadsheet. It is not as verbose as the CR report, but is does open up possibilities for mass data review. Example 8 reveals a portion of a typical batch output file. Output files are located in the out directory and have an “.out” appended to the associated batch filename.



```
loadsort1.bml
TLC VERSION=1.04
DATE=December 28, 1999
STUDY NAME=
PERSON=FMH
MAXITS=500
LOAD ADJUST METHOD=Scale
LOADMULT=1.010
MAX TOPOIL=115.00
MAX DLOL=0.50
MIN OIL CLEARANCE=0.01
MAX LV BUSH=1.10
MAX HV BUSH=1.10
DLOL=Not Enforced
HSTEMP=Enforced
TOTEMP=Enforced
LVBUSH=Enforced
HVBUSH=Enforced
OIL=Enforced
NORM INS LIFE=180000.00
AGING CONSTANT B=15000.00
AT BREAKPOINT 55=95.00
AT BREAKPOINT 65=110.00
SA AGE RATIO=0.50
=================================================================
```

Example 8. Transformer Batch Output File (*.out) Example

Appendix D: Database Tables

The TLC Program relies on a variety of database tables. These tables are currently in Paradox form. They are located in the "\tables\ " subdirectory. Only four of these tables will ever require data editing by the user. The four tables are: the Transformer Data Table, the Location Data Table, the Default Data Table and the Default Loss Table. The first of these, typically named "Xfmrdat2.DB", is formed from a query on SDS's Major Equipment Database (MED). Editing it locally may help a user avoid manual entry in the short run, but periodic file pumping/updates will overwrite the file and all edits will be lost. Permanent transformer data edits must be done to the MED. The second table is the "Location.DB" table. It defines the load profiles, histograms, and load types associated with a given substation (delineated by WD and bank number). This table will also be periodically updated and originates in SDS, but the data will be supplied by either Karl Grieve or his replacement. The third and fourth tables contain default data. They have been populated according to the officially sanctioned approaches that are in place for capability studies. They should not require frequent modification.

Transformer Data Table

The Transformer Data Table (defined below) is keyed on serial number. There are strict rules concerning data entry. Violation of these rules will most like result in the transformer being rejected. In worst cases, the program will terminate.

Field Name	Field Type	Comments
SERIAL NUMBER	A27 (key)	required-not case sensitive
ITEM NUMBER	A7	optional-for information only
STATION 1	A20	optional-for information only
WD	N	required-used to query Location Table
BANK NUMBER	A4	required-used to query Location Table
MANUFACTURER	A20	optional-for information only
MVA RATING HV WDG	A11	required[1]
MVA RATING LV WDG	A11	optional-usually same as for HV
MVA RATING TV WDG	A11	optional-usually same as for HV
COOLING	A12	required[1]
TEMP RISE	A4	required
HVBIL	A4	optional-plays a role in temperature limits
PH	N	required[2]
TRF WINDING TYPE	A8	required[3]
CORE LOSS TEST	N	required
COPPER LOSS TEST	N	required
WEIGHT CORE & COILS	N	required
WEIGHT CASE & ACCESS.	N	required
GALLONS OIL	N	required
BUSHING AMPS HV	N	required
BUSHING AMPS LV	N	required
25C OIL LEVEL INCHES	N	optional[4]
LIQUID LEVEL CHG/10C	N	optional[4]
TEMPRUN 1 MVA LOAD	N	required[5]
TEMPRUN 2 MVA LOAD	N	optional[5]
TOP OIL RISE TEMP RUN 1	N	required[5]
TOP OIL RISE TEMP RUN2	N	optional[5]
BOTT OIL RISE TEMP RUN 1	N	required[5]
BOTT OIL RISE TEMP RUN 2	N	optional[5]
HV WDG RISE RUN 1	N	required[5]
HV WDG RISE RUN 2	N	optional[5]
LV WDG RISE RUN 1	N	required[5]

LV WDG RISE RUN 2	N	optional[5]
TV WDG RISE RUN 1	N	required[5]
TV WDG RISE RUN 2	N	optional[5]
LTC TYPE	A20	optional-for information only
SUB HV PH-PH KV	N	required
SUBHVCON	A5	required[6]
SUB LV PH-PH KV	N	required
SUBLVCON	A5	required[6]

Notes:

1. The number of ratings must agree with the number of cooling modes. For example, if a transformer is OA/FA rated it has to have an MVA rating of the form A/B. A second example would be OA/FA/FA,... the rating data must have the form A/B/C. If it has anything else, the transformer record will be rejected. In extreme cases the program may not behave predictably. Also, there are only five valid cooling designations: OA, FA, FFA, FOA, and DFOA. They must be upper case.

2. There are only two valid entries possible for the "PH" field: 1, and 3. One signifies that the transformer is a single-phase unit. Three signifies that it is a three-phase unit. This is critical information for the bushing current calculations.

3. There are only three valid entries possible for the "TRF WINDING TYPE" field: AUTO, 2 WINDER, and 3 WINDER. These must be upper case.

4. If oil level data is available it should be entered. However, if it is not available, but you have actually looked through all available drawings, then "0"s should be entered for the oil data fields. If data is not immediately available and you haven't looked, then the oil data fields should be left empty (NULL). Errors in this field typically result in the maximum iteration count being exceeded due to lack of convergence.

5. A valid transformer data record will always have at least one set of test temperature data (typically OA except for some FOA units). The lowest rating test data must be located in the "TEMP RUN 1" data fields. If the test sheet had a second heat run then that data should be entered in the "TEMP RUN 2" data fields. Note that if a transformer is rated "purely" FOA, TLC requires the heat run data be entered in the "TEMP RUN 2" fields; otherwise, TLC will fail prior to running the desired study. Test temperatures will be estimated for any cooling mode for which it data is not specified by the TEMP RUN 1or 2 fields. Another rule that should be followed is that the highest rating test data, if available, should be used for TEMP RUN 2 data. For example, consider a OA/FA/FA rated unit with three sets of heat run data on the test sheet. The OA temperature data would be entered in the TEMP RUN 1 fields, and the second FA temperature data, the higher of the two, would be recorded in the TEMP RUN 2 field. Finally, the bottom oil temperature historically has not been included on the test sheets. If it was not and can not be determined from the manufacturer, then the bottom oil heat run fields should be left blank. This will signal the program to estimate the bottom oil temp based on Maria Pedula's findings. All new transformers should have this data on the test sheets.

6. There are only two valid entries possible for the connection fields: Y, and DELTA. Any other entry will lead to transformer rejection (or worse).

Location Data Table

The Location Table (Location.DB) can be edited by the local user, but once again file updates/pumping will write over any local user changes so edits are not recommended. If unique scenarios are desired, the Single Transformer Maximum Loading Mode offers all of the options that are possible with the program. The master location table originates in SDS, but it will be periodically updated by SDS, SO, and/or TPP based on SCADA/estimator/max load data. Currently, if loading data is not known for a given location, generic system loading profiles are used. The histogram (ambient) data is generally known based on the nearest airport ambient data. If you are aware of localized weather phenomena that aren't reflected in the airport data and you can construct properly formatted histogram and ambient files, let SDS know and these files can be included with all of the others. Also, the master location table can be edited accordingly.

Field Name	Type	Comments
WD	N(key)	required
BANK NUM	A5(key)	required[1]
LOAD TYPE	A6	required[2]
SUMMER LOAD	A33	required[3]
WINTER LOAD	A33	required[3]
SUMMER HIS	A33	required[3]
WINTER HIS	A33	required[3]

Notes:

1. This field should follow the WD bank number naming conventions.

2. There are only four possible valid entries for the LOAD TYPE field: 1,2,3 and 4.
   1=residential
   2=residential, small commercial
   3=industrial or commercial, small residential
   4=industrial, small commercial

   The corresponding load multipliers are located in the relevant histogram file. See Appendix D for more details on load multipliers.

3. The files specified here must be present in the appropriate directories and must also be formatted correctly.

Default Data Table

As part of a general programming approach, virtually all variable defaults are not hardwired in the code. Rather, they originate in the Default Data Table. The following is a list of the default data fields with commentary when necessary.

Field Name	Type	Comment
DEFAULT DATA INDEX	A30(key)	do not modify
KVA BASE FOR LOSSES	N	
KVA BASE FOR LOAD	N	
TEMP BASE FOR LOSSES	N	
RATED AVE WDG RISE	N	
TESTED TO RISE OVER AMB	N	
TESTED BO RISE OVER AMB	N	
TESTED AVE WDG RISE	N	
HS RISE ABOVE AVE WDG RISE	N	
RATED AMBIENT	N	
STAGE 1 CONV FACTOR	N	do not modify
STAGE 2 CONV DELTA LOAD	N	do not modify
DELTA PRINT	N	do not modify
SUB HV KV	N	
SUB LV KV	N	
SUB TV KV	N	
HV BUSHING AMPS	N	
LV BUSHING AMPS	N	
TV BUSHING AMBS	N	
AGING TEMP BRKPT 55C	N	from C57.91
AGING TEMP BRKPT 65C	N	from C57.91
FLUID TYPE	S	
SUM/ANN LOL RATIO	N	per AU
WINDING TAU	N	from C57.91
PU HS HEIGHT	N	from C57.91
MAX ITS	S	
MAX HS TEMP	N	
MAX TO TEMP	N	
MAX DLOL	N	
EMERGENCY LOL	N	
ZERO LOL	N	
PU LV MAX BUSH A	N	
PU HV MAX BUSH A	N	
MIN OIL CLEAR IN	N	
CONSTRAIN HS TEMP	L	true=enforce HS
CONSTRAIN TO TEMP	L	true=enforce TO
CONSTRAIN LV BUSH A	L	true=enforce LV amps
CONSTRAIN HV BUSH A	L	true=enforce HV amps
CONSTRAIN OIL EXP	L	true=enforce oil clearance
CONSTRAIN DLOL	L	true=enforce DLOL
CONSTRAIN ALOL	L	true=enforce ALOL
OA STUDY	L	
FA STUDY	L	
NDFOA STUDY	L	
DFOA STUDY	L	
AVAIL COOLING	A30	
MVA RATING HV WDG	A30	
MVA RATING LV WDG	A30	
MVA RATING TV WDG	A30	

STUDY NAME	A30	
PERSON	A30	
COMMENTS	M	
PHASE	S	
PERCENT INS MOIST	N	
AGING CONST B	N	
NORM INS LIFE HRS	N	
INIT SYNTH KVABASE	N	
INIT PRELOAD	N	
INIT PEAK	N	
INIT DUR	N	
INIT START	N	
SYNTH KVABASE	N	
TARGET PRELOAD	N	
TARGET PEAK	N	
TARGET DUR	N	
TARGET START	N	
SERIAL NUMBER	A30	
INIT HS TEMP	N	
INIT W TEMP	N	
INTI TO TEMP	N	
INTI DO TEMP	N	
INIT BO TEMP	N	
TEMP TABLE S	L	
IT LOG ML	L	
CR BML	L	
LOAD TYPE	S	
COND MAT	S	
FLANGE CLEARANCE	N	
LOAD ADJUST METHOD	S	
LOAD MULT	N	
T1 LOL	N	
T2 LOL	N	
T3 LOL	N	
T4 LOL	N	
T5 LOL	N	
TZ LOL	N	
T1 LOL CB	L	true=enforce target lol #1: checkbox
T2 LOL CB	L	true=enforce target lol #2: checkbox
T3 LOL CB	L	true=enforce target lol #3: checkbox
T4 LOL CB	L	true=enforce target lol #4: checkbox
T5 LOL CB	L	true=enforce target lol #5: checkbox
TZ LOL CB	L	true=enforce zero lol : checkbox
OA TO-BO	N	temperature differential
FA TO-BO	N	temperature differential
FOA TO-BO	N	temperature differential

Harmonic Data Table

Because of the sensitive nature of the harmonic parameter, they were kept separate from the other default data parameters. As noted in the body of the document, the harmonic loss parameters should not be adjusted without a full understanding of all of the issues involved with harmonic modeling.

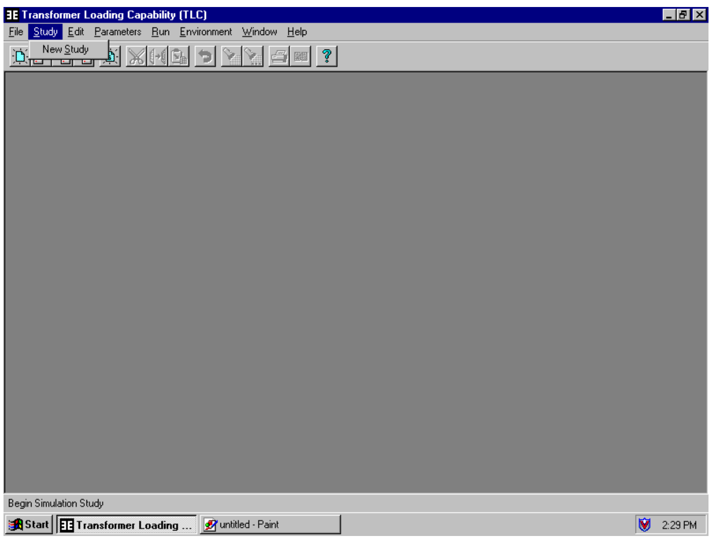
Field Name	Type	Comment
NAME OF DEFAULTS	A30(KEY)	
HARM TWEAKER 0	N	
HARM TWEAKER 1	N	
HARM TWEAKER 2	N	
HARM TWEAKER 3	N	
HARM TWEAKER 4	N	
MIN LOAD 0	N	
MIN LOAD 1	N	
MIN LOAD 2	N	
MIN LOAD 3	N	
MIN LOAD 4	N	
EDDY COEF 0	N	
EDDY COEF 1	N	
EDDY COEF 2	N	
EDDY COEF 3	N	
EDDY COEF 4	N	
EDDY EXP 0	N	
EDDY EXP 1	N	
EDDY EXP 2	N	
EDDY EXP 3	N	
EDDY EXP 4	N	
STRAY COEF 0	N	
STRAY COEF 1	N	
STRAY COEF 2	N	
STRAY COEF 3	N	
STRAY COEF 4	N	
STRAY EXP 0	N	
STRAY EXP 1	N	
STRAY EXP 2	N	
STRAY EXP 3	N	
STRAY EXP 4	N	

Appendix E: Study Definition Examples

The following study definition examples should provide some level of insight into the study definition process. Although similar at first, each study type requires a unique set of data. This is why an understanding of the modeling is important. It is recommended that all of the examples be reviewed in order for the maximum effect. This is because repetition of thought has been avoided in cases where the study definition processes are similar.

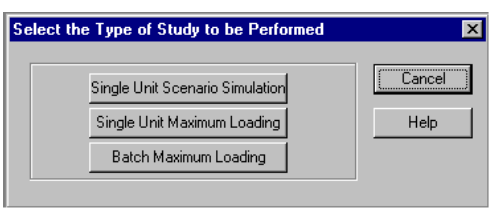
Single Transformer Simulation Study Definition

All study definitions begin by selecting the New Study item on the Study Menu with the mouse.



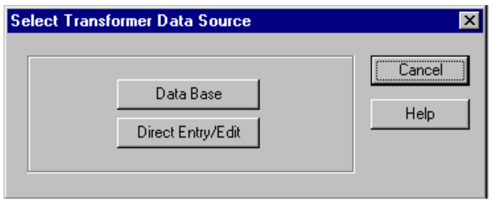
The New Study button on the tool bar can also be used to start the definition process.

Next, you will be prompted to make a choice as to the type of study to be performed. Once again, a mouse click is all that is required. In this example, "Single Unit Scenario Simulation (a.k.a. Simulation)" is selected.

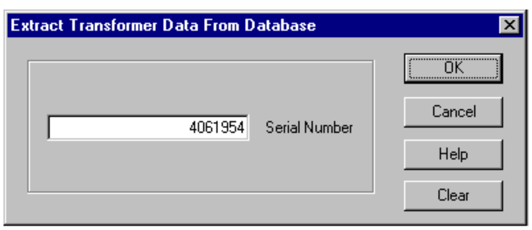


Once a Simulation is selected, the source of transformer data must be selected. The choices are: get the data from the transformer database, or manually enter every transformer parameter. The former is preferred when initially defining a study, while the latter option is handy when merely editing existing transformer data.

Assuming the database option was selected, you will be prompted for a serial number. The serial number is used as the "key" or index to the transformer database ("xfmr2.db"). The transformer database is actually formed from a query off of Substation Design and Standard's Major Equipment Database. Therefore, editing the local transformer database would not be wise because it eventually be written over with a new copy once the script is rerun. With this in mind, it is best to let Gary Schauffler know there is a problem or missing record that needs attention. Currently the records are being entered/fixed based on their relative loading,... highest first, lowest last. This order was based on information provided by Karl Grieve. Manual entry is feasible, but not recommended except for emergencies.

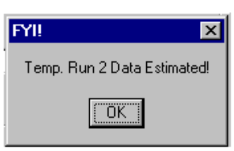


Once a (case insensitive) serial number is provided and accepted, the transformer database will be queried for the appropriate record.

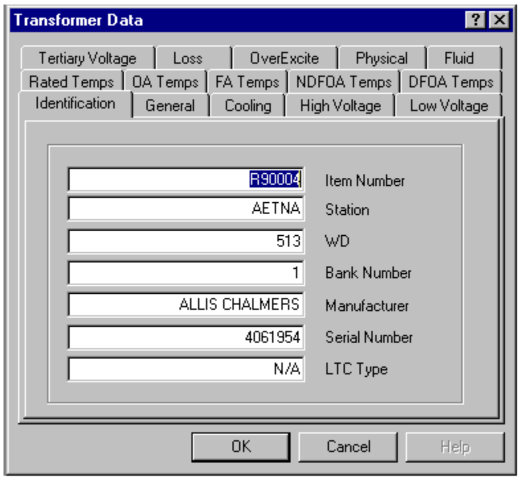


It is entirely possible that the record may not exist or may not be full of viable data. If the record is not found, you will be prompted. At that point you can either manually enter everything or let Gary know and wait for a table update to proceed.

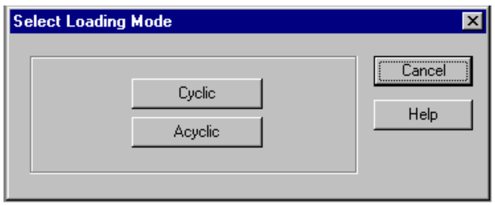
In some cases a record existed, but there was missing heat run data for the highest rated cooling mode. When this occurs, TLC will estimate the missing data and alert you to the fact. If you are not alerted then the data existed.



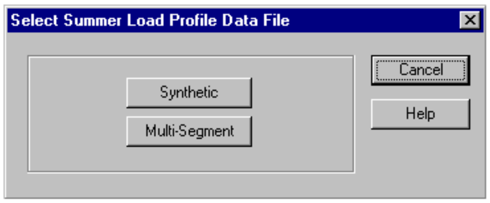
Assuming a record was found, the transformer property sheet will appear and be filled with the data from the record. Not all of the fields on the transformer property pages have directly associated fields in the table. In fact many don't and this gives rise to some difficulties. The data naming conventions on these pages correspond closely with those specified in the Thermal Model as defined in IEEE C57.91-Annex G. Unfortunately, these names do not always match those that are used in the Major Equipment Database and test sheets. The best advice I can give is to start with a full and accurate transformer record. From there TLC will fill in the blanks appropriately and estimate if possible. If necessary, the Database Desktop Application (watered down Paradox) or Paradox can be used to temporarily fix a record until a new master transformer table comes through.



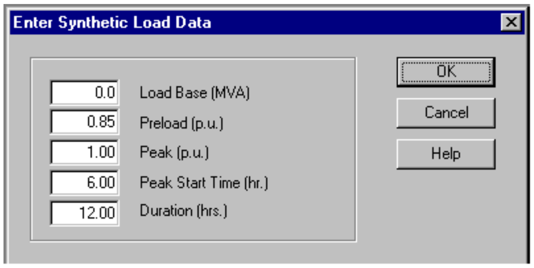
Once the transformer data is selected then you will be prompted to define the loading mode. The question being asked is "do you want to model yesterday as if it were the same as today?" You are being questioned so that the program will know how to establish the initial conditions. If yesterday was the same as today, then the loading is "cyclic." However, if you want TLC to treat yesterday as unique, then the loading is "acyclic" and you should be prepared to specify the initial load and ambient profiles required to model yesterday.

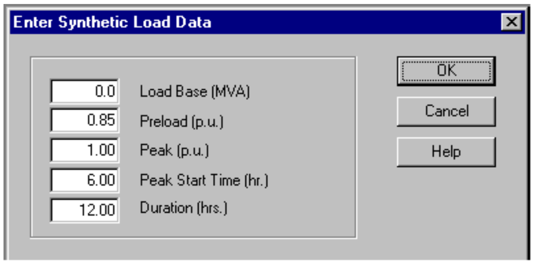


Once the loading mode is selected, then the source of the loading data must be decided. Synthetic and Multi-Segment options are available.

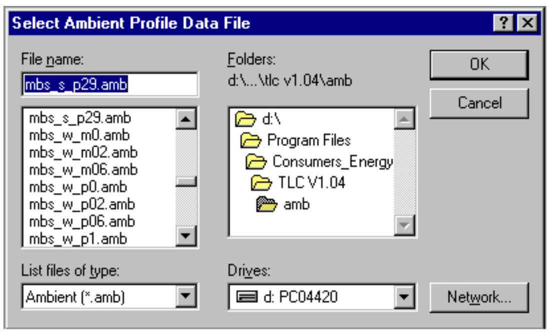


If Multi-Segment is selected then TLC will prompt you, with a “file select dialog,” to choose a “*.lod” file from the “lod” subdirectory. However, for this example, Synthetic is selected.

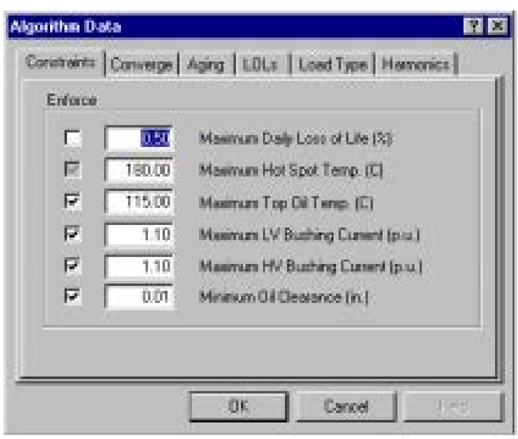




Synthetic load profiles are defined using the above dialog. The only entry that might throw you is the Load Base entry. If left at zero then TLC will use the MVA rating as a base for the synthetic profile. This is done on a per cooling mode basis. If a non-zero base is entered, then the profile becomes absolute across cooling modes and you will be able to see the effects of the load profile on the transformer with and without the fans or pumps. It is interesting to note that synthetic profiles, although entered directly, are actually stored and used by TLC as standard formatted "*.lod" files. Once the load profile is defined or selected, then the ambient profile must be selected.

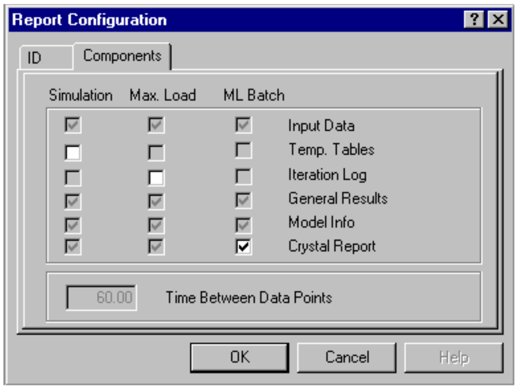


A file select dialog will prompt you to select an *.amb file from the amb subdirectory. Remember that if Acyclic loading was chosen, then you will be prompted for two scenarios... the initial (i.e., yesterday's) ambient and load, and the target (i.e., today's) ambient and load. However, since we selected Cyclic for this example, TLC will use today's scenario twice. Next, the algorithm parameters are set.

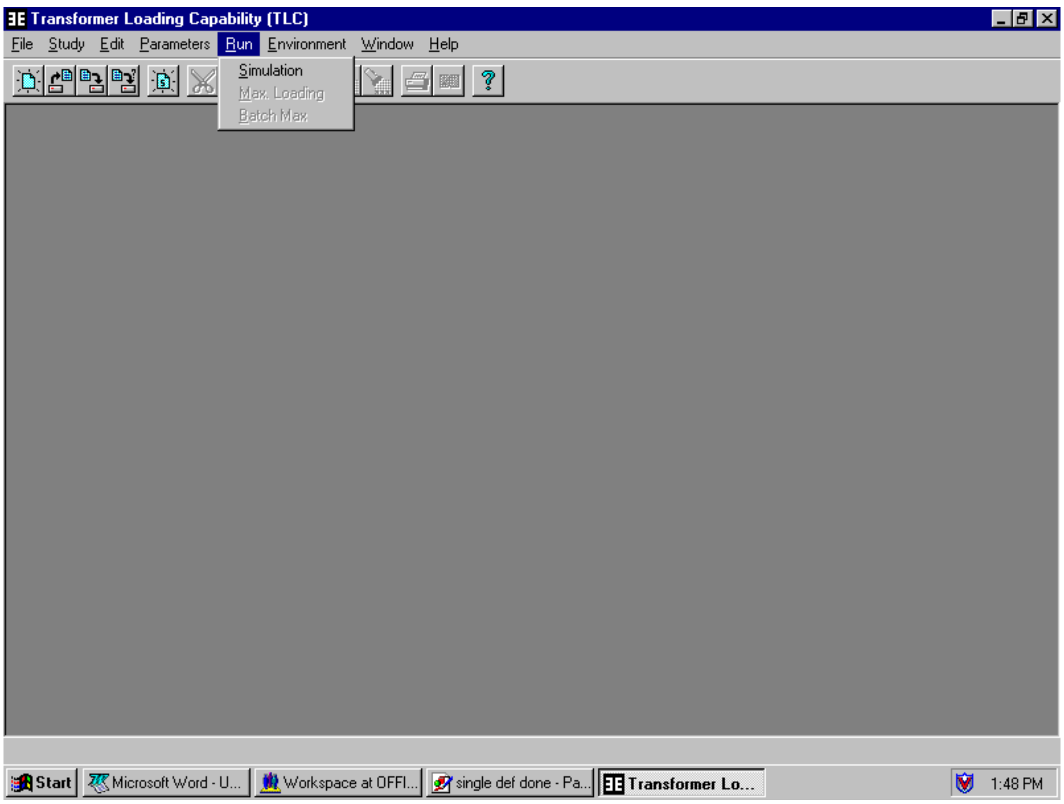


At this point you can tweak the algorithm parameters to suite your needs. Keep in mind that for simulations, constraint values do not really constrain anything. They simply serve as limits upon which flagging is based. For example, a simulation may determine that a top oil limit may be exceeded. The report should reflect that a "TO" violation occurred. However, no constrainment occurred. Constraints serve as true constraints in maximum loading studies.

You will then be given a chance to customize the out put report to some degree. After which the Simulation Study Definition Process is complete.



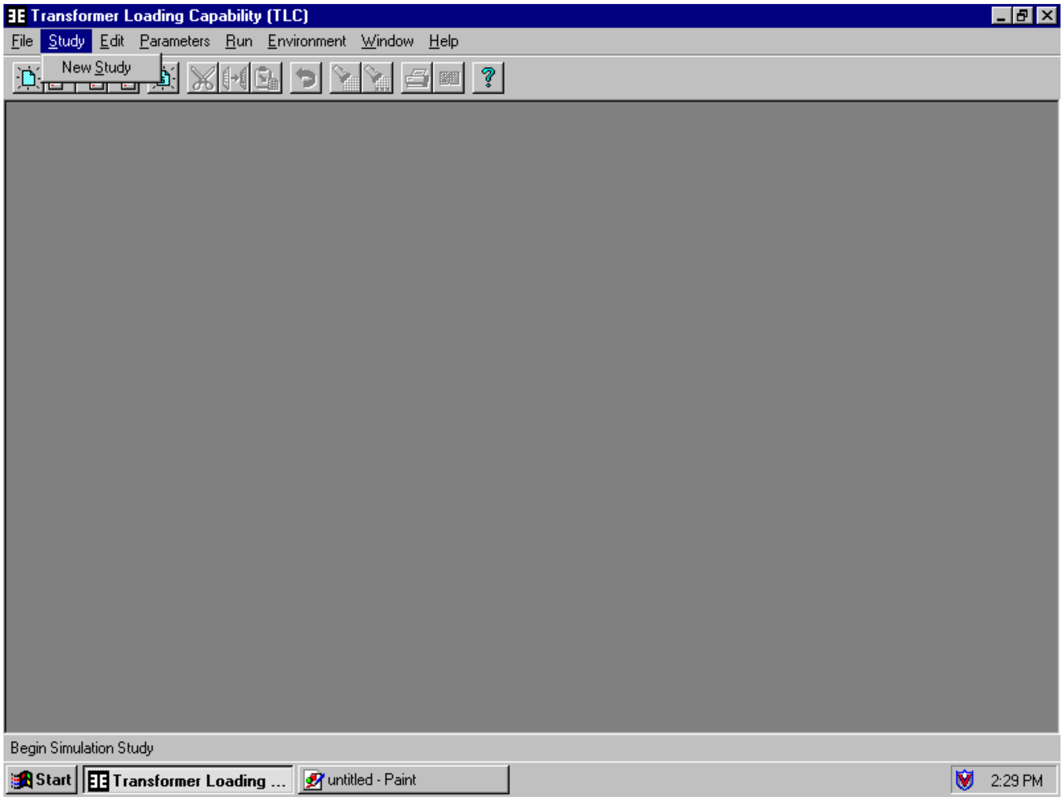
From there you are free to use the parameter menu to fine tune the study data or you can use the run menu to start the study.



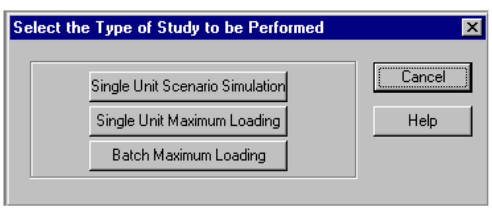
Upon successful completion of a Single Transformer Simulation Study, a Crystal Reports window will open with the results of the study formatted for printing. Although, the window suggests saving a report is a viable option, this canned operation of Crystal Reports is less than satisfying and so printing a hardcopy is the only true option. On some printers/computers, the fast forward button must be employed before printing to ensure that all of the report pages are printed.

Single Transformer Maximum Loading Study

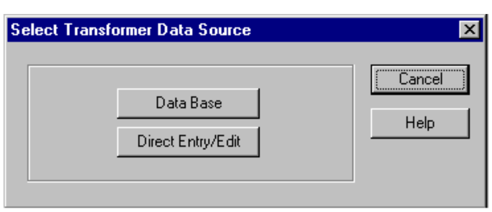
Once again, the study definition process begins by selecting the New Study item on the Study menu.



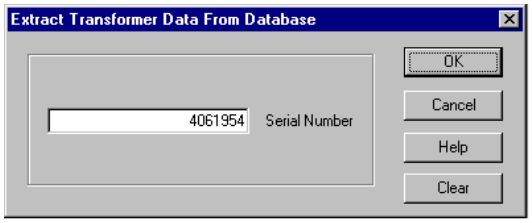
From there, for this example, Single Transformer Maximum Loading Study is selected.



Next, as was the case in the simulation example, you are prompted to select the source for transformer data. We naturally select “database” because we like to do things the easy way.

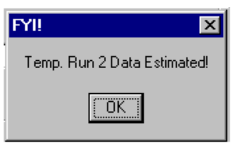


At that point we enter a valid serial number.

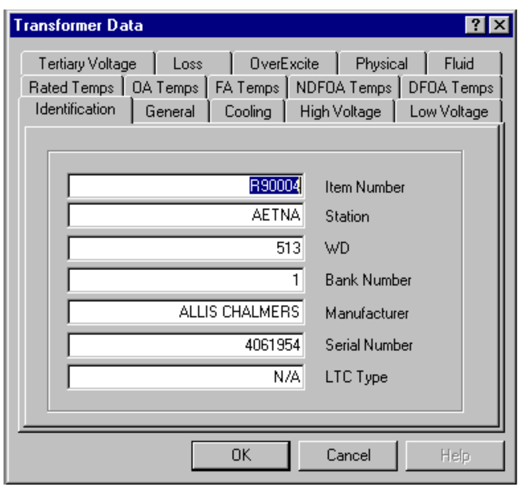


Once accepted, TLC either finds the record and fills the transformer data sheet or else it can't find the record and you must try a different method.

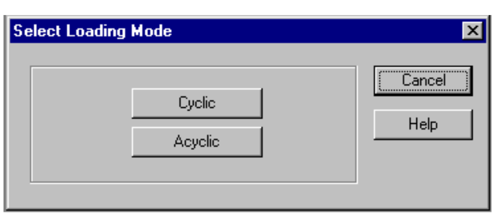
In some cases the record exists, but may be deficient in heat run data. If possible, TLC will estimate the missing data.



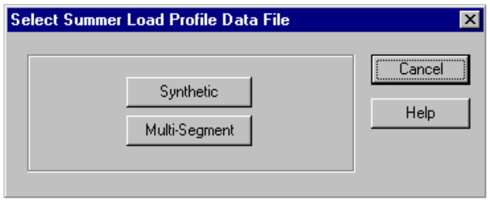
In this example, the record exists.



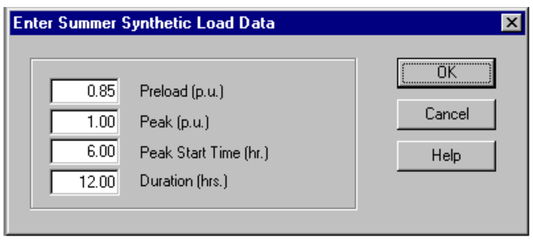
The transformer data looks good after reviewing the different pages, so we move on to the loading mode specification.



We currently perform all maximum loading type studies (single and multiple) assuming Cyclic Loading. As was the case for simulations, either Synthetic or Multi-Segment loads can be used.

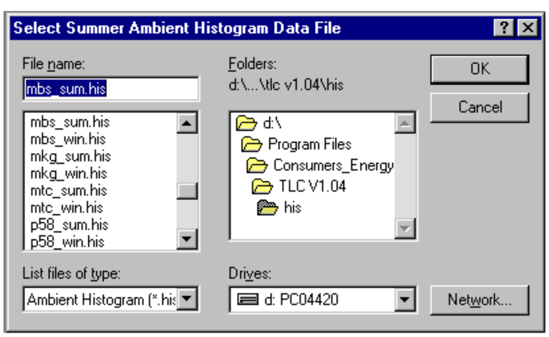


A critical note at this point is the WD and Bank Number data from the transformer record will now be used to recommend load and histogram files for both the summer and non-summer (winter) seasons. TLC finds these recommendations along with the load type data in the Location Database table. If a record doesn't exist for the given location, the default files (Environment Menu-File Specs Item) will be used. In this example though, Synthetic is selected to illustrate a point.

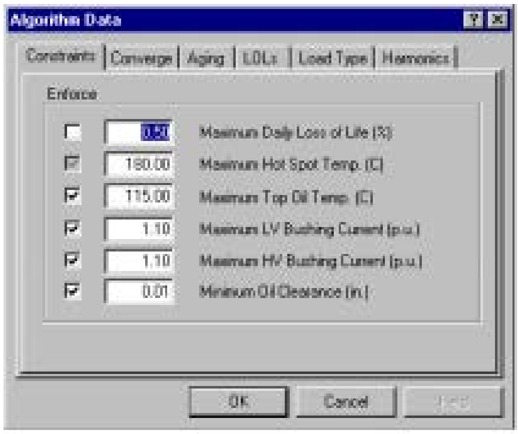


If you remember the Synthetic Load definition for simulation purposes had a load base field. This is not the case for Single Max Loading Studies. The base automatically is the MVA rating for the cooling mode currently being processed. Note that load profiles must be specified for each season.

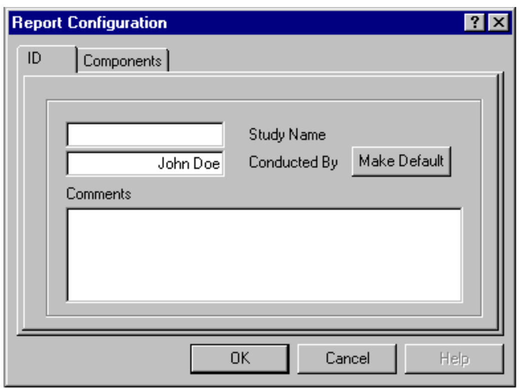
Next, histogram files must be specified for each season. You will be prompted to either accept the default files or select new ones.



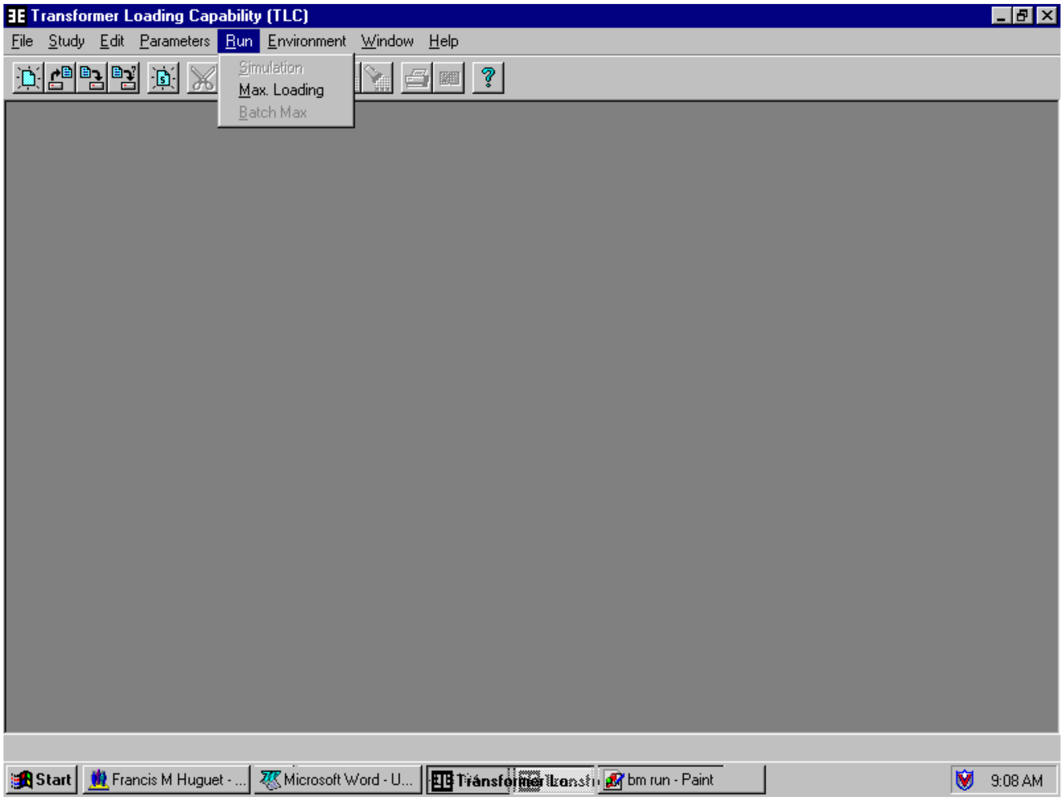
The algorithm parameters can now be adjusted to suit your needs.



Finally, the report parameters can specified.



Once accepted, the study definition is complete and you can now tweak the study using the Parameters Menu or execute the study using the Run Menu.

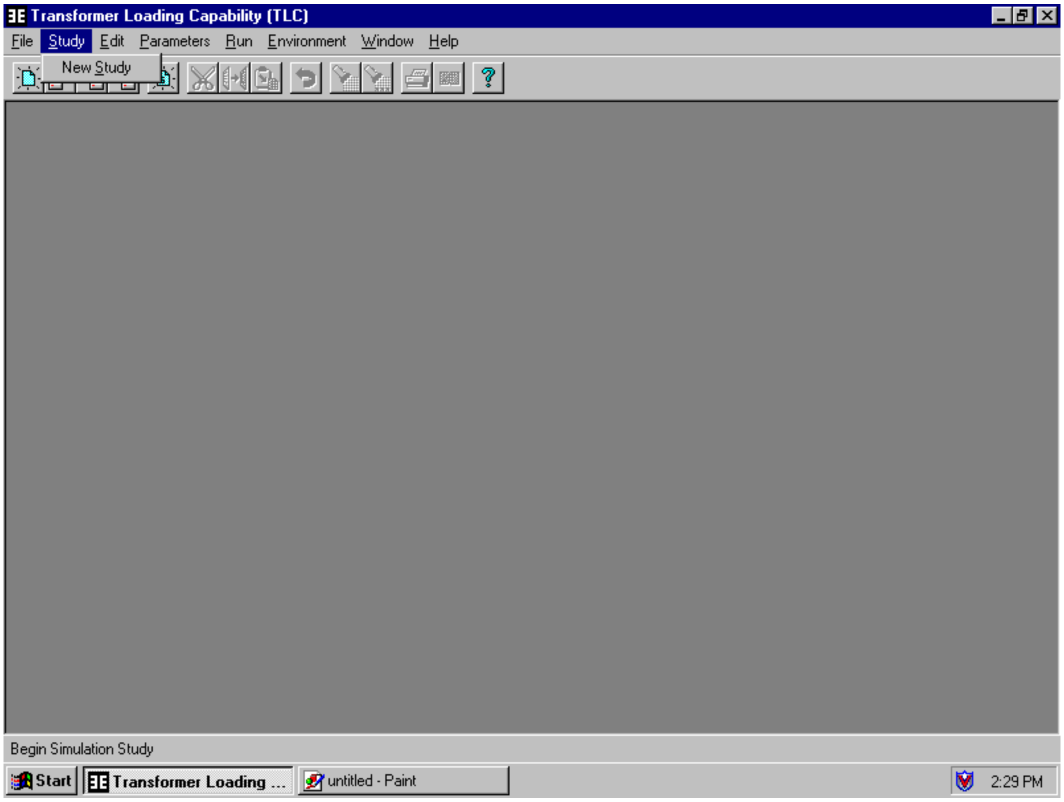


Multiple Transformer Maximum Loading Study Definition

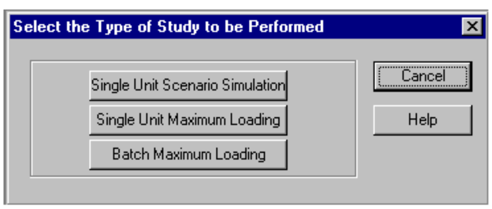
The Multiple Transformer Maximum Loading Study was the product of the Asset Utilization Project. The goal was to be able to perform capability studies en masse. It has evolved over time and become more robust with each passing revision. At this point, the practical maximum batch size is around 400 transformers. Even in that range, the program starts to crawl along. There are things that could be done to improve speed throughout the program, but optimization is not currently a high priority. The weak link in the whole TLC process is the transformer database. There is approximately 1900 transformer records in the table. Many of these records contain bad data. Hunting down the drawings and test sheets and then correcting the database is a sizable task. However, we are on our way. Sheela Philipose is dedicated to that end.

Study Definition Examples

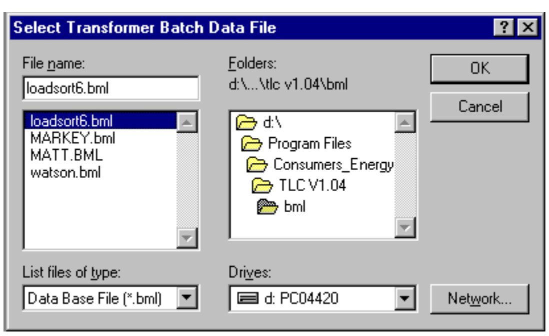
As usual, study definition begins with the Study Menu.



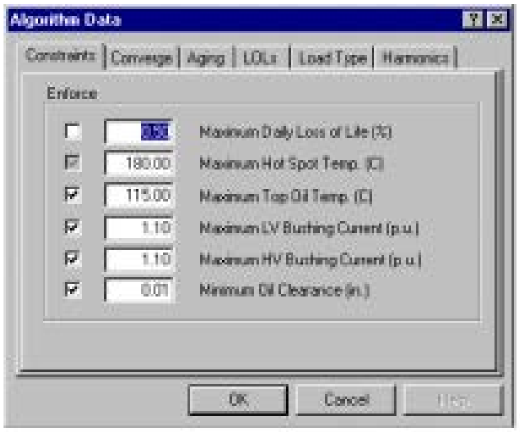
For this example, Multiple Transformer ("Batch") Maximum Loading is selected.



You are then prompted to select a properly formatted batch (*.bml) file from the bml subdirectory.



From there the algorithm parameters can be modified. Keep in mind that the hot spot temperature limit is changed for each transformer so it is not meaningful to modify it in the algorithm page when performing a Multiple Transformer Maximum Loading Study.



Next, the report configuration can be modified. Remember that two additional files are generated for batch studies: an output, and a reject file. The output file summarizes the report in a minimalistic text format, and the reject file lists the serial numbers of the transformers which the TLC was unable to process.

The study definition process is complete once the report parameters have been accepted.

Once the study is defined, it can be tweaked using the Parameters menu, or executed using the Run Menu.

Appendix F: TLC Program Version History

The TLC Program will undoubtedly continue to evolve over time. With each evolution, reports will reflect the current version number and thus there needs to be some historical record of the changes so "result" data can be interpreted accordingly. The following list denotes the versions and their highlights.

Version 0.95(b)

The first version of TLC that was actually given a version number and was exercised by Gary Schauffler. It was given a pre-"1.00" version number in anticipation of bugs and the impending official FMH-disconnection -from-Consumers.

Version 1.00

This version of the program represented the official completion of my (Fran Huguet) graduate student obligations to Consumers Energy. It handled Single Transformer Simulations and Single Transformer Maximum Loading Studies. Batch Mode was specifically not desired at that time. Data estimation and bad data detection code was minimal at that time. Overall the program was useful, but susceptible to bad data. A "setup" program was also developed to handle the installation requirements of the TLC program.

Version 1.01

Data estimation techniques evolved and helped make the program a little more useful and friendly. Some bugs were eliminated and stability became mainly a function of the data input.

Versions 1.02,1.03

The Asset Utilization Project (AU) called for the addition of a "Batch" mode. The mode was rapidly added to support the AU project. A new type of text file was developed to support the Batch mode. Each line required a serial number, seasonal histogram file data, load type data, and load profile file data. A variety of new "bad data" detection code was also added to keep the batch from bombing on bad data in the middle of huge batch runs. The transformer database started to really shine as the "weak link."

Version 1.04x

The batch text file format was simplified to only require serial numbers. A new "location" table was developed to tie load profiles, histograms, and load types to WDs and bank numbers. Karl Grieve was the guru behind the histogram data and load type data development. He is/was also responsible for marrying the WD and bank number to this data. These data are used behind the scenes by the Batch Max mode, but also serve as defaults whenever possible when defining Single Transformer Maximum Loading Studies. Bottom oil temperature estimation code was improved to incorporate Maria Pedula's findings with respect to typical "bottom oil-to-top oil temperature" differentials as a function of transformer design. The program and the "setup" program were tweaked to minimize the chance of problems with IS&T on managed NT workstations. A rigid directory structure was implemented to help organize the data files.

Version 1.05

If the user estimated the winding time constant too high, the previous versions of TLC would adjust the time constant down and also tweak several of the related test temperatures. For the most part this method worked well. However, several transformer continued to fail the stability check and the test data ended up skewed. Starting in this version (1.05), only the time constant is adjusted downward in cases where it is determined to be too high. A scaling factor of 0.7 is used, which reduces tau by 30% each iteration. Another noteworthy change in this version is that the data files and database tables were split from the Setup (installation) program. The data files and tables, which are more frequently updated, can now be updated using the Environment Menu in the TLC Program. When this method is used, batch files copy the master data files form the K: network drive to the local drive where the program is installed. With this new approach, the program will only need to be reinstalled when there are TLC program changes. Also, the updated (and spell-checked) User's Guide was converted to Acrobat form (pdf) and is automatically installed along with the program files. The guide is placed in the /txt subdirectory of the TLC directory.

Appendix G:Report Reading Examples

The Transformer Loading Capability Program requires a variety of input data and also is quite flexible as far as modeling is concerned. Consequently, the reports that TLC generates contain a lot of information and can be somewhat cryptic in nature. For these and other reasons a few notes on TLC Report reading may be helpful. The approach in this appendix is simply to include a few example reports and then comment on the various tagged areas. Many of the comments apply to all study types and so it is best to analyze all of the reports in the sequence presented so as to get the full effect.

Single Transformer Simulation Study Report

Please refer to the attached report labeled "1" for the following discussion. The fields that are not self-explanatory or are at least noteworthy have been tagged for correlation to the following commentary.

Section A.

This section identifies the type of study that was performed.

Section B.

Version data is critical when comparison of old TLC results to new TLC results will be required. The version number in combination with the version history documentation (Appendix F) should allow rectification of any unexpected discrepancies. Aesthetic changes will be saved up so that revisions will be kept to a minimum. However, if there is a bug or change that would impact the results, then a revision will expedited.

Section C.

If the Loading Mode was Cyclic then that means that initial conditions were determined by running the "target" profiles through the thermal model twice. However, if the Loading Mode was Acyclic, then either there is a unique set of "init" profiles for yesterday, or that the intial conditions were entered directly. The Source of Init Temp Data will either be simulation or direct entry. In any case, these data tell the user what fields on the rest of the report were actually used for this particular report. It will clear up a little more after reading the next few section comments.

Section D.

The "INIT" data document which files were used to determine the initial conditions. The remaining files were used for the "Target" day, that is, the day that the user wanted to simulate. The leading S prefix is a necessary evil which signifies "Summer" for maximum loading studies since the same report is used for both single transformer study types. In other words the "S" prefix doesn't mean anything for a Simulation type study. Another thing to remember here is that if the "Source of Init Temp Data" field of Section C was direct entry, then the init files are not applicable. Rather the initial temperature are documented int Section F. Conversely, if the source for intial temperature data was a simulation, then Section F has no bearing on this study. Eventually, a separate report may be developed to make things simpler. However, the track record thus far for TLC suggests that the program is primarily used for Maximum Loading Studies, not Simulations.

Section E.

This data is “not applicable” for simulations since a simulation only models a transformer’s thermal scenario for a single day. There is no concept of “season” involved. For Maximum Loading Studies the NS indicates Non-Summer (aka. winter).

Section F.

As noted earlier, this section only comes into play if the initial temperatures were entered directly.

Section G.

This section is another example of data on the report that may or may not have been in play for the results. These data represent the synthetic profile definitions. Sections C,D, and E determine whether or not the synthetics were used and if so, which ones.

Section H.

Remember the Summer Aging/ Annual Aging ratio? This ratio determines how the LOL targets are split between the seasons. This data has no bearing on a simulation study.

Section I.

Season has no meaning in a simulation report so it is “NA.”

Section J.

There are several possible Annual Loss-of-Life targets. For one of them, Emergency, the program does not constraint the capability using the aging calculations. The accumulated aging is still tracked, but it is for information only.

Section K.

Once again, aging targets don’t mean anything for a simulation. However, for maximum loading studies, the Seasonal Loss of Life target is found using the aging ratio of Section H and the ALOL targets.

Section L.

Accumulated Seasonal Loss of Life has no meaning in a simulation study. However, for maximum loading studies, aging is tracked and constrained for most of the capabilities. This number should be roughly equal to the SLOL target. If it is too far for comfort, the scaling factor or delta load can be reduced to make the algorithm converge tighter. However, the maximum iteration count may have to be increased accordingly.

Section M.

In a Simulation, the Max Load data indicates the peak load that was applied to the transformer. The temperature data fields indicate what the maximum temperature were during the simulation. For a Maximum Loading Study, the Max Load data is the capability estimation result for the associated season and seasonal aging limit. Typically it is somewhere between 100% and 200% of the nameplate rating for the cooling mode.

Section N.

For simulations, the violation data will indicate which, if any, enforced constraints were violated during the simulation. For Maximum Loading Studies, the violation data indicates which of the enforced constraints actually limited the capability. A “nl rec” may also appear here to indicate that a location record was not found for this particular location. In such cases, the default histogram and load files were used.

Single Transformer Maximum Loading Study Report

The report format for Single Transformer Maximum Loading (STML) Studies is the same as that for simulations. The report titled “2” is an example of a STML report.

Section O

The load type was for information only in a simulation report, but it plays a key role in a Maximum Loading Study. A set of multipliers, which are defined in the histogram files, are applied by the algorithm in order to reflect the relationship between average ambient temperature and peak load.

Section P

Note that, in this example study, the Emergency Summer Capability was limited by the Top Oil. If you look under the Max TO column on the same line you will notice that the max TO temperature was 114.3 degrees which is close to the 115 degree C constraint. How close the maximums get to the enforced constraints is closely tied to the load scaler (or the delta load). The finer the tweak, the more iterations are needed, and the longer each capability takes to process. It is just one of the many tradeoffs in life.

Multiple Transformer Maximum Loading Report

A Multiple Transformer Maximum Loading Study is really a Single Transformer Maximum Loading Study inside a loop fed by a transformer batch file with a few extra checks and automatic tweaks to keep the study from bombing. Thus, there isn’t much of a difference between the two types of reports. The main differences are that the transformer data is skipped for efficiency and reject codes are logged in the violation field so the user knows why a transformer was rejected. Report 3 is a example of a Multiple Transformer Maximum Loading Study Report.

Transformer Loading Capability (TLC) Report

STUDY NAME	1	Date	12/31/1999
PERSON	John Doe	Time	4:49:13PM
STUDY TYPE	Simulation	Version	1.04
COMMENTS	Example of a Single Transformer Simulation Study Report.		

A

B

Transformer and Algorithm Input Data

IDENTIFICATION:		SERIAL NUMBER	4061954		
		WD	513		
		ITEM NUMBER	R90004		
		BANK NUMBER	1		
		STATION 1	AETNA		
		MANUFACTURER	ALLIS CHALMERS		
		LTC TYPE	N/A		
		TRF WINDING	2 WINDER		
		PH	3		
ELECTRICAL:	H:	WDG RATING (MVA)	10/12.5	LOSS BASE (MVA)	10.00
		PH-PH VOLTAGE (kV)	46.00	TEMP BASE FOR LOSSES	75.00
		BUSHING RATING (A)	400.00	COPPER LOSS TEST (W)	64,700
		CONNECTION	DELTA	CORE LOSS TEST (W)	13,570
				WINDING EDDY (W)	0
	L:	WDG RATING (MVA)	10/12.5	HOTSPOT EDDY (W)	0
		PH-PH VOLTAGE (kV)	2.40	STRAY (W)	0
		BUSHING RATING (A)	4,000.00	OVEREXCITE	
		CONNECTION	DELTA	OVERCORE (W)	0
				OVERSTART (hr.)	0.00
				OVERDURATION (hrs.)	0.00
	T:	WDG RATING (MVA)			
		PH-PH VOLTAGE (kV)	0.00		
		BUSHING RATING (A)	0.00		
THERMAL:		AVAILABLE MODES	OA/FA		
		RATED AMBIENT (C)	30.00		
		RATED WDG TEMP RISE (C)	65.00		
		OA MODELED	Y	NDFOA MODELED	N
		OA MVA BASE FOR LOAD	10.00	NDFOA MVA BASE FOR LOAD	0.00
		OA TEST WDG AVE RISE (C)	61.60	NDFOA TEST WDG AVE RISE (C)	61.60
		OA TEST HS RISE (C)	76.60	NDFOA TEST HS RISE (C)	76.60
		OA TEST TO RISE (C)	57.40	NDFOA TEST TO RISE (C)	57.40
		OA TEST BO RISE (C)	42.40	NDFOA TEST BO RISE (C)	42.40
		FA MODELED	Y	DFOA MODELED	N
		FA MVA BASE FOR LOAD	12.50	DFOA MVA BASE FOR LOAD	0.00
		FA TEST WDG AVE RISE (C)	61.60	DFOA TEST WDG AVE RISE (C)	61.60
		FA TEST HS RISE (C)	76.60	DFOA TEST HS RISE (C)	76.60
		FA TEST TO RISE (C)	57.40	DFOA TEST TO RISE (C)	57.40
		FA TEST BO RISE (C)	42.40	DFOA TEST BO RISE (C)	42.40
PHYSICAL:		HV BIL (kV)	250.00		
		INS MOISTURE (%)	1.00		
		HOTSPOT HEIGHT (p.u.)	1.00		
		WDG TAU (min.)	5.00		
		WEIGHT CORE & COILS (lbs.)	25,660.00		
		WEIGHT CASE & ACCESS. (lbs.)	9,550.00		
		COND MATERIAL	Copper		
		FLUID TYPE	Mineral Oil		
		GALLONS OIL	1,905.00		
		25C OIL LEVEL (in.)	15.50		
		LIQUID LEVEL CHG	0.80		
		FLANGE CLEARANCE	2.00		
ALGORITHM:		LOADING MODE	Cyclic		
		SOURCE OF INIT TEMP DATA	Simulation		

C

Transformer Loading Capability (TLC) Report

STUDY NAME	1	Date	12/31/1999
PERSON	John Doe	Time	4:49:13PM
STUDY TYPE	Simulation	Version	1.04
COMMENTS	Example of a Single Transformer Simulation Study Report.		

(S) INIT AMB FILENAME	mbs_s_p29.amb
(S) INIT LOAD FILENAME	s_target.lod
(S) AMB FILENAME	mbs_s_p29.amb
(S) LOAD FILENAME	s_target.lod

D

NS INIT AMB FILENAME	NA
NS INIT LOAD FILENAME	NA
NS AMB FILENAME	NA
NS LOAD FILENAME	NA

E

INIT TEMPS DATA	
INIT HS TEMP (C)	30.00
INIT WDG TEMP (C)	30.00
INIT TO TEMP (C)	30.00
INIT DO TEMP (C)	30.00
INIT BO TEMP (C)	30.00

F

S SYNTHETIC: S_INIT.LOD		NS SYNTHETIC: NS_INIT.LOD	
IT PRELOAD (p.u.)	0.85	IT PRELOAD (p.u.)	0.85
IT PEAK (p.u.)	1.00	IT PEAK (p.u.)	1.00
IT STARTPEAK (hr.)	6.00	IT STARTPEAK (hr.)	6.00
IT DURATION	12.00	IT DURATION	12.00
S SYNTHETIC: S_TARGET.LOD		NS SYNTHETIC: NS_TARGET.LOD	
PRELOAD (p.u.)	0.85	PRELOAD (p.u.)	0.85
PEAK (p.u.)	1.00	PEAK (p.u.)	1.00
STARTPEAK (hr.)	6.00	STARTPEAK (hr.)	6.00
DURATION	12.00	DURATION (hrs.)	12.00

G

LOAD TYPE	Industrial, small Commercial
NORM INS LIFE (hrs.)	180,000.00
AGING CONSTANT B	15,000.00
SA AGE RATIO	0.50
AT BREAKPOINT 55 (C)	95.00
AT BREAKPOINT 65 (C)	110.00

H

LOAD ADJUST METHOD	Scale
DELTA LOAD (p.u.)	0.005
LOAD SCALER	1.010
MAX. ITERATIONS	500

MAX DLOL (%)	0.50	Not Enforced
MAX HOTSPOT TEMP (C)	180.00	Enforced
MAX TOP OIL TEMP (C)	115.00	Enforced
MAX HV BUSH CURRENT(p.u.)	1.10	Enforced
MAX LV BUSH CURRENT(p.u.)	1.10	Enforced
MIN OIL CLEARANCE (in.)	0.01	Enforced

General Results

SEASON	COOLING MODE	ALOL (%)	SLOL (%)	Acc. SLOL(%)	MAX LOAD (MVA)	MAX HS (C)	MAX TO (C)	MAX DLOL (%)	MAX HV BUSH (A)	MAX LV BUSH (A)	MIN OIL CLEAR	LAST VIOLATION (S)
NA	OA	NA	NA	NA	10.000	110.4	91.4	0.005	126	2,406	8.8	None
NA	FA	NA	NA	NA	12.500	111.0	91.9	0.006	157	3,007	8.7	None

I J K L M N

Model Information

The core algorithm of this program is based on Annex G of IEEE/ANSI Standard C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Transformers.

Transformer Loading Capability (TLC) Report

STUDY NAME	2	Date	12/31/1999
PERSON	John Doe	Time	4:53:17PM
STUDY TYPE	Single Max. Loading	Version	1.04
COMMENTS	Example of a Single Transformer Maximum Loading Study Report.		

Transformer and Algorithm Input Data

IDENTIFICATION:		SERIAL NUMBER	4061954		
		WD	513		
		ITEM NUMBER	R90004		
		BANK NUMBER	1		
		STATION 1	AETNA		
		MANUFACTURER	ALLIS CHALMERS		
		LTC TYPE	N/A		
		TRF WINDING	2 WINDER		
		PH	3		
ELECTRICAL:	H:	WDG RATING (MVA)	10/12.5	LOSS BASE (MVA)	10.00
		PH-PH VOLTAGE (kV)	46.00	TEMP BASE FOR LOSSES	75.00
		BUSHING RATING (A)	400.00	COPPER LOSS TEST (W)	64,700
		CONNECTION	DELTA	CORE LOSS TEST (W)	13,570
				WINDING EDDY (W)	0
	L:	WDG RATING (MVA)	10/12.5	HOTSPOT EDDY (W)	0
		PH-PH VOLTAGE (kV)	2.40	STRAY (W)	0
		BUSHING RATING (A)	4,000.00	OVEREXCITE	
		CONNECTION	DELTA	OVERCORE (W)	0
				OVERSTART (hr.)	0.00
				OVERDURATION (hrs.)	0.00
	T:	WDG RATING (MVA)			
		PH-PH VOLTAGE (kV)	0.00		
		BUSHING RATING (A)	0.00		
THERMAL:		AVAILABLE MODES	OA/FA		
		RATED AMBIENT (C)	30.00		
		RATED WDG TEMP RISE (C)	65.00		
		OA MODELED	Y	NDFOA MODELED	N
		OA MVA BASE FOR LOAD	10.00	NDFOA MVA BASE FOR LOAD	0.00
		OA TEST WDG AVE RISE (C)	61.60	NDFOA TEST WDG AVE RISE (C)	61.60
		OA TEST HS RISE (C)	76.60	NDFOA TEST HS RISE (C)	76.60
		OA TEST TO RISE (C)	57.40	NDFOA TEST TO RISE (C)	57.40
		OA TEST BO RISE (C)	42.40	NDFOA TEST BO RISE (C)	42.40
		FA MODELED	Y	DFOA MODELED	N
		FA MVA BASE FOR LOAD	12.50	DFOA MVA BASE FOR LOAD	0.00
		FA TEST WDG AVE RISE (C)	61.60	DFOA TEST WDG AVE RISE (C)	61.60
		FA TEST HS RISE (C)	76.60	DFOA TEST HS RISE (C)	76.60
		FA TEST TO RISE (C)	57.40	DFOA TEST TO RISE (C)	57.40
		FA TEST BO RISE (C)	42.40	DFOA TEST BO RISE (C)	42.40
PHYSICAL:		HV BIL (kV)	250.00		
		INS MOISTURE (%)	1.00		
		HOTSPOT HEIGHT (p.u.)	1.00		
		WDG TAU (min.)	5.00		
		WEIGHT CORE & COILS (lbs.)	25,660.00		
		WEIGHT CASE & ACCESS. (lbs.)	9,550.00		
		COND MATERIAL	Copper		
		FLUID TYPE	Mineral Oil		
		GALLONS OIL	1,905.00		
		25C OIL LEVEL (in.)	15.50		
		LIQUID LEVEL CHG	0.80		
		FLANGE CLEARANCE	2.00		
ALGORITHM:		LOADING MODE	Cyclic		
		SOURCE OF INIT TEMP DATA	Simulation		

Transformer Loading Capability (TLC) Report

STUDY NAME	2	Date	12/31/1999
PERSON	John Doe	Time	4:53:17PM
STUDY TYPE	Single Max. Loading	Version	1.04
COMMENTS	Example of a Single Transformer Maximum Loading Study Report.		

(S) INIT AMB FILENAME	mbs_sum.his		
(S) INIT LOAD FILENAME	0513_01_s.lod		
(S) AMB FILENAME	mbs_sum.his	INIT TEMPS DATA	
(S) LOAD FILENAME	0513_01_s.lod	INIT HS TEMP (C)	30.00
		INIT WDG TEMP (C)	30.00
NS INIT AMB FILENAME	mbs_win.his	INIT TO TEMP (C)	30.00
NS INIT LOAD FILENAME	0513_01_w.lod	INIT DO TEMP (C)	30.00
NS AMB FILENAME	mbs_win.his	INIT BO TEMP (C)	30.00
NS LOAD FILENAME	0513_01_w.lod		

S SYNTHETIC: S_INIT.LOD		NS SYNTHETIC: NS_INIT.LOD	
IT PRELOAD (p.u.)	0.85	IT PRELOAD (p.u.)	0.85
IT PEAK (p.u.)	1.00	IT PEAK (p.u.)	1.00
IT STARTPEAK (hr.)	6.00	IT STARTPEAK (hr.)	6.00
IT DURATION	12.00	IT DURATION	12.00
S SYNTHETIC: S_TARGET.LOD		NS SYNTHETIC: NS_TARGET.LOD	
PRELOAD (p.u.)	0.85	PRELOAD (p.u.)	0.85
PEAK (p.u.)	1.00	PEAK (p.u.)	1.00
STARTPEAK (hr.)	6.00	STARTPEAK (hr.)	6.00
DURATION	12.00	DURATION (hrs.)	12.00

LOAD TYPE	Industrial, small Commercial	
NORM INS LIFE (hrs.)	180,000.00	
AGING CONSTANT B	15,000.00	
SA AGE RATIO	0.50	
AT BREAKPOINT 55 (C)	95.00	
AT BREAKPOINT 65 (C)	110.00	
LOAD ADJUST METHOD	Scale	
DELTA LOAD (p.u.)	0.005	
LOAD SCALER	1.010	
MAX. ITERATIONS	500	
MAX DLOL (%)	0.50	Not Enforced
MAX HOTSPOT TEMP (C)	180.00	Enforced
MAX TOP OIL TEMP (C)	115.00	Enforced
MAX HV BUSH CURRENT(p.u.)	1.10	Enforced
MAX LV BUSH CURRENT(p.u.)	1.10	Enforced
MIN OIL CLEARANCE (in.)	0.01	Enforced

General Results

SEASON	COOLING MODE	ALOL (%)	SLOL (%)	Acc. SLOL(%)	MAX LOAD (MVA)	MAX HS (C)	MAX TO (C)	MAX DLOL (%)	MAX HV BUSH (A)	MAX LV BUSH (A)	MIN OIL CLEAR	LAST VIOLATION (S)
Summer	OA	Emergency	N/A	3.114	12.700	141.8	114.3	0.125	159	3,055	7.1	TO
Summer	OA	6.00	3.00	2.692	12.600	140.1	113.0	0.108	158	3,024	7.2	AccSLOL
Summer	OA	1.00	0.50	0.482	11.000	120.4	98.3	0.019	139	2,657	8.3	AccSLOL
Summer	FA	Emergency	N/A	2.361	15.300	139.9	114.4	0.102	191	3,669	7.1	TO
Summer	FA	6.00	3.00	2.361	15.300	139.9	114.4	0.102	191	3,669	7.1	TO
Summer	FA	1.00	0.50	0.451	13.700	121.0	99.4	0.019	172	3,289	8.2	AccSLOL
Non-Summer	OA	Emergency	N/A	4.918	13.700	146.1	114.5	0.153	173	3,308	7.2	TO
Non-Summer	OA	6.00	3.00	2.597	13.200	138.4	108.6	0.080	166	3,179	7.6	AccSLOL
Non-Summer	OA	1.00	0.50	0.461	11.700	118.7	93.8	0.014	147	2,821	8.7	AccSLOL
Non-Summer	FA	Emergency	N/A	3.404	16.400	143.4	114.5	0.117	205	3,934	7.1	TO
Non-Summer	FA	6.00	3.00	2.841	16.200	141.2	112.7	0.097	203	3,895	7.3	AccSLOL
Non-Summer	FA	1.00	0.50	0.459	14.500	120.2	95.9	0.015	182	3,491	8.5	AccSLOL

Transformer Loading Capability (TLC) Report

STUDY NAME	2	Date	12/31/1999
PERSON	John Doe	Time	4:53:17PM
STUDY TYPE	Single Max. Loading	Version	1.04
COMMENTS	Example of a Single Transformer Maximum Loading Study Report.		

Model Information

The core algorithm of this program is based on Annex G of IEEE/ANSI Standard C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Transformers.

Transformer Loading Capability (TLC) Report

STUDY NAME	3	Date	01/02/2000
PERSON	John Doe	Time	3:22:51PM
STUDY TYPE	Batch Max. Loading	Version	1.04
COMMENTS	Example of a Multiple Transformer Maximum Loading Study Report.		

Algorithm Input Data

ALGORITHM:	BATCH FILENAME	example.bml			
	LOADING MODE	Cyclic			
	SOURCE OF INIT TEMP DATA	Simulation			
	LOAD ADJUST METHOD	Scale			
	DELTA LOAD (p.u.)	0.005			
	LOAD SCALER	1.010			
	MAX. ITERATIONS	500			
	MAX DLOL (%)	0.50	Not Enforced	NORM INS LIFE (hrs.)	180,000.00
	MAX HOTSPOT TEMP (C)	var	Enforced	AGING CONSTANT B	15,000.00
	MAX TOP OIL TEMP (C)	var	Enforced	SA AGE RATIO	0.50
	MAX HV BUSH CURRENT(p.u.)	1.10	Enforced	AT BREAKPOINT 55 (C)	95.00
	MAX LV BUSH CURRENT(p.u.)	1.10	Enforced	AT BREAKPOINT 65 (C)	110.00
	MIN OIL CLEARANCE (in.)	0.01	Enforced		

Transformer Loading Capability (TLC) Report

STUDY NAME	3	Date	01/02/2000
PERSON	John Doe	Time	3:22:51PM
STUDY TYPE	Batch Max. Loading	Version	1.04
COMMENTS	Example of a Multiple Transformer Maximum Loading Study Report.		

Results

SERIAL NUMBER	STATION	MVA RATING	HV (kV)	LV (kV)	PH	TRF TYPE	LOAD TYPE
8567119	IRVING	0.75	46.0	8.3	3	AUTO	4

S LOAD	NS LOAD	S HIST	NS HIST
generic_s.lod	generic_w.lod	grr_sum.his	grr_win.his

SEASON	COOLING MODE	ALOL (%)	SLOL (%)	Acc SLOL(%)	MAX LOAD (MVA)	MAX HS (C)	MAX TO (C)	MAX DLOL (%)	MAX HV (A)	MAX LV (A)	MIN OIL CLEAR. (in.)	LAST VIOLATION (S)
Summer	OA	Emergency	NA	50.750	1.258	159.4	113.7	1.908	15.8	87.3	4.70	HS
Summer	OA	6.00	3.00	2.672	1.021	124.4	91.1	0.098	12.8	70.9	6.00	AccSLOL
Summer	OA	1.00	0.50	0.496	0.879	106.4	80.2	0.018	11.0	61.0	6.70	AccSLOL
Non-Summer	OA	Emergency	NA	54.410	1.296	159.3	110.4	1.948	16.3	90.0	4.90	HS
Non-Summer	OA	6.00	3.00	2.780	1.062	123.6	87.4	0.095	13.3	73.7	6.30	AccSLOL
Non-Summer	OA	1.00	0.50	0.451	0.915	104.3	75.6	0.015	11.5	63.5	7.00	AccSLOL

SERIAL NUMBER	STATION	MVA RATING	HV (kV)	LV (kV)	PH	TRF TYPE	LOAD TYPE
B315805	SAGINAW RIVER	30/37.5	138.0	23.0	3	3 WINDER	4

S LOAD	NS LOAD	S HIST	NS HIST
generic_s.lod	generic_w.lod	generic_sum.his	generic_win.his

SEASON	COOLING MODE	ALOL (%)	SLOL (%)	Acc SLOL(%)	MAX LOAD (MVA)	MAX HS (C)	MAX TO (C)	MAX DLOL (%)	MAX HV (A)	MAX LV (A)	MIN OIL CLEAR. (in.)	LAST VIOLATION (S)
Summer	OA	Emergency	NA	13.593	46.480	143.3	113.8	0.505	194.5	1,166.7	0.80	TO,nl rec
Summer	OA	6.00	3.00	2.982	41.248	125.7	100.9	0.108	172.6	1,035.4	2.40	AccSLOL,nl rec
Summer	OA	1.00	0.50	0.462	34.484	105.7	86.8	0.016	144.3	865.6	4.00	AccSLOL,nl rec
Summer	FA	Emergency	NA	7.815	52.076	137.8	100.8	0.299	217.9	1,307.2	2.50	LV,nl rec
Summer	FA	6.00	3.00	2.894	48.572	126.5	93.1	0.109	203.2	1,219.3	3.40	AccSLOL,nl rec
Summer	FA	1.00	0.50	0.461	41.838	106.8	80.4	0.017	175.0	1,050.2	4.90	AccSLOL,nl rec
Non-Summer	OA	Emergency	NA	16.012	49.339	143.6	114.1	0.570	206.4	1,238.5	0.90	TO,nl rec
Non-Summer	OA	6.00	3.00	2.845	42.923	123.8	96.8	0.099	179.6	1,077.5	2.90	AccSLOL,nl rec
Non-Summer	OA	1.00	0.50	0.487	36.606	104.5	83.3	0.015	153.1	918.9	4.50	AccSLOL,nl rec
Non-Summer	FA	Emergency	NA	4.634	52.076	129.0	91.3	0.166	217.9	1,307.2	3.70	LV,nl rec
Non-Summer	FA	6.00	3.00	2.973	50.544	124.0	88.0	0.105	211.5	1,268.8	4.10	AccSLOL,nl rec
Non-Summer	FA	1.00	0.50	0.463	43.972	104.3	75.5	0.016	184.0	1,103.8	5.50	AccSLOL,nl rec

SERIAL NUMBER	STATION	MVA RATING	HV (kV)	LV (kV)	PH	TRF TYPE	LOAD TYPE
D590603	SCOTT LAKE	30/40	138.0	46.0	3	AUTO	4

S LOAD	NS LOAD	S HIST	NS HIST
generic_s.lod	generic_w.lod	generic_sum.his	generic_win.his

SEASON	COOLING MODE	ALOL (%)	SLOL (%)	Acc SLOL(%)	MAX LOAD (MVA)	MAX HS (C)	MAX TO (C)	MAX DLOL (%)	MAX HV (A)	MAX LV (A)	MIN OIL CLEAR. (in.)	LAST VIOLATION (S)
Summer	OA	Emergency	NA	2.094	39.639	139.3	107.2	0.078	165.8	497.5	2.50	HS,nl rec
Summer	OA	6.00	3.00	2.094	39.639	139.3	107.2	0.078	165.8	497.5	2.50	HS,nl rec
Summer	OA	1.00	0.50	0.460	35.177	121.8	95.2	0.017	147.2	441.5	3.60	AccSLOL,nl rec
Summer	FA	Emergency	NA	1.718	50.287	138.8	109.7	0.069	210.4	631.2	2.20	HS,nl rec
Summer	FA	6.00	3.00	1.718	50.287	138.8	109.7	0.069	210.4	631.2	2.20	HS,nl rec
Summer	FA	1.00	0.50	0.459	45.979	123.7	98.1	0.018	192.4	577.1	3.30	AccSLOL,nl rec
Non-Summer	OA	Emergency	NA	2.124	40.840	138.5	103.9	0.073	170.9	512.6	2.80	HS,nl rec
Non-Summer	OA	6.00	3.00	2.124	40.840	138.5	103.9	0.073	170.9	512.6	2.80	HS,nl rec
Non-Summer	OA	1.00	0.50	0.479	36.606	121.2	92.0	0.016	153.1	459.4	3.90	AccSLOL,nl rec
Non-Summer	FA	Emergency	NA	1.967	52.328	139.1	107.3	0.076	218.9	656.8	2.50	HS,nl rec
Non-Summer	FA	6.00	3.00	1.967	52.328	139.1	107.3	0.076	218.9	656.8	2.50	HS,nl rec
Non-Summer	FA	1.00	0.50	0.475	47.846	122.6	94.7	0.018	200.2	600.5	3.70	AccSLOL,nl rec

Transformer Loading Capability (TLC) Report

STUDY NAME	3	Date	01/02/2000
PERSON	John Doe	Time	3:22:51PM
STUDY TYPE	Batch Max. Loading	Version	1.04
COMMENTS	Example of a Multiple Transformer Maximum Loading Study Report.		

Model Information

The core algorithm of this program is based upon Annex G of IEEE/ANSI Standard C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Transformers.

IEEE STANDARDS ASSOCIATION — IEEE

IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators

IEEE Power & Energy Society

Sponsored by the
Transformers Committee

IEEE
3 Park Avenue
New York, NY 10016-5997
USA

IEEE Std C57.91™-2011
(Revision of
IEEE Std C57.91-1995)

7 March 2012

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IEEE Std C57.91™-2011
(Revision of
IEEE Std C57.91-1995)

IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators

Sponsor

Transformers Committee
of the
IEEE Power & Energy Society

Approved 7 December 2011

IEEE-SA Standards Board

Abstract: General recommendations for loading 65 °C rise mineral-oil-immersed distribution and power transformers are covered.
Keywords: distribution transformer, IEEE C57.91, loading, mineral-oil-immersed, power transformer

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Introduction

This introduction is not part of IEEE Std C57.91-2011, IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators.

This guide is applicable to loading 65 °C mineral-oil-immersed distribution and power transformers. Guides for loading, IEEE Std C57.91-1981 (prior edition), IEEE Std C57.92™-1981,[a] and IEEE Std C57.115-1991 (redesignated as IEEE Std 756) are all combined in this document as the basic theory of transformer loading is the same, whether the subject is distribution transformers, power transformers 100 MVA and smaller, or transformers larger than 100 MVA. In recognition of different types of construction, special considerations, and the degree of conservatism involved in the loading of this equipment, specific sections are devoted to power transformers and distribution transformers. In the previously referenced information, the guide for units larger than 100 MVA referenced the IEEE Std C57.92-1981 loading guide for units up to and including 100 MVA.

This update to the work done in 1995 expands the scope to include step-voltage regulators and replaces Annex A with an improved discussion on bubble evolution. Subclause 8.4 was added for step-voltage regulators. In addition, the formula notations were changed to reflect the updated IEEE style and a number of typographical errors were fixed. Both Clause 7 and Annex G calculation procedures remain in place. Clause J was removed as out-of-date information and is expected to be re-introduced in the future in a new standard on transformer monitoring systems. Annex C and Annex G were changed from normative to informative.

As IEEE Std C57.12.00-2010[b] has adopted an insulation life of 180 000 hours at 110 °C, Table 2 of this guide has been moved to Annex I for historical reference.

In previous guides, different insulation aging curves were used for power transformers and distribution transformers. This was caused by the different evaluation procedures used. The distribution transformer curve was based on aging tests of actual transformers. The power transformer curve was based on aging insulation samples in test containers to achieve 50% retention of tensile strength. Investigation of cellulosic insulating materials removed from transformers that had long service life has led knowledgeable people to question the validity of the 50% criteria. One newer criteria suggested is 25% retention. This guide will permit the user to select the criteria most acceptable to their need, based on percent strength retention, polymerization index, etc. An insulation aging factor may thus be applied.

A per unit life concept and aging acceleration factor are provided in this loading guide. The equations given may be used to calculate percent loss of total insulation life, as has been the practice in earlier editions of the transformer loading guides. The relationship between insulation life and transformer life is a question that remains to be resolved. It is recognized that under the proper conditions, transformer life can well exceed the life of the insulation.

The assumed characteristics used in previous guides contained tables of loading capability based on assumed typical transformer characteristics. These assumed characteristics were recognized as not being those of actually built units, which may have a wide range of characteristics. In this guide these tables were removed since computer technology permits calculation of loading capability based on specific transformer characteristics.

Two methods of calculating temperatures are given in this guide. Clause 7 contains temperature equations similar to those used in previous editions of this guide. These equations use the winding hot spot rise over tank top oil and assume that the oil temperature in the cooling ducts is the same as the tank top oil during overloads. Recent research using imbedded thermocouples and fiber optic detectors indicates that the fluid

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[a] IEEE Std C57.92-1981 has been withdrawn; however, copies can be obtained from Global Engineering, 15 Inverness Way East, Englewood, CO 80112-5704, USA, tel. (303) 792-2181 (http://global.ihs.com/).
[b] Information of references can be found in Clause 2.

flow occurring in the windings during transient heating and cooling is an extremely complicated phenomena to describe by simple equations. These recent investigations have shown that during overloads, the temperature of the oil in the winding cooling ducts rises rapidly and exceeds the top-oil temperature in the tank. An alternate set of equations based on this concept is given in Annex G. The change of losses with temperature and liquid viscosity effects, and variable ambient temperature was incorporated into the equations. A computer program based on these equations is given for evaluation by the industry. Research in this field is ongoing at this time and may be incorporated into future revisions of this guide.

Changes in the guide, in addition to the consolidation, include information to more accurately load transformers operating down to a −30 °C ambient, this information concerns loss of diversity due to cold load pick-up or unusually low ambient temperatures.

Transformers rated 55 °C rise were generally replaced as a standard offering by most manufacturers about 1966. Their replacements were originally rated 55/65 °C and in 1977 the single 65 °C rated transformers became the industry standard offering. The higher temperature ratings are based on thermally upgraded oil-paper-enamel insulation systems. Loading of 55 °C insulation system transformers is covered in Annex D.

Suggestions for improvement gained in the use of this guide will be welcomed. They should be sent to the IEEE Standards Department.

Contents

IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators

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1. Overview

1.1 Scope

This guide provides recommendations for loading mineral-oil-immersed transformers and step-voltage regulators with insulation systems rated for a 65 °C average winding temperature rise at rated load. This guide applies to transformers ~~are included~~ manufactured in accordance with IEEE Std C57.12.00[1] and tested in accordance with IEEE Std C57.12.90, and step-voltage regulators manufactured and tested in ~~annex D because~~ accordance with IEEE Std C57.15. Because a substantial ~~percentage~~ population of ~~these~~ transformers and step-voltage regulators with insulation systems rated for 55 °C average winding temperature rise at rated load are still in service, recommendations that are specific to this equipment are also included.

1.2 Purpose

Applications of loads in excess of nameplate rating involve some degree of risk. It is the purpose of this guide to identify these risks and to establish limitations and guidelines, the application of which will minimize the risks to an acceptable level.

1Information of references can be found in Clause 2.

~~Risk areas are identified in clauses 4 and 9, and in the annexes as noted.~~

2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., they must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

~~This guide should be used in conjunction with the following publications. When the following publications are superseded by an approved revision, the revision should apply.~~

~~ANSI C57.12.10-1988, American National Standard for Transformers 230 kV and Below, 833/958 through 8333/10 417 kVA Single-Phase, and 750/862 through 60 000/80 000/100 000 kVA Three-Phase, without~~

~~**Load** Tap Changing; and 3750/4687 through 60 000/80 000/100 000 kVA with Load Tap Changing-Requirements.~~ ~~[1]~~

~~ANSI C57.12.20-1988, Requirements for Overhead-Type Distribution Transformers, 500 kVA and Smaller: High Voltage, 34 500 Volts and Below; Low Voltage, 7970/13 800Y and Below.~~

~~[1]ANSI publications are available from the Sales Department, American National Standards Institute, 11 West 42nd Street, 13thFloor, New York, NY 10036, USA.~~

~~ANSI C57.12.21-1980, Requirements for Pad-Mounted, Compartmental-Type, Self-Cooled, Single-Phase Distribution Transformers with High-Voltage Bushings (High-Voltage, 34 500 GrdY/19 920 Volts and Below; Low- Voltage, 240/120 Volts; 167 kVA and Smaller).~~

~~ANSI C57.12.22-1989, Pad-Mounted, Compartmental-Type, Self-Cooled, Three-Phase Distribution Transformers with High-Voltage Bushings, 2500 kVA and Smaller: High Voltage, 34 500 GrdY/19 920 Volts and Below; Low Voltage, 480 Volts and Below—Requirements.~~

~~ANSI C57.12.25-1990, Requirements for Pad-Mounted, Compartmental-Type, Self-Cooled, Single-Phase Distribution Transformers with Separable Insulated High-Voltage Connectors: High-Voltage, 34 500 GrdY/ 19 920 Volts and Below; Low Voltage 240/120 Volts; 167 kVA and Smaller.~~

IEEE Std C57.12.00™, IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers.[2, 3]

~~IEEE Std C57.12.26-1992, IEEE Standard for Pad-Mounted, Compartmental-Type, Self-Cooled, Three-Phase Distribution Transformers for Use with Separable Insulated High-Voltage Connectors (34 500 Grd Y/ 19 920 V and Below; 2500 kVA and Smaller) (ANSI).~~

IEEE Std C57.12.90™, IEEE Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers.

IEEE Std C57.15™, IEEE Standard Requirements, Terminology, and Test Code for Step-Voltage Regulators.

IEEE Std C57.100™, IEEE Standard Test Procedure for Thermal Evaluation of Insulation Systems for Liquid-Immersed Distribution and Power Transformers.

3. Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary: Glossary of Terms and Definitions*[4] should be consulted for terms not defined in this clause.

aging acceleration factor: For a given hottest-spot temperature, the rate at which transformer insulation aging is accelerated compared with the aging rate at a reference hottest-spot temperature. The reference hottest-spot temperature is 110 °C for 65 °C average winding rise and 95 °C for 55 °C average winding rise transformers (without thermally upgraded insulation). For hottest-spot temperatures in excess of the reference hottest-spot temperature, the aging acceleration factor is greater than 1. For hottest-spot temperatures lower than the reference hottest-spot temperature, the aging acceleration factor is less than 1.

directed flow (oil-immersed forced-oil-cooled transformers): The principal part of the pumped insulating fluid from heat exchangers or radiators is forced, or directed, to flow through specific paths in the winding.

non-directed flow (oil-immersed forced-oil-cooled transformers): Indicates that the pumped oil from heat exchangers or radiators flows freely inside the tank, and is not forced to flow through the windings.

percent loss of life: The equivalent aging in hours at the reference hottest-spot temperature over a time period (usually 24 h) times 100 divided by the total normal insulation life in hours at the reference hottest-spot temperature. The equivalent aging in hours at different hot-spot temperatures is obtained by multiplying the aging acceleration factors for the hottest-spot temperatures times the time periods of the various hottest-spot temperatures.

transformer insulation life: For a given temperature of the transformer insulation, the total time between the initial state for which the insulation is considered new and the final state for which dielectric stress, short circuit stress, or mechanical movement, which could occur in normal service, and could cause an electrical failure.

[2] IEEE publications are available from the Institute of Electrical and Electronics Engineers, 445 Hoes Lane, ~~P.O. Box 1331,~~ Piscataway, NJ 08854, USA.

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4. Effect of loading beyond nameplate rating

4.1 General

Applications of loads in excess of nameplate rating involve some degree of risk. While aging and long time mechanical deterioration of winding insulation have been the basis for the loading of transformers for many years, it is recognized that there are additional factors that may involve greater risk for transformers of higher megavoltampere and voltage ratings. The risk areas that should be considered when loading large transformers beyond nameplate rating are listed next. Further discussion regarding these risks is provided in Clause 9 or in the annexes, as noted.

a) Evolution of free gas from insulation of winding and lead conductors (insulated conductors) heated by load and eddy currents (circulating currents between or within insulated conductor strands) may jeopardize dielectric integrity. See Annex A for further discussion.

b) Evolution of free gas from insulation and insulating fluid adjacent to metallic structural parts linked by electromagnetic flux produced by winding or lead currents may also reduce dielectric strength.

c) Loss of life calculations may be made as described in Clause 5. If a percent loss of total life calculation is made based on an arbitrary definition of a "normal life" in hours, one should recognize that the calculated results may not be as conservative for transformers rated above 100 MVA as they are for smaller units since the calculation does not consider mechanical wear effects that may increase with megavoltampere rating.

d) Operation at high temperature will cause reduced mechanical strength of both conductor and structural insulation. These effects are of major concern during periods of transient overcurrent (through-fault) when mechanical forces reach their highest levels.

e) Thermal expansion of conductors, insulation materials, or structural parts at high temperatures may result in permanent deformations that could contribute to mechanical or dielectric failures.

f) Pressure build-up in bushings for currents above rating could result in leaking gaskets, loss of oil, and ultimate dielectric failure. See Annex B for further discussion.

g) Increased resistance in the contacts of tap changers can result from a build-up of oil decomposition products in a very localized high temperature region at the contact point when the tap changer is loaded beyond its rating. In the extreme, this could result in a thermal runaway condition with contact arcing and violent gas evolution. See Annex B for further discussion.

h) Auxiliary equipment internal to the transformer, such as reactors and current transformers, may also be subject to some of the risk identified above. See Annex B for further discussion.

i) When the temperature of the top oil exceeds 105 °C (65 °C rise over 40 °C ambient according to IEEE Std C57.12.00), there is a possibility that oil expansion will be greater than the holding capacity of the tank and also result in a pressure that causes the pressure relief device to operate and expel the oil. The loss of oil may also create problems with the oil preservation system or expose electrical parts upon cooling.

4.2 Voltage and frequency considerations

Voltage and frequency influences should be recognized when determining limitations for loading a transformer beyond its nameplate rating. This is true even though in all probability there may be little control of these parameters during a loading beyond nameplate rating event. ~~Subclause 4.1.6 in~~ IEEE Std C57.12.00~~-1993~~ defines the capability of a transformer to operate above rated voltage and below rated frequency. The user of this guide should recognize that, during conditions of loading beyond nameplate, the voltage regulation through the transformer may increase significantly (depending on the transformer impedance) due to the increased kilovoltampere loading and possibly dropping power factor.

A conservative guideline to prevent excessive core heating due to increased excitation is to reduce the transformer output volts per hertz limit by 1% for every 1% increase in voltage regulation during the loading beyond nameplate event. For example, if the voltage regulation at rated conditions is 6% and increases to 9% at some load above nameplate, the output volts per hertz limit might be reduced from 105% to 102%.

4.3 Supplemental cooling of existing self-cooled transformers

The load that can be carried on existing self-cooled transformers can usually be increased by adding auxiliary cooling equipment such as fans, external forced-oil coolers, or water spray equipment. The amount of additional loading varies widely, depending upon the following:

a) Design characteristics of the transformer
b) Type of cooling equipment
c) Permissible increase in voltage regulation
d) Limitations in associated equipment

No general rules can be given for such supplemental cooling, and each transformer should be considered individually.

The use of water spray equipment for supplemental cooling is not recommended for use in normal loading beyond nameplate rating. Appropriate precautions should be made for application of water spray equipment for supplemental cooling during emergency overloads. The major problem is the build up of scale on the cooling equipment due to minerals in the water. Over the long term this buildup will hinder the cooling efficiency. The spray and steam generated can also cause phase-to-phase flashover between bushings.

4.4 Information for user calculations

If the user intends to perform calculations to determine the loading capability of a transformer using Clause 7 or Annex G, the user should request the following minimum information in the specification or final test report:

a) Top-oil temperature rise over ambient temperature at rated load

b) Bottom-oil temperature rise over ambient temperature at rated load

c) Average conductor temperature rise over ambient temperature at rated load

d) Winding hottest-spot temperature rise over ambient temperature at rated load

e) Load loss at rated load

f) No-load (core) loss

g) Total loss at rated load

h) Confirmation of oil flow design (that is, directed or non-directed)

i) Weight of core and coil assembly

j) Weight of tank and fittings

NOTE —For the purpose of transient thermal calculations, the weight of tank and fittings to be used are only those portions that are in contact with heated oil.[5]

k) Volume of oil in the tank and cooling equipment (excluding LTC compartments, oil expansion tanks, etc.)

[5] Notes in text, tables, and figures are given for information only and do not contain requirements needed to implement the standard.

For all of the information in a) through g), the conditions under which the measurements were made (load, ambient temperature, tap, etc.) should be stated. If test data from thermally similar units is supplied the data shown on the test report should be corrected (in accordance with IEEE recommended procedures when issued) by the manufacturer using the actual design characteristics (losses, cooling surface, etc.) of the transformer supplied.

More precise calculations of loading capability may be performed if desired using Clause 7 or Annex G if the following additional information is provided:

– Load loss at rated load at rated and tap extremes or all possible tap connection combinations

– Winding resistance at tap extremes or all possible tap combinations

More precise calculations of loading capability may be performed if desired using Annex G if the following additional information is also provided:

– Total stray and eddy loss as a percent of total load loss and estimated stray and eddy loss

– Per unit eddy loss at hot spot location

– Per unit winding height to hot spot location

The temperature rise test is performed (and calculations of temperature rises made when a test is not performed) on the maximum loss tap position. This data results in conservative predictions of loading capability when the transformer is operated on other than the maximum loss tap. To achieve more accurate predictions of the capability of a transformer based on the actual loading cycle and tap connections, several adjustments may be made of the data presented in the test report before the data is used as input to loading calculations. These adjustments are provided in the following:

– Load cycle in kVA on the actual combination of tap connections~~.~~

– Use the measured or calculated load losses for that tap connection~~.~~

– Correct the temperature rise test data for the lower losses or different rated current~~.~~

– Determine if the hottest-spot winding gradient changes with changes in the tap connections~~.~~

Calculating the effect of load tap changer operation into the loading predictions is an extremely complicated and controversial subject and the effect may vary with manufacturer. For some designs the effect of load tap changer operation may have a negligible effect on temperature rises of the transformer windings.

5. Transformer insulation life

5.1 General

The subject of loss of transformer insulation life has had a rich but controversial history of development, with distribution and power transformers taking independent research paths (refer to I.1 in Annex I). As a result of recent study and testing, the approach to determination of insulation loss of life in this guide has been significantly modified (refer to I.2 in Annex I.) Aging or deterioration of insulation is a time function of temperature, moisture content, and oxygen content. With modern oil preservation systems, the moisture and oxygen contributions to insulation deterioration can be minimized, leaving insulation temperature as the controlling parameter. Since, in most apparatus, the temperature distribution is not uniform, the part that is operating at the highest temperature will ordinarily undergo the greatest deterioration. Therefore, in aging studies it is usual to consider the aging effects produced by the highest (hottest-spot) temperature. Because many factors influence the cumulative effect of temperature over time in causing deterioration of transformer insulation, it is not possible to predict with any great degree of accuracy the useful life of the insulation in a transformer, even under constant or closely controlled conditions, much less under widely varying service conditions. Wherever the word "life" is used in this guide, it means calculated insulation life, not actual transformer life.

5.2 Aging equations

Experimental evidence indicates that the relation of insulation deterioration to time and temperature follows an adaptation of the Arrhenius reaction rate theory that has the following form:

$$\text{Per Unit Life} = A\, e^{\left[\frac{B}{\Theta_H + 273}\right]}$$

where

Θ_H is the winding hottest-spot temperature, °C

A is a constant

B is a constant

e is the base of the natural logarithm

The transformer per unit insulation life curve of Figure 1 relates per unit transformer insulation life to winding hottest-spot temperature. This curve should be used for both distribution and power transformers because both are manufactured using the same cellulose conductor insulation. The use of this curve isolates temperature as the principal variable affecting thermal life. It also indicates the degree to which the rate of aging is accelerated beyond normal for temperature above a reference temperature of 110 °C and is reduced below normal for temperature below 110 °C (see discussion in I.2 of Annex I). The equation for the curve is as follows:

$$\text{Per Unit Life} = 9.8 \times 10^{-18}\, e^{\left[\frac{15000}{\Theta_H + 273}\right]} \quad (1)$$

where

Θ_H is the winding hottest-spot temperature, °C

The per unit transformer insulation life curve (Figure 1) can be used in the following two ways. It is the basis for calculation of an aging acceleration factor (F_{AA}) for a given load and temperature or for a varying load and temperature profile over a 24 h period. A curve of F_{AA} vs. hottest-spot temperature for a 65 °C rise insulation system is shown in Figure 2 and values are tabulated in Table 1. F_{AA} has a value greater than 1 for winding hottest-spot temperatures greater than the reference temperature 110 °C and less than 1 for temperatures below 110 °C. The equation for F_{AA} is as follows:

$$F_{AA} = e^{\left[\frac{15000}{383} - \frac{15000}{\Theta_H + 273}\right]} \quad (2)$$

where

F_{AA} is the aging acceleration factor
Θ_H is the winding hottest-spot temperature, °C

Equation (2) may be used to calculate equivalent aging of the transformer. The equivalent aging factor at the reference temperature ~~that will be consumed~~ in a given time period for the given temperature cycle is the following:

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA,n} \Delta t_n}{\sum_{n=1}^{N} \Delta t_n} \qquad (3)$$

where

F_{EQA} is equivalent aging factor for the total time period

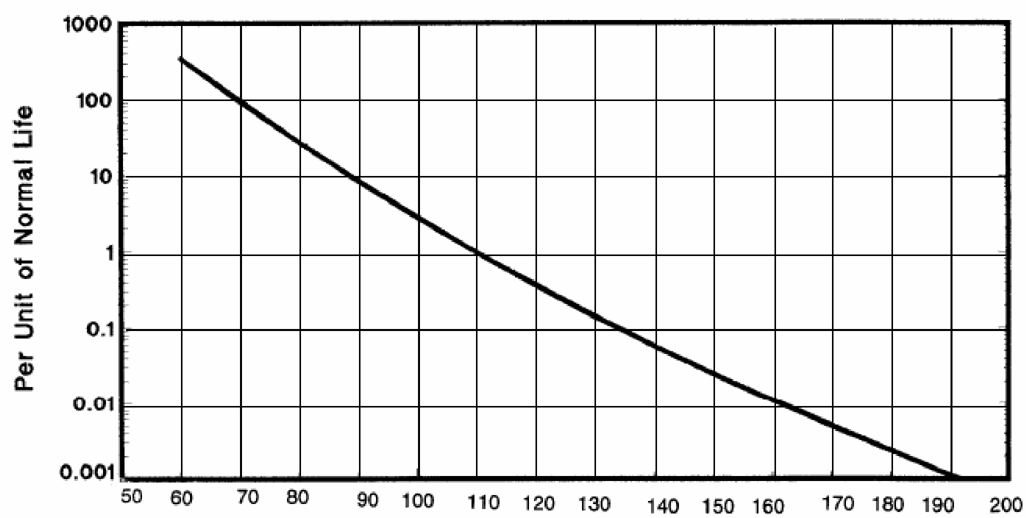
$F_{AA,n}$ is aging acceleration factor for the temperature that exists during the time interval Δt_n

n is index of the time interval, Δt

N is total number of time intervals

Δt_n is time interval, h

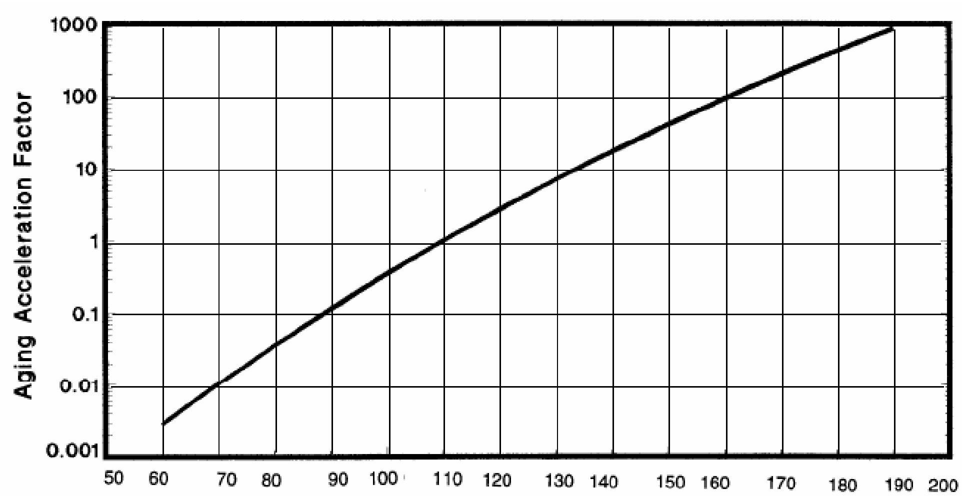
See Annex I for example calculations.



Hottest Spot Temperature

Degree C

Figure 1 — Transformer insulation life



Hottest Spot Temperature

Degree C

Figure 2 — Aging acceleration factor (relative to 110 °C)

Table 1—Aging acceleration factor

Temperature °C	Age factor	Temperature °C	Age factor	Temperature °C	Age factor
<37	0.0000	91	0.1295	146	28.9315
37	0.0001	92	0.1449	147	31.5115
38	0.0001	93	0.1622	148	34.3015
39	0.0001	94	0.1813	149	37.3215
40	0.0002	95	0.2026	150	40.5915
41	0.0002	96	0.2263	151	44.1315
42	0.0002	97	0.2526	152	47.9615
43	0.0002	98	0.2817	153	52.1015
44	0.0003	99	0.3141	154	56.5815
45	0.0003	100	0.3499	155	61.4215
46	0.0004	101	0.3897	156	66.6516
47	0.0004	102	0.4337	157	72.3016
48	0.0005	103	0.4823	158	78.3916
49	0.0006	104	0.5362	159	84.9716
50	0.0007	105	0.5957	160	92.0616
51	0.0008	106	0.6614	161	99.7116
52	0.0009	107	0.7340	162	107.9616
53	0.0011	108	0.8142	163	116.8416

54	0.0012	109	0.9026	164	126.4116
55	0.0014	110	1.0000	165	136.7216
56	0.0016	111	1.1074	166	147.8117
57	0.0019	112	1.2256	167	159.7517
58	0.0021	113	1.3558	168	172.5817
59	0.0024	114	1.4990	169	186.3917
60	0.0028	115	1.6565	170	201.2317
61	0.0032	116	1.8296	171	217.1817
62	0.0037	117	2.0197	172	234.3017
63	0.0042	118	2.2285	173	252.7017
64	0.0048	119	2.4576	174	272.4517
65	0.0054	120	2.7089	175	293.6417
66	0.0062	121	2.9845	176	316.3718
61	0.0071	122	3.2865	177	340.7518
68	0.0080	123	3.6172	178	366.8918
69	0.0091	124	3.9793	179	394.9118
70	0.0104	125	4.3756	180	424.9218
71	0.0118	126	4.8091	181	457.0718
72	0.0134	127	5.2830	182	491.5018
73	0.0152	128	5.8009	183	528.3518
74	0.0172	129	6.3665	184	567.7818
75	0.0195	130	6.9842	185	609.9618
76	0.0220	131	7.6582	186	655.0819
77	0.0249	132	8.3935	187	703.3119
78	0.0281	133	9.1952	188	754.8619
79	0.0318	134	10.0689	189	809.9419
80	0.0358	135	11.0208	190	868.7719
81	0.0404	136	12.0573	191	931.6019
82	0.0455	137	13.1856	192	998.6719
83	0.0513	138	14.4131	193	1070.2519
84	0.0577	139	15.7481	194	1146.6219
85	0.0649	140	17.1994	195	1228.0819
86	0.0729	141	18.7765	196	1314.9420
87	0.0819	142	20.4895	197	1407.5420
88	0.0919	143	22.3493	198	1506.2220
89	0.1031	144	24.3679	199	1611.3520
90	0.1156	145	26.5578	200	1723.3420

5.3 Percent loss of life

The insulation per unit life curve (see Figure 1) can also be used to calculate percent loss of total life, as has been the practice in earlier editions of the referenced transformer loading guides. To do so, it is necessary to arbitrarily define the normal insulation life at the reference temperature in hours or years. Benchmark values of normal insulation life for a well-dried, oxygen-free system can be selected from Table I.2. Then the hours of life lost in the total time period is determined by multiplying the equivalent aging determined in Equation (3) by the time period (t) in hours. This gives equivalent hours of life at the reference temperature that are consumed in the time period. Percent loss of insulation life in the time period is equivalent hours life consumed divided by the definition of total normal insulation life (h) and multiplied by 100. Usually the total time period used is 24 h. The equation is given as follows:

$$\%\ \text{Loss of life} = \frac{F_{EQA} \times t \times 100}{\text{Normal insulation life}} \tag{4}$$

where

F_{EQA} is equivalent aging factor for the total time period

Per 5.11.3 of IEEE Std C57.12.00-2010, a minimum normal insulation life expectancy of 180 000 hours is required. Other values for the end of life criteria have been used historically for developing transformer loading capability studies. The equations provided in this clause include a variable for the end of life criteria, so those users who have used alternative values may continue to do so. The end of life criteria are described in Table I.2 of Annex I.

The time duration for continuous operation at hottest-spot temperatures above rated that give different percent loss of life may be calculated using Equation (4). Table 2 gives time durations for various loss of life based on a normal life of 180 000 h. Normal percent loss of life for operation at a rated hottest-spot temperature of 110 °C for 24 h is 0.0133%.

Table 2—Time durations in hours for continuous operation above rated hottest-spot temperature for different loss of life values

Hot spot temp °C	F_{AA}	Percent loss of life[a]						
		0.0133[b]	0.02	0.05	0.1	0.2	0.3	0.4
110	1.00	24	—	—	—	—	—	—
120	2.71	8.86	13.3	—	—	—	—	—
130	6.98	3.44	5.1	12.9	—	—	—	—
140	17.2	1.39	2.1	5.2	10.5	20.9	—	—
150	40.6	0.59	0.89	2.2	4.4	8.8	13.3	17.7
160	92.1	0.26	0.39	0.98	1.96	3.9	5.9	7.8
170	201.2	0.12	0.18	0.45	0.89	1.8	2.7	3.6
180	424.9	0.06	0.08	0.21	0.42	0.84	1.27	1.7
190	868.8	0.028	0.04	0.10	0.21	0.41	0.62	0.82
200	1723	0.014	0.02	0.05	0.10	0.21	0.31	0.42

[a] Based on a normal life of 180 000 h. Time durations not shown are in excess of 24 h.

[b] This column of time durations for 0.0133% loss of life gives the hours of continuous operation above the basis-of-rating hottest-spot temperature (110 °C) for one equivalent day of operation at 110 °C

6. Ambient temperature and its influence on loading

6.1 General

Ambient temperature is an important factor in determining the load capability of a transformer since the temperature rises for any load must be added to the ambient to determine operating temperatures. Transformer ratings are based on a 24 h average ambient of 30 °C. This is the standard ambient used in this guide. Whenever the actual ambient can be measured, such ambients should be averaged over 24 h, and then used in determining the transformer's temperature and loading capability. The ambient air temperature seen by a transformer is the air in contact with its radiators or heat exchangers. In some installations the transformer may be outdoors but surrounded by buildings or sound deadening walls. This may result in recirculation of air, and the ambient should be adjusted accordingly.

6.2 Approximating ambient temperature for air-cooled transformers

It is often necessary to predict the load that a transformer can safely carry at some future time in an unknown ambient. The probable ambient temperature for any month may be approximated from data in reports prepared by the national or local atmospheric authority for the sections of the country where the transformer is located.

a) *Average temperature*. Use average daily temperature for the month involved, averaged over several years.

b) *Maximum daily temperature*. Use average of the maximum daily temperatures for month involved averaged over several years.

These ambients should be used as follows:

– For loads with normal life expectancy, use a), the average temperature as the ambient for the month involved.

– For short-time loads with moderate sacrifice of life expectancy, use b), the maximum daily temperature for the month involved.

During any one day the 24 h average of temperature may exceed the value derived from a) or b) above. To be conservative it is recommended that these temperatures be increased by 5 °C since aging at higher than average temperature is not fully compensated by decreased aging at lower than average temperature. With this margin the approximated 24 h average temperature will not be exceeded on more than a few days per month and, where it is exceeded, the additional loss of life will not be serious.

6.3 Approximating ambient temperature for water-cooled transformers

The ambient temperature to be used for water-cooled transformers is the cooling water temperature plus an added 5 °C to allow for possible loss of cooling efficiency due to deposits on cooling coil surfaces of water-cooled transformers in service.

6.4 Influence of ambient on loading for normal life expectancy

Average ambient temperatures should cover 24 h time periods. The associated maximum temperatures should not be more than 10 °C above the average temperatures for air-cooled, and 5 °C for water-cooled transformers. Since ambient temperature is an important factor in determining the load capability of a transformer, it should be controlled for indoor installations by adequate ventilation and should always be considered in outdoor installations.

Table 3 gives the increase or decrease from rated kVA for other than average daily ambients of 30 °C for air and 25 °C for water. It is recommended that a 5 °C margin be used when applying the factors from Table 3. It should be pointed out that the increase or decrease obtained from Table 3 is conservative, and therefore do not check exactly with calculations using the equations in Clause 7. Table 3 is for quick approximations, only. Loading on the basis of ambient temperature with loads permitted in Table 3 will give approximately the same life expectancy as if transformers were operated at nameplate rating and standard ambient temperatures over the same period. Table 3 covers a range in average ambient temperatures of –30 °C to 50 °C for cooling air. A check should be made with the manufacturer before loading on the basis of ambient air less than –30 °C or greater than 50 °C.

Table 3—Loading on basis of temperatures (average ambient other than 30 °C and average winding rise less than limiting values) (for quick approximation) (ambient temperature range –30 °C to 50 °C)

Type of cooling	% of kVA rating	
	Decrease load for each °C higher temperature	**Increase load for each °C lower temperature**
Self-cooled—ONAN	1.5	1.0
Water-cooled—ONWF	1.5	1.0
Forced-air-cooled—ONAN/ONAF, ONAN/ONAF/ONAF	1.0	0.75
Forced-oil, -air, -water-cooled—OFAF, OFWF, ODWF, and ONAN/OFAF/OFAF	1.0	0.75

7. Calculation of temperatures

7.1 Load cycles

7.1.1 Load cycles, general

Transformers usually operate on a load cycle that repeats every 24 h. A typical normal load cycle, such as shown in Figure C.1 of Annex C, consists of load fluctuations throughout the day. For normal loading or planned overloading above nameplate, a multi-step load cycle calculation method is usually used. The 24 h load profile is described by a series of constant loads of a short duration (usually 1/2 h or 1 h). The equivalent load during the short time steps may be determined by the method of 7.1.2 or by using the maximum peak load during the short-time period under consideration. This method is usually used in computer programs.

An equivalent two step overload cycle as shown in Figure 3 may be used for determining emergency overload capability using the Equation (5) through Equation (22). The equivalent two-step load cycle consists of a prior load and a peak load. This figure is also used for the purpose of describing calculations to determine equivalent load cycles. There is usually one period in the daily load cycle when the load builds up to a considerably greater value than any reached at other times, such as shown by the solid line in the overload cycle in Figure 3. Generally, the maximum value or peak load is not reached and passed suddenly, but builds up and falls off gradually. Calculations using the multi-step load cycle described in the previous paragraph may also be performed for emergency overload cycles if desired.

7.1.2 Method of converting actual to equivalent load cycle

A transformer supplying a fluctuating load generates a fluctuating loss, the effect of which is about the same as that of an intermediate constant load for the same period of time. This is due to the heat storage characteristics of the materials in the transformer. A constant load that generates the same total losses as a fluctuating load is assumed an equivalent load from a temperature standpoint. Equivalent load for any part of a daily load cycle may be expressed by Equation (5).

$$\left[\frac{L_1^2 t_1 + L_2^2 t_2 + L_3^2 t_3 + \ldots\ldots + L_N^2 t_N}{t_1 + t_2 + t_3 + \ldots\ldots + t_N}\right]^{0.5} \tag{5}$$

where

L_1, L_2,… is various load steps in %, per unit, or in actual kVA or current

N is the total number of loads considered

t_1, t_2,... is the respective durations of these loads, h

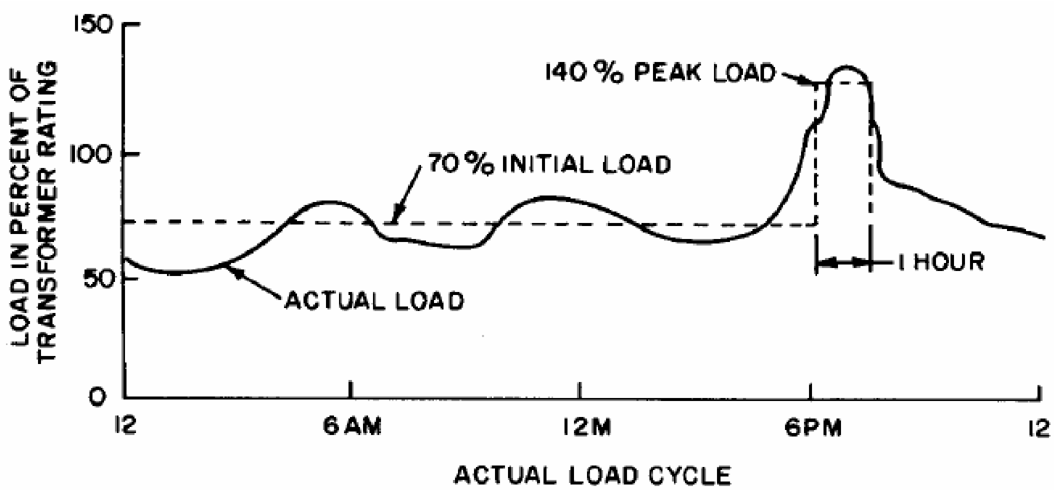


Figure 3—Example of actual load cycle and equivalent load cycle

7.1.3 Equivalent peak load

Equivalent peak load for the usual load cycle is the rms load obtained by Equation (5) for the limited period over which the major part of the actual irregular peak seems to exist. The estimated duration of the peak has considerable influence over the rms peak value. If the duration is over-estimated, the rms peak value may be considerably below the maximum peak demand. To guard against overheating due to high, brief overloads during the peak overload, the rms value for the peak load period should not be less than 90% of the integrated 1/2 h maximum demand.

7.1.4 Equivalent continuous prior load

The equivalent continuous prior load is the rms load obtained by Equation (5) over a chosen period of the day. Experience indicates that quite satisfactory results are obtained by considering the 12 h periods preceding and following the peak and by selecting the larger of the two rms values so produced. Time intervals (t) of 1 h are suggested as a further simplification of the equation, which for a 12 h period becomes Equation (6). The dashed line in Figure 3 shows the equivalent load cycle constructed from the actual load cycle.

$$\text{Equivalent continuous 12 h prior load} = 0.29\left[L_1^2 + L_2^2 + \ldots\ldots + L_{12}^2\right]^{0.5} \tag{6}$$

where

$L_1, L_2, \ldots$ is various load steps in %, per unit, or in actual kVA or current

7.2 Calculation of temperatures

7.2.1 General

The method given here for calculation of oil and winding temperatures for changes in load ~~is simplified and~~ requires no iterative procedures. The exponents, *m* and *n*, approximately account for changes in load loss and oil viscosity caused by changes in temperature. Values for the exponents used in these equations are shown in Table 4. Exact values of the exponents for specific transformers may be determined by overload test procedures in IEEE Std C57.119 [G6].[6]

An alternate method, which requires computer calculation procedures, is given in Annex G. This method is more exact in accounting for changes in load loss and oil viscosity caused by changes in resistance and oil temperature, respectively. The effect of a variable ambient temperature is also considered. This method should produce a greater accuracy in loading capability if accurate methods of determining load, ambient temperature, tap position, and the cooling mode in operation are utilized.

7.2.2 Components of temperature

The hottest-spot temperature is assumed to consist of three components given by the following equation:

$$\Theta_H = \Theta_A + \Delta\Theta_{TO} + \Delta\Theta_H \tag{7}$$

where

Θ_H is the winding hottest-spot temperature, °C

Θ_A is the average ambient temperature during the load cycle to be studied, °C

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C

$\Delta\Theta_H$ is the winding hottest-spot rise over top-oil temperature, °C

The top-oil temperature is given by the following equation:

$$\Theta_{TO} = \Theta_A + \Delta\Theta_{TO} \tag{8}$$

where

Θ_{TO} is the top-oil temperature, °C

Θ_A is the average ambient temperature during the load cycle to be studied, °C

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C

[6] The numbers in brackets combined with the letter "G" correspond to those of the bibliography in Annex G.

The temperature calculations assume a constant ambient temperature. The effect of a variable ambient may be conservatively considered as follows:

a) For ambient temperatures that increase during the load cycle, the instantaneous ambient should be used when considering load cycles.

b) For decreasing ambient temperatures, the maximum ambient during a long prior cycle of about 12 h should be used.

7.2.3 Top-oil rise over ambient

The top-oil temperature rise at a time after a step load change is given by the following exponential expression containing an oil time constant:

$$\Delta\Theta_{TO} = (\Delta\Theta_{TO,U} - \Delta\Theta_{TO,i})\left(1 - e^{-\frac{t}{\tau_{TO}}}\right) + \Delta\Theta_{TO,i} \tag{9}$$

where

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C

$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C

$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for $t = 0$, °C exp is the base of natural logarithm

τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h

For the two-step overload cycle with a constant equivalent prior load the initial top-oil rise is given by the following:

where

$\Delta\Theta_{TO,I}$ is the initial top-oil rise over ambient temperature for $t = 0$, °C

$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C

K_i is the ratio of initial load L to rated load, per unit

N is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.

R is the ratio of load loss at rated load to no-load loss on the tap position to be studied

For the multi-step load cycle analysis with a series of short-time intervals, Equation (9) is used for each load step, and the top-oil rise calculated for the end of the previous load step is used as the initial top-oil rise for the next load step calculation.

The ultimate top-oil rise is given by the following equation:

$$\Delta\Theta_{TO,U} = \Delta\Theta_{TO,R}\left[\frac{(K_U^2 R + 1)}{(R+1)}\right]^n \qquad (11)$$

where

$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C

$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C

K_U is the ratio of ultimate load L to rated load, per unit

n is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.

R is the ratio of load loss at rated load to no-load loss on the tap position to be studied

Equation (11) is used to calculate the ultimate oil rise for each load step. Except for very long duration constant loads, the ultimate top-oil rise calculated by Equation (11) is never reached.

7.2.4 Oil time constant

The thermal capacity is given by the following equation for the ONAN and ONAF cooling modes:

$$C = 0.1323 \text{ (weight of core and coil assembly in kilograms)} + 0.0882 \text{ (weight of tank and fittings in kilograms)} + 0.3513 \text{ (liters of oil)} \quad (12A)$$

or

$$C = 0.06 \text{ (weight of core and coil assembly in pounds)} + 0.04 \text{ (weight of tank and fittings in pounds)} + 1.33 \text{ (gallons of oil)} \quad (12B)$$

The derivation of the exponential heating equation is based on the average temperature rise of the lumped mass. In the case of the transformer this would be the average oil temperature. However, the top oil is the variable measured by temperature indicators or thermocouples during thermal tests. In Equation (12A) for the thermal capacity, two-thirds of the weight of the tank and 86% of the specific heat of the oil was used.

For forced-oil cooling modes either directed or non-directed the thermal capacity is given by the following:

$$C = 0.1323 \text{ (weight of core and coil assembly in kilograms)} + 0.1323 \text{ (weight of tank and fittings in kilograms)} + .5099 \text{ (liters of oil)} \quad (13A)$$

or

$$C = 0.06 \text{ (weight of core and coil assembly in pounds)} + 0.06 \text{ (weight of tank and fittings in pounds)} + 1.93 \text{ (gallons of oil)} \quad (13B)$$

For the calculation of the time constant, the weight of the tank and fittings to be used is only those portions that are in contact with heated oil. Some transformers may have cabinetry and tank base construction with substantial weight that does not contribute to the thermal mass in determination of the oil rise time constant.

The top-oil time constant at rated kVA is given by the following:

$$\tau_{TO,R} = \frac{C\,\Delta\Theta_{TO,R}}{P_{T,R}} \tag{14}$$

where

C is the thermal capacity of the transformer, W-h/°C

$P_{T,R}$ is the total loss at rated load, W

$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C

$\tau_{TO,R}$ is the time constant for rated load beginning with initial top-oil temperature rise of 0 °C, h

The top-oil time constant is

$$\tau_{TO} = \tau_{TO,R}\frac{\left(\dfrac{\Delta\Theta_{TO,U}}{\Delta\Theta_{TO,R}}\right) - \left(\dfrac{\Delta\Theta_{TO,i}}{\Delta\Theta_{TO,R}}\right)}{\left(\dfrac{\Delta\Theta_{TO,U}}{\Delta\Theta_{TO,R}}\right)^{\frac{1}{n}} - \left(\dfrac{\Delta\Theta_{TO,i}}{\Delta\Theta_{TO,R}}\right)^{\frac{1}{n}}} \tag{15}$$

where

n is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.

$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for $t = 0$, °C

$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C

$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C

τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h

$\tau_{TO,R}$ is the time constant for rated load beginning with initial top-oil temperature rise of 0 °C, h

In the derivation of Equation (9) it was assumed that the top-oil temperature rise $\Delta\Theta_{TO}$ is directly proportional to the heat loss q, or in equation form,

$$\Delta\Theta_{TO} = Kq^n$$

where

n is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.

K is the ratio of load L to rated load, per unit

q is the heat loss, W

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C

If the exponent n = 1.0, the time constant given by Equation (14) and the exponential Equation (9) is correct for any load and any starting temperature. If n is less than 1, the equation is incorrect and the time constant must be modified as shown in Equation (15) for different overload cycles. Equation (15) was developed to give a corrected time constant (for case of $n < 1$) to use in the exponential equation that gave the same rate of change of initial temperature rise and the same final temperature rise if the overload continued indefinitely; however, intermediate temperatures may vary somewhat from actual.

If n is equal to 1.0, 63% of the temperature change occurs in a length of time equal to the time constant regardless of the relationship of initial temperature rise and ultimate temperature rise. If n is not unity, the temperature change in a similar time interval will be different, depending on both initial temperature rise and ultimate temperature rise.

7.2.5 Winding hot-spot rise

Transient winding hottest-spot temperature rise over top-oil temperature is given by

$$\Delta\Theta_H = (\Delta\Theta_{H,U} - \Delta\Theta_{H,i})\left(1 - e^{-\frac{t}{\tau_w}}\right) + \Delta\Theta_{H,i} \tag{16}$$

where

t is the duration of load, h

$\Delta\Theta_H$ is the winding hottest-spot rise over top-oil temperature, °C

$\Delta\Theta_{H,U}$ is the ultimate winding hottest-spot rise over top-oil temperature for load L, °C

$\Delta\Theta_{H,i}$ is the initial winding hottest-spot rise over top-oil temperature for $t = 0$, °C

τ_W is the winding time constant at hot spot location, h

The initial hot-spot rise over top oil is given by

$$\Delta\Theta_{H,i} = \Delta\Theta_{H,R} K_i^{2m} \tag{17}$$

where

K_i is the ratio of initial load L to rated load, per unit

m is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See Table 4.

$\Delta\Theta_{H,i}$ is the initial winding hottest-spot rise over top-oil temperature for $t = 0$, °C

$\Delta\Theta_{H,R}$ is the winding hottest-spot rise over top-oil temperature at rated load on the tap position to be studied, °C

The ultimate hot-spot rise over top oil is given by

$$\Delta\Theta_{H,U} = \Delta\Theta_{H,R} K_u^{2m} \tag{18}$$

where

K_U is the ratio of ultimate load L to rated load, per unit

m is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of *m* has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See Table 4.

$\Delta\Theta_{H,U}$ is the ultimate winding hottest-spot rise over top-oil temperature for load L, °C

$\Delta\Theta_{H,R}$ is the winding hottest-spot rise over top-oil temperature at rated load on the tap position to be studied, °C

The rated value of hot-spot rise over top oil is given by

$$\Delta\Theta_{H,R} = \Delta\Theta_{H/A,R} - \Delta\Theta_{TO,R} \tag{19}$$

where

$\Delta\Theta_{H/A,R}$ is the winding hot spot rise over ambient at rated load on the tap position to be studied, °C

$\Delta\Theta_{H,R}$ is the winding hottest-spot rise over top-oil temperature at rated load on the tap position to be studied, °C

$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C

The value of the winding hot-spot rise over ambient $\Delta\Theta_{H/A,R}$ is obtained in the following manner, in order of preference:

– By actual test using imbedded detectors

– Calculated value supplied by manufacturer on test report, or

– Assume $\Delta\Theta_{H/A,R}$ = 80 °C for 65 °C average winding rise and 65 °C for 55 °C average winding rise

The value of the top-oil rise over ambient $\Delta\Theta_{TO,R}$ is determined by

– Actual test per IEEE Std C57.12.90, or

– Calculated value supplied by the manufacturer on the test report

The winding time constant is the time it takes the winding temperature rise over oil temperature rise to reach 63.2% of the difference between final rise and initial rise during a load change. The winding time constant may be estimated from the resistance cooling curve during thermal tests or calculated by the manufacturer using the mass of the conductor materials. The winding time constant varies with the oil viscosity and the exponent *m*. For moderate overloads it is conservative to neglect the winding time constant and assume the winding hot-spot rise over top oil is given by Equation (18).

7.2.6 Exponents for temperature rise equations

The suggested exponents for use in the temperature rise equations are given in Table 4.

Table 4—Exponents used in temperature determination equations

Type of cooling	***m***	***n***
ONAN	0.8	0.8
ONAF	0.8	0.9
Non-directed OFAF or OFWF	0.8	0.9
Directed ODAF or ODWF	1.0	1.0

'Other values of exponents may be used if substantiated by design and test data.

7.2.7 Adjustment of test data for different tap position

If it is desired to adjust the test report data for operation on a no-load tap position other than that reported on the test report, the following equations may be used. The prime symbol (') indicates values at the different tap position.

Top-oil rise over ambient:

$$\Delta \Theta'_{TO,R} = \Delta \Theta_{TO,R} \left[\frac{P'_{T,R}}{P_{T,R}} \right]^n \tag{20}$$

where

n is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.

$P_{T,R}$ is the total loss at rated load, W

$P'_{T,R}$ is the total loss at rated load on a different tap position, W

$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C

$\Delta\Theta'_{TO,R}$ is the top-oil rise over ambient temperature at rated load on a different tap position, °C

Hottest spot rise over top oil:

$$\Delta\Theta'_{H,R} = \Delta\Theta_{H,R}\left[\frac{I'_R}{I_R}\right]^{2m} \tag{21}$$

where

I_R is rated current

I'_R is rated current for a different tap position

m is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See Table 4.

$\Delta\Theta_{H,R}$ is the winding hottest-spot rise over top-oil temperature at rated load on the tap position to be studied, °C

$\Delta\Theta'_{H,R}$ is the winding hottest-spot rise over top-oil temperature at rated load on a different tap position, °C

Time constant at rated load:

$$\tau'_{TO,R} = \frac{C\,\Delta\Theta_{TO,R}}{P'_{T,R}} \qquad (22)$$

where

C is the thermal capacity of the transformer, W-h/°C

$P'_{T,R}$ is the total loss at rated load on a different tap position, W

$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C

$\tau'_{TO,R}$ is the time constant for rated load for a different tap position beginning with initial top-oil temperature rise of 0 °C, h

7.3 Computer calculation of loading capability

Due to the wide variations in transformer characteristics typical loading capability tables are not published in this guide. The equations given in Clause 5 and Clause 7 may be used to develop a computer program that calculates the loading capability for a specific transformer design~~,~~. A suggested flow chart is shown in Table 4. The program should compute and print the maximum peak load that can be impressed on a transformer and meet specified limitations. In addition, the computer program should calculate the top-oil and hottest-spot temperatures as a function of time for a repetitive 24 h load cycle. The total loss of insulation life for a 24 h load cycle should also be calculated.

Input to the program should consist of the following:

a) Transformer characteristics (loss ratio, top-oil rise, bottom-oil rise, hottest-spot rise, total loss, gallons of oil, weight of tank and fittings) (all at rated load)

b) Ambient temperatures

c) Initial continuous load

d) Peak load durations and the specified daily percent loss of life

e) Repetitive 24 h load cycle if desired

A systematic convergence process may be used to obtain the highest allowable peak load. An initial trial is made with an assumed peak load midway between the minimum continuous load and maximum permitted peak load (300% for distribution transformers, 200% for power transformers). Using this peak load, aging calculations are made at varying time intervals (depending on the time duration of the peak load) during the 24 h, to determine the total daily insulation aging imposed by the load cycle. A comparison is made between the calculated values and the limiting values, (top-oil temperature, hot-spot temperature, or specified percent loss of life). Depending on the results, the peak value is changed and the calculation repeated until the calculated value of the total percent loss of life above normal is within ±4% of the desired value. At this point, the peak load and corresponding values of peak hottest-spot temperature, peak top-oil temperature, total percent loss of life, and the specified percent loss of life are printed out.

7.4 Bibliography for Clause 7

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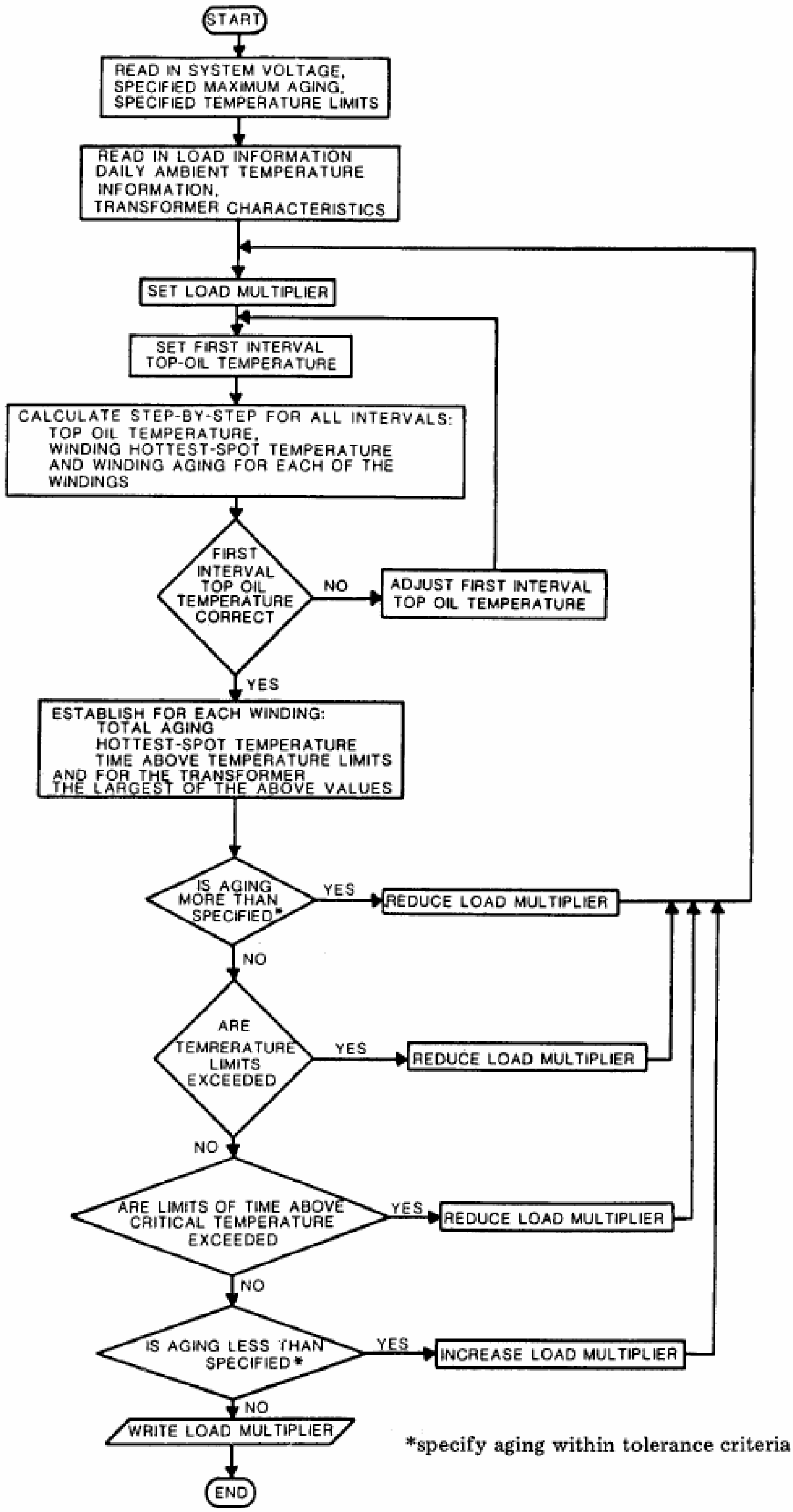


Figure 4 —Logic diagram for computer program

8. Loading of distribution transformers and step-voltage regulators

8.1 Life expectancy

8.1.1 General

Distribution transformer and voltage regulator life expectancy at any operating temperature is not accurately known. The information given regarding loss of insulation life at elevated temperatures is considered to be conservative and the best that can be produced from present knowledge of the subject. The effects of temperature on insulation life are being investigated continuously, and new data may affect future revisions of this guide. The word conservative as used above is used in the sense that the expected loss of insulation life for a single overload cycle will not be greater than the amount stated.

Because the cumulative effects of temperature and time in causing deterioration of ~~transformer~~ insulation are not thoroughly established, it is not possible to predict with any great degree of accuracy the length of life of a transformer even under constant or closely controlled conditions, much less under widely varying service conditions. Deterioration of insulation is generally characterized by a reduction in mechanical strength and in dielectric strength, but these characteristics may not necessarily be directly related. In some cases, insulation in a charred condition will have sufficient insulating qualities to withstand normal operating electrical and mechanical stresses. A transformer or voltage regulator having insulation in this condition may continue in service for many months or even years, if undisturbed. On the other hand, any unusual movement of the conductors, such as may be caused by expansion of the conductors due to heating resulting from a heavy overload or to large electromagnetic forces resulting from short circuit, may disturb the mechanically weak insulation such that turn-to-turn or layer-to-layer failure will result.

The recommendations of this guide are based upon the life expectancy curve of Figure 1, which relates to the insulation system, but does not account for such factors as deterioration of gaskets, rusting of tanks, etc., that are induced by exposure to the elements of the weather in normal operations.

8.1.2 Normal life expectancy

The basic loading of a distribution transformer or voltage regulator for normal life expectancy is continuous loading at rated output when operated under usual service conditions as indicated in 4.1 of IEEE Std C57.12.00-~~1993.~~2010 and 4.1 of IEEE Std C57.15-2009. It is assumed that operation under these conditions is equivalent to operation in a constant 30 °C ambient temperature. The hottest-spot conductor temperature is the principal factor in determining life due to loading. Direct temperature measurement of the hottest-spot may not be practical on commercial designs. The indicated hottest-spot temperatures have therefore been obtained from tests made in the laboratory and mathematical models. The hottest-spot temperature at rated load is the sum of the average winding temperature and a hottest-spot allowance, usually 15 °C. Normal life expectancy will result from operating continuously with hottest-spot conductor temperature of 110 °C or an equivalent daily transient cycle. For mineral oil-immersed transformers and voltage regulators operating continuously under the foregoing conditions this temperature has been limited to a maximum of 110 °C. Normal life expectancy of transformer and voltage regulator insulation using different criteria is given in Table 1. Distribution and power transformer model tests indicate that the normal life expectancy at a continuous hottest-spot temperature of 110 °C is 20.55 years.

8.2 Limitations

8.2.1 General

When loading distribution transformers and voltage regulators above nameplate rating, other limitations may be encountered. Among these limitations are oil expansion, pressure in sealed units, and the thermal capability of bushings; leads, tap changers, or associated equipment such as cables, reactors, circuit breakers, fuses, disconnecting switches, and current transformers. Any of these items may limit the loading to less than the capability of the winding insulation. Manufacturers should, therefore, be consulted before loading transformers or voltage regulators above nameplate rating. Operation at hottest-spot temperatures above 140 °C may cause gassing in the solid insulation and the oil. Gassing may produce a potential risk to the dielectric strength integrity of the transformer or voltage regulator and this risk should be considered when the guide is applied.

Distribution transformers are sometimes installed in subsurface manholes and vaults of minimum size with natural ventilation through roof gratings. This type of installation results in a higher ambient temperature than the outdoor air. The amount of increase depends on the design of the manholes and vaults, net opening area of the roof gratings, and the adjacent subsurface structures. Therefore, the increase in effective ambient temperature for expected transformer losses must be determined before loading limitations can be estimated.

The separate heating effects of loading a distribution transformer or voltage regulator, and of solar radiation, may each result in an enclosure surface temperature high enough to present a hazard to personnel who might come in contact with the enclosure surface where unlimited access to the transformer or voltage regulator exists (such as certain pad-mounted units).

8.2.2 Limitations for loading distribution transformers above nameplate rating

Suggested limits of temperature or load for loading distribution transformers above the nameplate rating are given in Table 5 (note the above discussion on hottest-spot temperatures in excess of 140 °C).

Table 5—Suggested limits of temperature or load for loading above nameplate distribution transformers with 65 °C rise

Top-oil temperature	120 °C
Hottest-spot conductor temperature	200 °C[a]
Short-time loading (1/2 h or less)	300%

[a] See discussion on hottest-spot temperatures in excess of 140 °C in 8.2.1.

8.3 Types of loading

8.3.1 Loading for normal life expectancy under specific conditions

Distribution transformers and voltage regulators may be operated above 110 °C average continuous hottest-spot temperature for short periods provided they are operated for much longer periods at temperatures below 110 °C. This is due to the fact that thermal aging is a cumulative process. This permits loads above the rating to be safely carried under specified conditions without encroaching upon the normal life expectancy of the transformer and voltage regulator. When the ambient temperature is below the 30 °C ambient used to establish the transformer's or voltage regulator's rating, or when the transformer's temperature rises at nameplate rated load, as determined by test, are less than the normal limiting values, some additional load beyond nameplate rating is possible within normal life expectations.

8.3.2 Loading by top-oil temperature

Top-oil temperature alone should not be used as a guide for loading transformers and voltage regulators. The hottest-spot winding rise over top-oil temperature at full load should be determined from the factory tests corrected for the actual load carried by using Equation (18). This hottest-spot rise over top-oil, subtracted from 110 °C, will give the maximum permissible top-oil temperature for normal life expectancy. It should be recognized that, due to the thermal lag in the oil temperature rise, time is required for a transformer or voltage regulator to reach a stable temperature for any change in load. Therefore, higher peak loads may be carried for a short duration. If the transformer or voltage regulator characteristics are not accurately known, maximum top-oil temperatures derived from Figure 5 may be used as an approximate guide. Figure 5 is based on a difference between hottest-spot temperature and top-oil temperature of 25 °C at rated load.

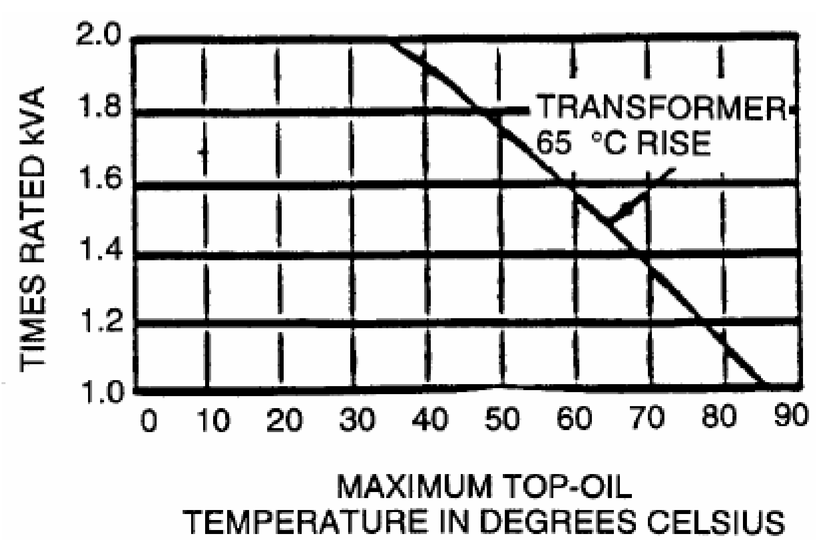
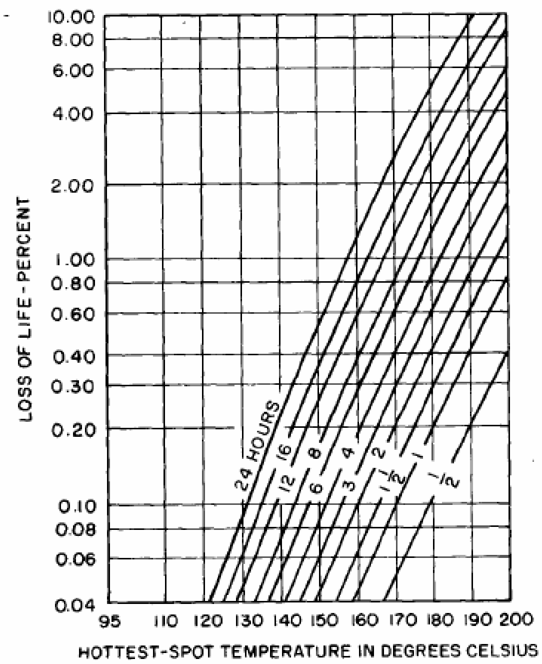


Figure 5— Approximate continuous loading for normal life expectancy based on maximum top-oil temperature



Time (h)	0.05	0.10	0.25	%loss of life[a] 0.50	1.00	2.00	4.00
1/2	171	180	193	204[b]			
1	161	171	183	193	204[b]		
2	153	161	174	183	193	204[b]	
4	144	153	164	174	183	193	204[b]
8	136	144	155	164	174	183	193
16	128	136	147	155	164	174	183
24	124	131	142	150	159	168	178

[a] Calculated for one occurrence on the assumption that the hottest-spot temperature remains constant for the specified time duration. For loss of life determinations in which the time-temperature response of the transformer is taken into account, refer to clauses 5 and 7.
[b] Maximum permissible value is 200 °C; the underlined values permit interpolation.

Figure 6 —Loss of life expectancy (based on a normal life of 180 000 h)

8.3.3 Continuous loading based on average winding test temperature rise

For each degree Celsius in excess of 5 °C that the average winding test temperature rise is below 65 °C, the transformer or voltage regulator load may be increased above rated kVA by 1.0%. The 5 °C margin is taken to provide a tolerance in the measurement of temperature rise. The load value thus obtained is the kVA load, which the transformer or voltage regulator can carry at 65 °C rise. Since this may indicate a load capability beyond that contemplated by the designer, the limitations given in 8.2 should be checked before taking full advantage of this increase.

The above is not applicable to all distribution transformers and voltage regulators. Some transformers are designed to have the difference between the hottest-spot and average winding temperatures greater than the ~~15 C allowance. This will result in an average winding temperature rise of less than 65 C, while the hottest-spot winding rise may be at the 80 C limiting value. This condition may exist in transformers with large differences between top and bottom oil temperatures. The manufacturer should be consulted for information on the hottest-spot allowance used for these designs.~~ 15 °C allowance. This will result in an average winding temperature rise of less than 65 °C, while the hottest-spot winding rise may be at the 80 °C limiting value. This condition may exist in transformers and voltage regulators with large differences between top and bottom-oil temperatures. The manufacturer should be consulted for information on the hottest-spot allowance used for these designs.

8.3.4 Short-time loading with moderate sacrifice of life expectancy (operation above 110 °C hottest- spot temperature)

When for any given period of time the aging effect of one overload cycle or the cumulative aging effect of a number of overload cycles is greater than the aging effect of continuous operation at rated load, the insulation deteriorates at a faster rate than normal. The rate of deterioration is a function of time and temperature and is commonly expressed as a percentage loss of life per incident. A chart and table showing relative loss of life for various combinations of time and temperature are given in Figure 6 for 65 °C rise transformers and voltage regulators.

It should be clearly understood that, while the insulation aging rate information is considered to be conservative and helpful in estimating the relative loss of life due to loads above nameplate rating under various conditions, this information is not intended to furnish the sole basis for calculating the normal life expectancy of transformer and voltage regulator insulation. The uncertainty of service conditions and the wide range in ratings covered should be considered in determining a loading schedule. Some of the variables are wide differences in ambient temperature between localities; differences in elevation; restricted air circulation caused by buildings, fire walls, etc.; previous emergency loading history that may not be known to the operator; and variations in design characteristics. As a guide, many users consider an average loss of life of 4% per day in any one emergency operation to be reasonable.

8.4 Loading specific to voltage regulators

8.4.1 General

Most voltage regulators are 55 °C rise products and of sealed construction, using thermally upgraded paper insulation. Some voltage regulator nameplates show both 55 °C and 65 °C ratings with a 1.12 factor in the kVA rating for the higher rise units. The tap changer is integral to the regulator and usually is the critical factor in establishing the loading limits. Contact life is significantly affected by loading practices.

Regulators are thermally designed and nameplate rated for operation continuously at the extreme raise and lower tap positions. According to IEEE Std C57.15, regulators may be continuously loaded, in discretely defined increments, above that rating if the tap position range is restricted. This factor differs for single-phase and three-phase regulators.

Most regulators are designed for application at multiple nominal system voltages but one specific load rating.

8.4.2 Restricted regulation

Many step-voltage regulators are adjusted to step voltages up or down less than their maximum design amount. When step-voltage regulators have restricted voltage ranges, less series winding is in the circuit and the load current in the shunt winding is less than at the full range of regulation.

The manufacturer should be consulted for his recommendation concerning additional load current that can be carried when the voltage range is restricted. Limitations indicated in 8.2.1 may affect the maximum loads indicated in Table 6, which gives an approximate guide for restricted range application. The loads given in Table 6 will give a normal life expectancy.

Table 6—Loading with reduced regulation (based on ± 10 % range)

Limiting regulating range %	Load (% of rated load)
± 10	100
± 8 ¾	110
± 7 ½	120
± 6 ¾	135
± 5	160

8.4.3 Loading with reduced voltages

Step-voltage regulators are sometimes applied to systems operating at voltages below their nameplate rating. Under these conditions, the percent regulation remains the same.

The load current rating does not change; however, the kVA rating and the kVA being controlled are both reduced in proportion to the voltage being used for most voltage ratings. The only exception is 7620 volt rating. This voltage rated regulator will commonly be applied at the lower voltage of 7200 volts.

8.4.4 Limitations for loading voltage regulators above nameplate rating

Suggested limits of temperature and load for loading above the nameplate rating are given in Table 7.

Table 7—Suggested limits of temperature and load for loading above nameplate voltage regulators with 55 °C or 65 °C Rise

Description	55 °C	65 °C
Top Oil Temperature	100 °C	110 °C
Hottest Spot Conductor Temperature	180 °C	180 °C
Short Time Loading (1/2 hour or less)	200%	200%

9. Loading of power transformers

9.1 Types of loading and their interrelationship

Power transformer life expectancy at various operating temperatures is not accurately known, but the information given regarding loss of insulation life at elevated temperature is the best that can be produced from present knowledge of the subject. Loads in excess of nameplate rating may subject insulation to temperatures higher than the basis of rating definition. To provide guidance on risk associated with higher operating temperature, four different loading conditions beyond nameplate have been ~~defined.~~ developed as examples, and are used throughout this guide. The time and temperature limits shown in Table 9 to explain the basis of these examples, are appropriate for the system development and system operations philosophy of some transformer owner companies. Other companies have developed and use other limits that are consistent with their philosophies. These may be the same limits as shown in Table 8. (For example: loading guides developed by some Independent System Operators (ISOs) have always used the limits in Table 8, and continue to do so.) This guide recommends that each transformer owner develop and use the limits that are consistent with their operational philosophy. An increased risk is probable for each successive loading with its attendant increased temperature. For each higher temperature, a higher risk loading condition can be assumed to be additive to any lower risk condition accepted by the user except for the short-time emergency loading. The four types of loading are as follows:

Normal life expectancy

a) Normal life expectancy loading

Sacrifice of life expectancy

b) Planned loading beyond nameplate
c) Long time emergency loading
d) Short time emergency loading

Examples of loads that fall in these categories are illustrated in Figure 7.

9.2 Limitations

9.2.1 Temperature or load limitations

Suggested limits of temperatures or loads for loading above nameplate rating are given in Table 8. Suggested limits of temperature which give reasonable loss of life for the four types of loading are given in Table 9.

Table 8—Suggested limits of temperature or load for loading above nameplate power transformers with 65 °C rise

Top-oil temperature	110 °C
Hottest-spot conductor temperature	180 °C
Maximum loading	200%

Table 9— Maximum temperature limits used in the examples in this guide

	Normal life expectancy loading	Planned loading beyond nameplate rating	Long-time emergency loading	Short-time emergency loading
Insulated conductor hottest-spot temperature, °C	120 [a]	130	140	180 [b]
Other metallic hot-spot temperature (in contact and not in contact with insulation), °C	140	150	160	200
Top-oil temperature,°C	105	110	110	110

[a] 110 °C on a continuous 24 h basis (80 °C winding hottest spot rise over a 40 °C maximum ambient).

[b] Gassing may produce a potential risk to the dielectric strength of the transformer. This risk should be considered when this guide is applied refer to Annex A.

[c] The time and temperature limits shown in Table 9 to develop the examples, are appropriate for the system development and system operations philosophy of some companies. Other companies have developed and use other limits that are consistent with their philosophies.

Usually the limits of hot-spot temperature for other metallic parts not in contact with insulation are design limits and calculated by the manufacturer when an overload specification is submitted as part of the purchasing specifications.

9.2.2 Ancillary components

Tap changers bushings, leads, and other ancillary equipment may restrict loading to levels below those calculated by the equations in Clause 7 or Annex G. The user may wish to specify that ancillary equipment not restrict loading to levels below those permitted by the insulated conductor and other metallic part hot spots. Additional information on loading of ancillary components is given in Annex B.

9.2.3 Risk considerations

Normal life expectancy loading is considered to be risk free; however, the remaining three types of loading have associated with them some indeterminate level of risk. Specifically, the level of risk is based on the quantity of free gas, moisture content of oil and insulation, and voltage. The presence of free gas as discussed in Annex A may cause dielectric failure during an overvoltage condition and possibly at rated power frequency voltage. The temperatures shown in Table 9 for each type of loading are believed to result in an acceptable degree of risk for the special circumstances that require loading beyond nameplate rating. A scientific basis for the user's evaluation of the degree of risk is not available at this time. Current research in the area of model testing has not established sufficient quantitative data relationships between conductor temperature, length of time at that temperature, and reduction in winding dielectric strength. Additionally, there are other important factors that may affect any reduction, such as moisture content of the winding insulation and rate of rise of conductor temperature.

9.3 Normal life expectancy loading

9.3.1 General

The basic loading of a power transformer for normal life expectancy is continuous loading at rated output when operated under usual conditions as indicated in 4.1 of IEEE Std C57.12.00-2010. It is assumed that the operation under these conditions is equivalent to operation in an average ambient temperature of 30 °C for cooling air or 25 °C for cooling water. Normal life expectancy will result from operating with a continuous hottest-spot conductor temperature of 110 °C (or equivalent variable temperature with 120 °C maximum in any 24 h period). The 110 °C hottest-spot temperature is based on the hottest-spot rise of 80 °C plus the standard average ambient temperature of 30 °C.

Transformers may be operated above 110 °C hottest-spot temperature for short periods providing they are operated for much longer periods at temperatures below 110 °C. This is due to the fact that thermal aging is a cumulative process and thus permits loads above the rating to be safely carried under many conditions without encroaching upon the normal life expectancy of the transformer. The equations given in Clause 7 or Annex G may be used to calculate the hottest-spot and top-oil temperatures as a function of load for normal life expectancy.

9.3.2 Influence of ambient temperature on normal life expectancy loading

The influence of ambient temperature on normal life expectancy loading is given in Clause 6.

9.3.3 Normal life expectancy loading by top-oil temperature

Top-oil temperature alone should not be used as a guide for loading power transformers. The hottest-spot to top-oil gradient at full load should be determined from factory tests or, lacking data a value should be assumed. The full load hottest-spot to top-oil gradient should be corrected to that for actual load using Equation (18). The gradient subtracted from 110 °C will give the maximum permissible oil temperature for normal life expectancy. It should be recognized that, due to thermal lag in oil rise, time is required for a transformer to reach a stable temperature following any change in load.

9.3.4 Normal life expectancy loading by average winding test temperature rise

For each 1 °C in excess of 5 °C that the average winding test temperature is below 65 °C, the transformer load may be increased above rated load by the percentages given in Table 3. A 5 °C margin is used to provide a tolerance in the measurement of temperature rise. The load thus obtained is that which the transformer can carry at 65 °C rise. Since this may increase the loading beyond that contemplated by the designer, the limitations given in Table 8 and Table 9 should be checked before taking full advantage of this increased load capability.

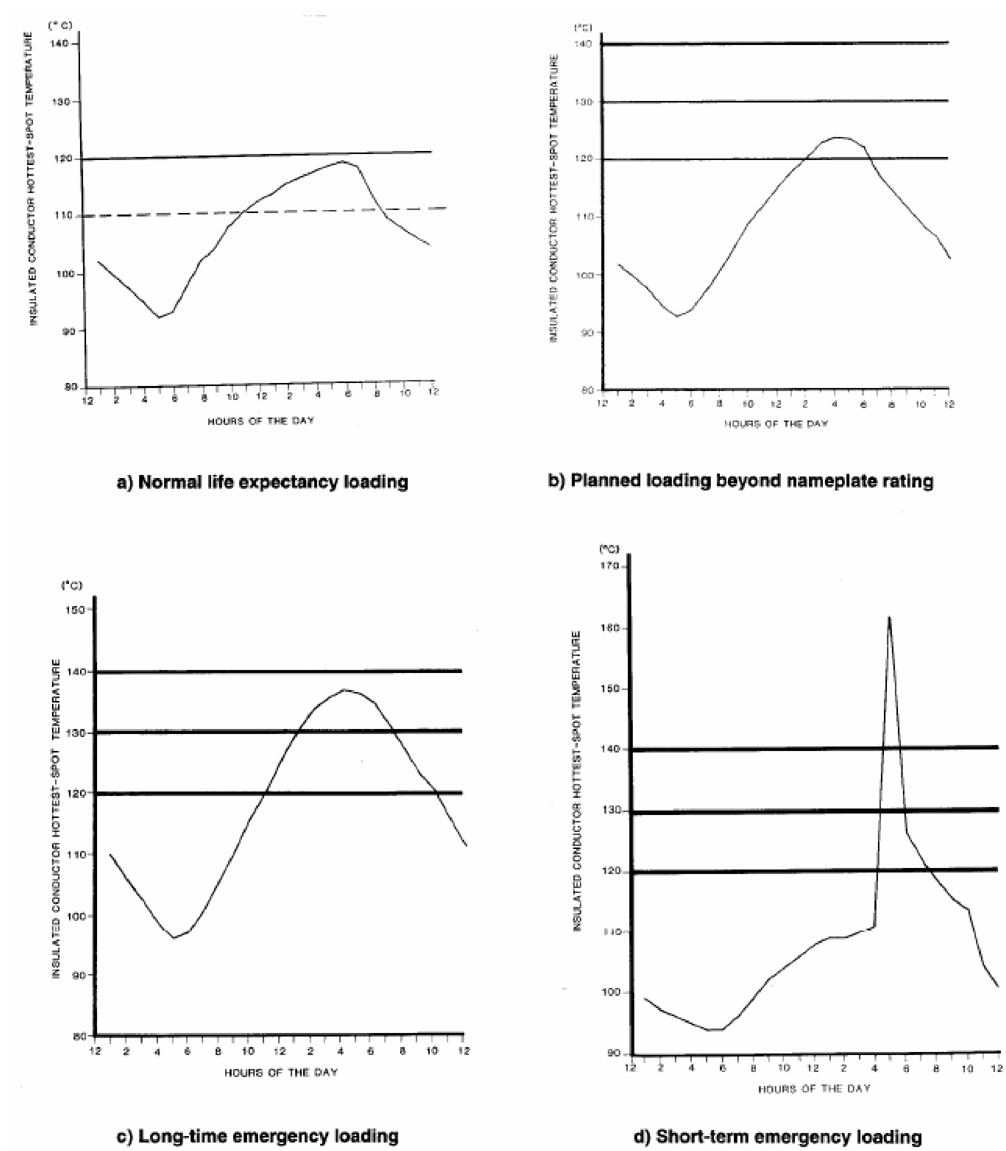


Figure 7— Typical load cycles for the examples ~~Types of loading~~

Some power transformers are designed to have the difference between the hottest-spot and average conductor temperature greater than 15 °C. This will result in an average winding temperature rise less than 65 °C, but the hottest-spot winding temperature rise may be the limiting value of 80° C. Such transformers should not be loaded above their rating by using Table I.2. The manufacturer should be consulted for information on the hottest-spot allowances used for these designs. This condition may exist in transformers with large differences (greater than 30 °C) between top and bottom oil temperatures and may be checked approximately by measuring the top and bottom radiator temperatures. Whenever possible, data on hottest- spot and oil temperatures obtained from factory temperature tests should be used in calculating transformer load capability or when calculating temperatures for loads above rating.

9.4 Planned loading beyond nameplate rating

Planned loading beyond nameplate rating results in either the conductor hottest-spot or top-oil temperature exceeding those suggested in Table 9 for normal life expectancy loading, and is accepted by the user as a normal, planned repetitive load. Usually planned loading beyond nameplate rating is restricted to transformers that do not carry a continuous steady load. Suggested conductor hottest-spot temperatures are presented in Table 9. Planned loading beyond nameplate rating example is a scenario wherein a transformer is so loaded that its hottest-spot temperature is in the temperature range of 120 °C–130 °C. The length of time for a transformer to operate in the 120 °C–130 °C range should be determined by loss of insulation life calculations, taking into account the specific load cycle. The characteristics of this type of loading are no system outages, regular and comparatively frequent occurrences, and life expectancy is less than for loading within the nameplate rating.

9.5 Long-time emergency loading

Long-time emergency loading results from the prolonged outage of some system element and causes either the conductor hottest-spot or the top-oil temperature to exceed those suggested for planned loading beyond nameplate rating. This is not a normal operating condition, but may persist for some time. It is expected that such occurrences will be rare. Long-time emergency loading may be applied to transformers carrying continuous steady loads, but loss of insulation life must be determined to be acceptable. Suggested conductor hottest-spot temperatures are presented in Table 9. Top-oil temperature should not exceed 110 °C at any time.

Long-time emergency loading example is a scenario wherein a power transformer is so loaded that its hottest-spot temperature is in the temperature range of 120 °C–140 °C. The characteristics of this type of loading are one long-time outage of a transmission system element, two or three occurrences over the normal life-time of the transformer where each occurrence may last several months, and the risk is greater than planned loading beyond nameplate rating. Figure 7c) illustrates an example of a long-time emergency loading profile. The hottest-spot temperature for this example exceeds 120 °C. Calculations should be made to determine if the loss of insulation life is acceptable for the specific load cycle.

9.6 Short-time emergency loading

Short-time emergency loading is an unusually heavy loading brought about by the occurrence of one or more unlikely events that seriously disturb normal system loading and cause either the conductor hottest- spot or top-oil temperature to exceed the temperature limits suggested for planned loading beyond name- plate rating. Acceptance of these conditions for a short time may be preferable to other alternatives. Suggested conductor hottest-spot temperatures are presented in Table 9. Top-oil temperature should not exceed 110 °C at any time. This type of loading, with its greater risk, is expected to occur rarely.

Short-time emergency loading example is a scenario wherein a transformer is so loaded that its hottest-spot temperature is as high as 180 °C for a short time. The characteristics of this type of loading are a series of unlikely conditions on the transmission system (second or third contingency), one or two occurrences over the normal lifetime of the transformer, and the risk is greater than for long-time emergency loading. Calculations should be made to determine if the loss of insulation life during the short-time emergency is acceptable for the specific load cycle. Figure 7d) illustrates an example of a short-time emergency loading profile. This figure presents a temperature curve that had leveled off for the day until about 4 p.m. when a system condition occurs that loads the transformer so that its hottest-spot temperature rises rapidly to 163 °C in 1 h.

9.7 Loading information for specifications

If the maximum load capacity that a transformer user plans to utilize on a planned or emergency basis is included in the specifications at the time of purchase, the following information should be given:

a) Load

1) Two step load cycle approach

Prior steady-state load, percent of maximum nameplate rating

– Maximum load, percent of maximum nameplate rating

– Duration

2) Load cycle over a 24 h period b)

Ambient temperature, °C

1) Constant for load cycle approach [see item a)1)]

2) Variable over the load cycle for load cycle approach [see item a)2)]

c) Type of loading, planned or emergency, long-time or short-time d)

Limiting top-oil temperature

e) Limiting hottest-spot temperature

f) Statement that ancillary components not limit the loading capability

More than one set of loading conditions may be used. The load cycle with limiting top-oil and hottest-spot temperatures determine loss of life, which may be calculated.

9.8 Operation with part or all of the cooling out of service

When auxiliary equipment, such as pumps or fans, or both, is used to increase the cooling efficiency, the transformer may be required to operate for some time without this equipment functioning. The permissible loading under such conditions is given in Annex H.

Annex A

(normative)

Thermal evolution of gas from transformer insulation

A.1 General

A new bubble generation model was developed by Oommen outlined in EPRI reports EL 6761 [A7][7] and EL 7291 [A8] in March 1990 and March 1992 respectively. This is the basis of Equation (7) in Clause 7. The new model used realistic coil segments to produce bubbles under overload conditions.

An earlier model (see Fessler [A9] and McNutt, Rouse, and Kaufman [A22]) given in Annex A of the 1995 version of IEEE Std C57.91 was developed purely from physical and chemical considerations regarding bubble generation based on vapor pressure computations and the gas content of oil. It had been assumed in that model that the condition for generation of a bubble was that the total gas/vapor pressure contribution exceeds the external pressure exerted on the bubble. The total gas/vapor pressure contribution was computed from the gas content of the bubble (from mostly dissolved nitrogen and some generated gases) and from water vapor released by heat from paper insulation in contact with the hot conductor. The bubbles in an initially degassed system (as in sealed transformers with conservators) would mostly consist of water vapor. It was argued that in a nitrogen saturated system, the bubbles would contain mostly nitrogen, and the balance would be from water vapor and generated gases. These assumptions led to the conclusion that in a gas saturated system bubbles would be formed much earlier than in a conservator system because only a small increase in temperature would be needed to release sufficient water vapor. It was estimated that the bubble evolution temperature in a gas saturated system would be as much as 50 °C lower than the bubble evolution temperature in a conservator system.

A complete re-evaluation of the basic assumptions and experimental methods to verify bubble evolution was conducted in the new study. The significant findings are given below.

~~In order for a bubble to form and grow within a liquid, the gas within the bubble must develop an internal pressure sufficient to overcome the forces constraining it, namely, the interfacial tension force of the liquid, the gravitational force resulting from the column of liquid above the bubble, and the force from whatever atmospheric pressure is acting on the surface of the liquid. Considering the formation of a bubble within the mineral oil of a transformer, only the last two forces merit practical consideration. The source of the gas~~

~~pressure within the liquid, which tends to form a potential bubble, is the summation of partial pressures exerted by various individual gases dissolved in the liquid. If there is a gas space over the free surface of the liquid, the partial pressures of the dissolved gases within the liquid is in balance with the partial pressures of the same gases in the gas space under equilibrium conditions.~~

~~The principal gases found dissolved within the mineral oil of a transformer are the following:~~

~~Nitrogen: From the external atmosphere or from a gas blanket over the free surface of the oil~~ ~~Oxygen: From the external atmosphere~~

~~Water: From moisture absorbed in cellulose insulation or from thermal decomposition of the cellulose~~

~~Carbon dioxide: From thermal decomposition of cellulose insulation~~

~~Carbon monoxide: From thermal decomposition of cellulose insulation~~

~~Other gases may be present in very small amounts as a result of oil or insulation decomposition by overheated metal, partial discharges, or arcing and sparking, but these normally make an insignificant contribution to the summation of gas partial pressures within the oil.~~

~~References [A5] and [A18][4] describe a mathematical modelling technique by which it is possible to make a quantitative analysis of the tendency for bubble formation in an operating transformer. The mathematical model is oriented around a physical model of the hottest-spot conductor within the transformer. That physical model is shown in figure A.1. The analysis centers around the gas pressure generated in the "local oil," which impregnates the innermost wrap of paper insulation at the conductor surface. Because the local oil is in intimate contact with the conductor, it is realistic to assume that the oil temperature closely tracks the conductor temperature. Also, as a result of the additional external wraps of paper, it is realistic to assume that the local oil and the paper wrap that it impregnates constitute a small isolated system whose total gas content must remain essentially constant during a thermal transient lasting for no more than a few hours (except for the possible formation of additional thermal decomposition gases from the heated cellulose). One final assumption is that the paper insulation of the inner wrap serves as an infinite water reservoir for the local oil, since the moisture holding capability of the cellulose is at least two orders of magnitude greater than the impregnating oil. The consequence of this last assumption is that the partial pressure of water in the local oil is always determined by the moisture content of the inner paper wrap.~~

~~Water vapor pressure equilibrium data for paper insulation and mineral oil are available in the published literature, although the paper from which the data was derived was not thermally upgraded, and the full range of operating temperatures into the overload region was not explored. The characteristic used in 18 is reproduced in figure A.2, showing extrapolation of the data to 180 C. This graph makes it possible to relate the partial pressure of water vapor in the local oil to the moisture content of the inner wrap of conductor insulation.~~

~~[4]The numbers in brackets correspond to bibliographic items. Other gases of interest will have concentrations in the bulk oil during normal operating conditions, which will come into equilibrium with the concentrations in the local oil over a period of time. During the thermal excursion of an overload event, these concentrations cannot change appreciably, but the resultant partial pressures generated by the gases will change with temperature. The fashion in which the gas concentration in the oil and its partial pressure is related is described by Henry's Law, which can be written mathematically as follows:~~

The fundamental equation governing bubble formation is

$$P_{int.} = P_{ext.} + (2\sigma / R_B) \quad \text{(A.1)}$$

Where

P_{int} = internal pressure
P_{ext} = external pressure
R_B = Radius of bubble
σ = Surface tension

The second term on the right is the surface tension pressure. In the previous model, the second term had *been* completely ignored. However, this term has great significance for a micro bubble. As R_B becomes smaller and smaller, the second term would carry more and more weight, and may exceed the first term. This would imply that the surface tension pressure would force the collapse of a micro bubble. So the assumption that a visible bubble is formed by the growth of a micro bubble is not theoretically sound.

How then is a bubble formed? Experts agree that a bubble is formed by the expansion of a surface cavity that has initial gas/vapor content. To apply to a paper wrapped conductor, we can assume the existence of tiny cavities on the paper surface initially filled with small amounts of water vapor and dissolved gases (mostly nitrogen). Under overload conditions the conductor and paper would overheat and the cavity would

[7] The numbers in brackets combined with the letter "A" correspond to those of the bibliography in Annex A.

expand at first into which water vapor would be injected. As the cavity grows, the bubble would have higher and higher quantities of water vapor. The nitrogen content would hardly change in such limited time. It becomes obvious that we should expect bubble formation to be dictated by water vapor release and not by the nitrogen content of the oil. The contribution from generated gases becomes even less important.

A.2 Experimental verification

Two coil models were used for experimental studies. One model had a fiber optic temperature sensor in place of thermocouple sensor to sense hot spot temperature and a separate winding was used to apply voltage for PD detection of bubbles in addition to visual observation. Moisture content of the paper in the coil and gas content of the oil were changed over a wide range. Moisture ranged from 0.5% to 8.0% (dry/oil free basis), and gas content, from fully degassed to (nitrogen) saturated. A rapid temperature rise simulated the conditions in a transformer winding under overload conditions.

It was observed that at low moisture values the bubble evolution temperature is virtually the same for degassed and gas saturated systems. The previous model had predicted a 50 °C difference. Only at high moisture levels there would be a significant influence from the gas content. It will also be noticed that at 2% moisture in paper (corresponding to an aged transformer) the bubble evolution temperature is slightly above 140 °C. At 0.5% moisture level the bubble evolution temperature is above 200 °C. In other words, even at the proposed 180 °C hot spot condition bubbles will not be produced from very dry insulation. However, most transformers have insulation moisture levels in the range of 1–1.5%; hence it is prudent not to exceed 150 °C hot spot temperature. Premature aging of paper and the resulting loss of life is always a concern, and the Loading Guide enables its users to estimate the loss of life from short-term overloads.

In addition to fully de-gas and fully gas saturated systems, several tests were conducted with partly degassed oil. In total, 22 coil model tests were conducted. It was possible to fit the hot spot temperature as a function of moisture and gas content and the total external pressure (atmospheric plus oil head). The equation is given below:

$$\Theta_{bubble} = \left[\frac{6996.7}{22.454 + 1.4495 \ln W_{WP} - \ln P_{pres}} \right] - \left[\left(e^{(0.473 W_{WP})} \right) \left(\frac{V_g^{1.585}}{30} \right) \right] - 273 \qquad \text{(A.2)}$$

Where

P_{pres} = Total pressure, mm mercury (torr.)

V_g = Gas content of oil, % (v/v)

W_{WP} = Per cent by weight of moisture in paper (dry basis)

Θ_{bubble} = Temperature for bubble evolution, °C

The first part of the equation between the braces is for degassed oil and was derived from the well known Piper chart of vapor pressure vs. moisture relationship. The second term adjusts for the gas content of the oil. The agreement between observed and computed temperatures was excellent, with not more than two degrees difference for tests with the single coil model, and not more than four degrees with the triple disc coil model (for which visual bubble observation was harder, and no PD detection was used).

There is no need to consider the contribution of generated gases as in the previous model because their level is far below that of the dissolved nitrogen.

Dry basis for the percent by weight of moisture in paper means that the moisture is based on the dry, oil- free weight of paper. The percentage water estimated on a 'wet, oily' basis (as is usually done) will be lower than on the dry, oil-free basis because the weight of the paper would include both oil and water.

A.3 Determination of equation parameters

There are two indirect methods for the assessment of moisture in paper insulation in transformers as follows:

1) Recovery Voltage Measurement (see Bognar et al. [A2]). This requires the application of a DC voltage while the transformer is de energized. Moisture estimates are made by comparison to systems with known moisture content.

2) Moisture Equilibrium Curves (see Degnan et al. [A5] and Du et al. [A27]). Under steady state conditions achieved at constant load, the moisture in paper and oil achieve equilibrium conditions. A set of equilibrium curves may be used for the estimation of moisture content of paper based on the moisture content of oil, which is easily determined.

Confirmation of moisture in paper can be obtained by measuring moisture in oil at two constant oil temperatures. It can be seen that the accuracy of estimation increases as higher and higher temperatures are chosen due to the slope of the curves, and also because equilibrium is achieved sooner. In practice, the oil temperature could be in the 50–80 °C range. Since the moisture in oil is measured in the lab from an oil sample taken, it is necessary to note the oil temperature. It is also necessary to keep the oil warm so that free water is not formed on cooling down (at room temperature moisture saturation is about 60 mg/kg (ppm), and hence a sample with 95 mg/kg (ppm) would produce some free water. By taking an oil sample at lower temperature the risk of saturation is avoided, but the accuracy of estimation would suffer. It is advised that some practice runs are made by the utility person. The effort is well worth it because once the moisture in the paper is determined, it is going to remain stable for a considerably long time. After a few years, the measurement may be repeated because aging of paper would slightly increase moisture content of paper. Any leaks or exposure of the insulation to the atmosphere would also affect the moisture content of the paper. After maintenance operations or field dry out, a repeat moisture determination should be made.

The oil head may be estimated from the outline drawing and the liquid level dimension given on the nameplate. Since the bubble evolution temperature during overload is of primary interest, the pressure may be assumed to be the maximum operating pressure given on the nameplate.

A.4 Example

Gas content may be estimated based on the type of liquid preservation system; however gas content only slightly affects the bubble evolution temperature calculated using Equation (A.2).

The following example illustrates the use of Equation (A.2):

Assume 1.2% water in the paper insulation. To compute the bubble evolution temperature from a winding at a depth of 2.4384 m from the top oil level of a large power transformer, the oil head must be added to the pressure in the gas space above the oil. Assume 1% gas content in the oil. Then,

Water in paper, W_{WP}	=	1.2 %
External pressure,	=	750 torr
Oil head (2.4384 m)	=	176 torr
Total pressure, P_{pres}	=	926 torr
Gas content, V_g	=	1.0 %

Using Equation (A.2), you get $\Theta_{bubble} = 167$ °C. With a gas content of 8%, the bubble evolution temperature would drop by only a degree. However, if the moisture content is also 8%, the bubble evolution temperature would be 63 °C. If the water content in the paper is 2%, the bubble evolution temperature would be in the 140–150 °C range. Some published papers on bubble evolution have stated that 140 °C is the bubble evolution temperature, but the moisture content was not specified or accurately determined (Heinrichs [A16]). The new equation is applicable to aged and somewhat wet insulation.

Moisture content appears to be the most critical parameter in determining bubble evolution temperature. However, direct moisture determination would require a paper sample, especially from the hot spot region. This is not practical; hence indirect methods have to be used. The moisture parameter used in Equation (A.2) is the average moisture content.

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Annex B

(normative)

Effect of loading transformers above nameplate rating on bushings, tap changers, and auxiliary components

B.1 Bushings

B.1.1 General

The following discussion applies to oil-impregnated, paper-insulated, capacitance-graded bushings only. For other bushing types, consult with the manufacturer for loading guidelines. Bushings are normally designed with a hottest- spot total temperature limit of 105 °C at rated bushing current with a transformer top-oil temperature of 95 °C averaged over a 24 h time period. Operating a transformer beyond nameplate current can result in bushing temperatures above this limit, which cause bushing loss-of-life depending on the actual time-temperature profile the bushing sees.

A number of factors that reduce the severity of bushing overloads compared to transformer winding insulation overloads include the following:

a) Transformer top-oil temperature may be well below 95 °C at rated transformer output. b) Bushings are sealed units preserving insulation and thermal integrity.
c) Bushing insulation is usually drier than transformer insulation.

d) Bushing insulation is not significantly stressed by fault-current forces.

e) The use of bushings with higher current ratings than the connected transformer windings.

Possible bushing overload effects include the following:

– Internal pressure build-ups

– Aging of gasket materials

– Unusual increases in power factor from thermal deterioration

– Gassing caused by hottest-spots in excess of 140 °C

– Thermal runaway from increased dielectric losses at high temperatures

– Heating in metallic flanges due to stray magnetic flux

The following overload limits are established for coordination of bushings with transformers:

Ambient air	40 °C maximum
Transformer top-oil temperature	110 °C maximum
Maximum current	2 times rated bushing current
Bushing insulation hottest-spot temperature	150 °C maximum

Methods for calculating bushing lead steady-state and transient hottest-spot temperatures are included in IEEE Std C57.19.100™ [B3].[8]

The insulation used in condenser bushings is not thermally upgraded. The relation of insulation deterioration to changes in time and temperature is assumed to follow an adaptation of the Arrhenius reaction rate theory, which states that the logarithm of insulation life is a function of the reciprocal of absolute temperature.

$$Log_{10}(LIFE) = \left[\frac{6972.15}{\Theta_{HS} + 273} - 14.133\right] \tag{B.1}$$

where

LIFE is the life of bushing insulation, h

Θ_{HS} is the bushing insulation hottest-spot temperature, °C

Equation (B.1) indicates that bushings operated at rated current and rated insulation hot-spot temperature have a predicted life less than that of the transformer insulation. In most cases, bushings are applied at less than rated top-oil temperature and in many cases the transformer rated current is less than the bushing rated current. This results in bushing life equivalent to the transformer insulation life. Considerations may also be given to using a per-unit life concept and the insulation aging Equation (3) for 55 °C rise transformers.

B.1.2 Draw leads in bushings

Some bushings are designed for a solid or hollow copper rod inside the bushing to give the full bushing rating. Some bushings are also designed to substitute a draw lead cable for the conductor inside the bushings. When a bushing is operated in the draw lead mode, the thermal performance is determined by the size of the lead supplied as part of the transformer, and the nameplate rating of the bushing may not apply. The draw leads may limit transformer loading to less than the capability of the transformer winding insulation or the capability of the bushing.

B.2 Tap-changers

B.2.1 Tap-changers for de-energized operation (TCDO)

ANSI standards do not specify the temperature rise of the contacts for TCDOs. However, TCDO and LTC tap-changers have similar requirements concerning temperature rise of contacts. The rise will also depend on the design of contacts and the "condition" of the contacts when the loading occurs. Although tap-changer contacts may have certain overload capabilities when new, these capabilities may decrease due to a thin film build-up on the contacts that occurs during normal service. Once a contact reaches a critical temperature, a thermal runaway condition can occur. The contacts overheat and a deposit builds up around the contacts, increasing contact resistance until it finally reaches a temperature that will generate gas. As a minimum, this will produce a gas alarm. As a maximum, the gas may trigger a dielectric failure of the transformer.

The thin film build-up described above can be effectively controlled if the TCDO is operated a minimum of once a year. This can be done during an outage for maintenance or whenever the transformer is de-energized to change taps. Whenever this opportunity occurs, the TCDO should be operated across its full range approximately 10 times to ensure that all the contacts have been wiped clean. With clean contacts, the problem of thermal runaway and deposit buildup during overload conditions can be minimized. After operation of the TCDO it would be good industry practice to perform electrical tests of the transformer to confirm correct operation and final position of the TCDO prior to re-energization.

[8] The numbers in brackets combined with the letter "B" correspond to those of the bibliography in Annex B.

If, in the transformer owner's experience, the de-energized tap-changer has been operated periodically without problems, the previous paragraph is recommended to ensure that the contacts will remain in the best possible condition. However, if, in the owner's experience, the de-energized tap changer has not proven to be completely reliable (as a result of misalignment of the contacts or failure of the mechanized mechanism), the owner may not wish to operate it under any circumstances.

The decision to follow the recommendation of the above paragraph should be tempered by the actual experience with each transformer.

B.2.2 Load tap-changers

IEEE Std C57.131™ [B4] and ~~[BB1~~IEC 60214 [B1] provide the basis for the rating of a load tap-changer. Most North American transformer manufacturers have complied with the requirements of IEC 60214 [B1] prior to the approval of IEEE Std C57.131 [B4]. The manufacturer should be consulted if it is necessary to assure that a specific LTC has been designed to these standards.

According to both standards, the basis for the current rating of an LTC includes the following:

a) Temperature rise limit of 20 °C for any current carrying contact in oil when operating at 1.2 times the maximum rated current of the LTC.

b) Capable of 40 breaking operations at twice maximum rated current and kVA. Oscillograms taken for each operation shall indicate that in no case is the arcing time such as to endanger the operation of the apparatus.

Standards allow tap-changer contacts to work in 100 °C oil with a temperature rise of 20 °C at 1.2 times the nameplate rating. Also, experience has shown that carbon starts to develop on contacts in oil at elevated temperatures (in the order of 120 °C). How serious this growth of carbon becomes depends on the wiping action of the switch contacts, the frequency that switch operation takes place, and how long the high temperature persists. Another important factor is whether the LTC is located in the main tank or in a separate compartment. Usually arcing contacts of the LTC are located in a separate compartment and the oil temperature is less than 100 °C.

Contact temperature rise over oil can be estimated using the following equation:

$$\Delta\Theta_c = \Delta\Theta_{c,R} \times K^n \tag{B.2}$$

where

$\Delta\Theta_c$ is the contact temperature rise over oil at per-unit load K, °C
$\Delta\Theta_{c,R}$ is the contact temperature rise over oil at rated current, °C
K is the load through the LTC in per unit of LTC current rating
n is the exponent of contact temperature rise and may vary over a range of 1.6–1.85. If an exact exponent, based on test results, is not known, a value of 1.8 may be used.

Total contact temperature can then be determined as follows:

$$\Theta_c = \Theta_A + \Delta\Theta_{TO,LTC} + \Delta\Theta_c \tag{B.3}$$

where

Θ_c is the total contact temperature, °C
ΘA is the ambient temperature, °C
$\Delta\Theta_{TO,\ LTC}$ is the oil temperature rise over ambient in LTC compartment at per-unit load K, °C
$\Delta\Theta_c$ is the contact temperature rise over oil, °C

The top-oil temperature in the LTC compartment may not be readily available unless the LTC is located in the main tank of the transformer. If the LTC is located in a separate tank, the LTC oil may be in the order of 5–15 °C cooler than the top-oil temperature in the main tank at rated load. As a rule of thumb, it can usually be assumed that the temperature rise of the oil in a separate tank is 80% of the oil temperature rise in the main tank.

The following is an example using the previous equations for the case where the LTC is located in a separate compartment. This calculation shows that the LTC could carry an emergency load of as high as 1.32 pu at an ambient of 30 °C before a contact temperature of 120 °C is reached. This assumes that, per the standards, the temperature rise of the contacts is 20 °C at 1.2 times the maximum rated load and that the oil temperature rise in the separate compartment is 66 °C at 1.32 pu load.

$$\Delta\Theta_{c,R} = \frac{\Delta\Theta_c}{K^n} = \frac{20}{(1.2)^{1.8}} = 14.4\ ^\circ C$$

where

K is the ratio of load L to rated load, per unit

N is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.

$\Delta\Theta_c$ is the contact temperature rise over oil, °C

$\Delta\Theta_{c,R}$ is the contact temperature rise over oil at rated load, °C

Θ_A is ambient, °C = 30 °C

$\Delta\Theta_{TO,\,LTC}$ is the oil rise in LTC compartment (80% of top-oil rise of 82 °C at 1.32 pu load), °C = 66 °C

$\Delta\Theta_c$ is the maximum contact temperature rise = 14.4 × $(1.32)^{1.8}$, °C = 24 °C

Total 120 °C

Some LTC manufacturers have advised caution about using the above approach. One caution is that the cooling ability of the contact geometry and contact mass are also important to consider. In addition, it is not physically possible to actually measure the temperature at the contact point. What is actually measured is a point close to the contact point. The temperature of the actual contact point will be considerably higher. A well-designed transformer will have an LTC capable of carrying the same load as the core and coils. That is, the hottest-spot temperature in the transformer will be the limitation to loading, not the LTC contact temperature. If this is the case, calculations as shown above would not be necessary. However, such calculations may be useful if the LTC limits the output of the transformer.

LTCs designed in accordance with IEEE Std C57.131 [B4] and IEC standards must be capable of 40 breaking operations at twice maximum rated current and kVA. The user would be wise, however, to exercise caution before operating an LTC in this fashion. It should be realized that a factory test is made under ideal conditions (new oil, new contacts, recently adjusted, etc.). Most LTC manufacturers would agree to a few operations per year at twice rated current and kVA. As the number of operations at twice rated current increases, not only would there be additional contact deterioration, but the likelihood of failure of the LTC would also increase. The wear of contacts and contamination of oil increases rapidly with current. Higher overloads on an LTC will necessitate more frequent maintenance.

B.3 Bushing-type current transformers

B.3.1 General

In their normal location, bushing-type current transformers have the transformer top-oil as their ambient, which is limited to 105 °C total temperature at rated output for 65 °C rise transformers. Loading the power transformer beyond nameplate results in an increase in top-oil temperature and secondary current in the current transformer with an associated temperature rise.

A factor in reducing the severity of the current transformer overload is that the top-oil temperature at rated transformer output may be well below 105 °C. In cases where consideration of the loading and top-oil temperature rise of the power transformer and the current in the current transformer indicates the possibility of excessive operating temperatures in the current transformer, the manufacturer should be consulted on the current transformer capability before loading beyond its nameplate rating. The capability of bushing current transformers under operating conditions cannot necessarily be derived from the rating factor.

It may also be possible to select higher current transformer ratios to reduce secondary currents and thus increase the capability of the current transformer.

B.4 Insulated lead conductors

Within the transformer, connections to tap-changer and line terminals and other internal connections are made with insulated leads and cables. The method of calculating the hottest-spot temperature for these leads is different from that employed for the windings. However, the same hottest-spot limits apply equally for both windings and leads since similar insulating materials are normally used. Generally, the loading of the transformer will not be limited by the lead temperature rise. Recommendations of the manufacturer should be sought if proposed loading cycles are in excess of original specifications for the transformer.

B.5 Bibliography for Annex B

[B1] IEC 60214, On-load tap-changers.
[B2] IEEE Std C57.13~~-1993,~~™, IEEE Standard Requirements for Instrument Transformers.
[B3] IEEE Std C57. 19.100~~-1995~~, IEEE Guide for Application of Power Apparatus Bushings.
[B4] IEEE Std C57. 131~~-1995~~, IEEE Standard Requirements for Load Tap Changers~~ (ANSI).~~.

Annex C

(informative)

Calculation methods for determining ratings and selecting transformer size

C.1 General

A transformer application problem usually needs to answer the question, "Is an available transformer suitable for a given load cycle?" Calculations required to answer this question can be made by hand, or a computer program can be written to automate the calculation. This annex will illustrate calculation procedures used for the determination of loading limits and the selection of a transformer rating. It should be noted that the purpose of the illustration is to show one way to approach the problem. As in most engineering problems, different approaches are possible and judgment must be used in interpreting the results. The principles outlined in the following examples can be applied to all sizes and ratings of transformers. The calculation methods of Annex I may be used to determine if the loss of insulation life for these examples is acceptable.

C.2 Calculation determining loading beyond nameplate rating of an existing transformer

For this example, a 65 °C rise triple rated, ONAN/ODAF/ODAF directed forced-oil cooled transformer rated 112 000/149 333/186 666 kVA will be used. A load profile is given (see Table C.1, normal load in per unit) for a day starting at 6:00 a.m. The hottest-spot winding temperature profile will be determined by calculation. Some simplifying assumptions will be made to make the calculation easier. The first assumption is that maximum cooling will be used throughout the day, even though at the lowest part of the load cycle, the loading will be less than the intermediate rating. The assumption may be optimistic; on the other hand, when loading beyond nameplate rating is planned, it is reasonable to assume that every measure is taken to assist the transformer, including the use of maximum cooling throughout the day.

For the directed forced oil cooling, the *n* exponent is 1 and no correction of the time constant is required. That is,

$$\tau_{TO} = \tau_{TO,R}$$

where

τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h

$\tau_{TO,R}$ is the time constant for rated load beginning with initial top-oil temperature rise of 0 °C, h

For cooling modes with $n < 1$ the time constant should be corrected and this refinement is easily accomplished with a computer program.

The third assumption is that the load is kept constant during the following hour. For the rising part of the load curve this assumption will give loads that are too low, but on the falling part of the load curve loading values that will be too high. It is possible to refine the load representation when there is need.

The last assumption is that the ambient temperature is constant during the day.

Table C.1— Load cycles and temperature rises for 187 MVA transformer

Normal load						PLBN				LTE				STE			
Hour	Load pu	A© TO	A© TO	A©ff	®H	Load pu	A© TO	A©ff	®H	Load pu	A© TO	A©ff	®H	Load pu	A© TO	A©ff	®H
6	0.52	18.14	19.20	7.73	56.9	0.66	26.86	12.46	69.3	0.66	26.86	12.46	69.3	0.66	26.86	12.46	69.3
7	0.55	17.14	17.94	8.65	56.6	0.69	24.91	13.62	68.5	0.69	24.91	13.62	68.5	0.69	24.91	13.62	68.5
8	0.61	16.63	17.23	10.63	57.9	0.77	23.75	16.96	70.7	0.77	23.75	16.96	70.7	0.77	23.75	16.96	70.7
9	0.70	16.76	17.21	14.01	61.2	0.88	23.74	22.15	75.9	0.88	23.74	22.15	75.9	0.88	23.74	22.15	75.9
10	0.79	17.74	18.07	17.85	65.9	1.00	25.08	28.60	83.7	1.00	25.08	28.60	83.7	1.00	25.08	28.60	83.7
11	0.85	19.47	19.71	20.66	70.4	1.07	27.76	32.74	90.5	1.07	17.76	32.74	90.5	1.07	27.76	32.74	90.5
12	0.90	21.49	21.67	23.17	74.8	1.13	30.85	36.52	97.4	1.13	30.85	36.52	97.4	1.13	30.85	36.52	97.4
13	0.93	23.66	23.79	24.74	78.5	1.17	34.14	39.15	103.3	1.29	34.14	39.15	103.3	1.92	34.14	39.15	103.3
												47.59	111.7		a	a	a
14	0.96	25.69	25.79	26.36	82.2	1.21	37.29	41.87	109.2	1.33	39.48	50.59	120.1	1.33	46.76	50.59	127.4
15	0.98	27.64	27.71	27.47	85.2	1.23	40.36	43.27	113.6	1.36	44.27	52.90	127.2	1.36	49.73	52.90	132.6
16	0.99	29.39	29.44	28.03	87.5	1.25	43.03	44.69	117.7	1.38	48.46	54.47	132.9	1.38	52.55	54.47	137.0
17	1.00	30.84	30.88	28.60	89.5	1.26	45.40	45.41	120.8	1.39	52.01	55.26	137.3	1.39	55.07	55.26	140.3
18	1.00	32.08	32.11	28.60	90.7	1.26	47.36	45.41	122.8	1.39	54.87	55.26	140.1	1.39	57.17	55.26	142.4
19	0.98	33.01	33.03	27.47	90.5	1.23	48.83	43.27	122.1	1.23	57.02	55.26	142.3	1.23	58.74	55.26	144.0
												43.27	130.3			43.27	132.0
20	0.97	33.41	33.43	26.91	90.3	1.22	49.38	42.57	122.0	1.22	55.52	42.57	128.1	1.22	56.81	42.57	129.4
21	0.94	33.57	33.58	25.27	88.9	1.18	49.61	39.82	119.4	1.18	54.21	39.82	134.0	1.18	55.18	39.82	125.0
22	0.90	33.26	33.27	23.17	86.4	1.13	49.07	36.52	115.6	1.13	52.52	36.52	119.0	1.13	53.25	36.52	119.8
23	0.86	32.49	32.49	21.15	83.6	1.08	47.81	33.36	111.2	1.08	50.39	33.36	113.8	1.08	50.94	33.36	114.3
24	0.81	31.39	31.39	18.76	80.2	1.02	46.04	29.76	105.8	1.02	47.98	29.76	107.7	1.02	48.39	29.76	108.2
1	0.68	29.94	29.94	13.22	73.2	0.86	43.78	21.15	94.9	0.86	45.23	21.15	96.4	0.86	45.54	21.15	96.7
2	0.61	27.42	27.42	10.64	68.1	0.77	39.85	16.96	86.8	0.77	40.94	16.96	87.9	0.77	41.17	16.96	88.1
3	0.58	24.86	24.86	9.62	64.5	0.73	35.82	15.24	81.1	0.73	36.63	15.24	81.9	0.73	36.81	15.24	82.1
4	0.55	22.67	22.67	8.65	61.3	0.69	32.35	13.62	76.0	0.69	32.96	13.62	76.6	0.69	33.09	13.62	76.7
5	0.53	20.78	20.78	8.03	58.8	0.67	29.33	12.84	72.2	0.67	29.78	12.84	72.6	0.67	29.88	12.84	72.7
6	0.52	19.20	19.20	7.73	56.9	0.66	26.86	12.46	69.3	0.66	27.20	12.46	69.7	0.66	27.27	12.46	69.7

See C.5 for temperature rises at 13:30 h.

The transformer characteristics at 187 MVA are as follows:

Top-oil rise over ambient at rated load $\Delta\Theta_{TO,R}$ = 36.0 °C Hottest-spot conductor rise over top-oil temperature, at rated load $\Delta\Theta_{HS,R}$ = 28.6 °C Ratio of load loss at rated load to no-load loss R = 4.87

Oil thermal time constant for rated load $\tau_{TO,R}$ = 3.5 h

Exponent of loss function vs. top-oil rise $n = 1.0$

Exponent of load squared vs. winding gradient $m = 1$

The ultimate top-oil rise over ambient for load K will be, according to Equation (11).

$$\Delta\Theta_{TO,U} = \Delta\Theta_{TO,R}\left[\frac{K_U^2 R + 1}{(R+1)}\right]^n \qquad (C.1)$$

$$\Delta\Theta_{TO,U} = 36\left[\frac{K_U^2(4.87)+1}{(4.87+1)}\right]^n$$

$$\Delta\Theta_{TO,U} = 29.87K_U^2 + 6.13$$

where

K_U is the ratio of the ultimate load L to rated load, per unit

R is the ratio of load loss at rated load to no-load loss on the tap position to be studied

$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C

$\Delta\Theta_{TO,R}$ is the top-oil rise over ambient temperature at rated load on the tap position to be studied, °C

After 1 h the top-oil temperature rise will be [see Equation (9)].

$$\Delta\Theta_{TO} = (\Delta\Theta_{TO,U} - \Delta\Theta_{TO,i})\left(1 - e^{-\frac{t}{\tau_{TO}}}\right) + \Delta\Theta_{TO,i}$$

where

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C

$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C

$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for t = 0, °C

τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h t is the duration of load, h or rewritten:

$$\Delta\Theta_{TO} = \Delta\Theta_{TO,U}\left(1 - e^{-\frac{t}{\tau_{TO}}}\right) + \Delta\Theta_{TO,i}\, e^{-\frac{t}{\tau_{TO}}}$$

where

t is the duration of load, h

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C

$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C

$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for t = 0, °C

τ is the oil time constant of transformer, h

τ_{TO} is the oil time constant of transformer for any load L and for any specific temperature differential between the ultimate top-oil rise and the initial top-oil rise, h

When we substitute $\tau_{TO} = \tau_{TOR} = 3.5$, and the $\Delta\Theta_{TO,U}$ value of Equation (C.1), we obtain for t = 1 h.

$$\Delta\Theta_{TO} = (29.87K^2 + 6.13)\left(1 - e^{\frac{-1}{3.5}}\right) + \Delta\Theta_{TO,i}\, e^{\frac{-1}{3.5}}$$

where

K is the ratio of load L to rated load, per unit

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C

$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for t = 0, °C or or

and for t = 0.5 h

$$\Delta\Theta_{TO} = 7.42K^2 + 1.53 + 0.75\Delta\Theta_{TO,i} \tag{C.2}$$

$$\Delta\Theta_{TO} = 3.98K^2 + 0.82 + 0.87\Delta\Theta_{TO,i} \tag{C.3}$$

The winding hot-spot rise over top oil will be according to Equation (18).

$$\Delta\Theta_{TO} = \Delta\Theta_{H,R}K^{2m} = 28.6K^2 \tag{C.4}$$

where

K is the ratio of load L to rated load, per unit

m is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See Table 4.

$\Delta\Theta_{H,R}$ is the winding hottest-spot rise over top-oil temperature at rated load on the tap position to be studied, °C

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C

One quantity, the initial top-oil rise, is still missing and we will have to estimate it. If we assume the load cycle for normal load found in Table C.1, we may establish the rms value of the load curve, as an example, for the 6 h load preceding 6:00 a.m.

$$K = \sqrt{\frac{\left[(0.81)^2 + (0.68)^2 + (0.61)^2 + (0.58)^2 + (0.55)^2 + (0.53)^2\right]}{6}} = 0.634$$

Using Equation (C.1), a load of this magnitude yields an ultimate top-oil rise of

$$\Delta\Theta_{TO,U} = 29.87K^2 + 6.13 = 29.87(0.634)^2 + 6.13 = 18.14^\circ C$$

Using $\Delta\Theta_{TO,i}$ = 18.14 °C at 6:00 a.m., and K = 0.52, we can determine $\Delta\Theta_{TO}$ at 7:00 a.m. as follows:

$$\Delta\Theta_{TO,U} = 7.42K^2 + 1.53 + 0.75\Delta\Theta_{TO,i} = 17.14^\circ C$$

where

K is the ratio of load L to rated load, per unit

$\Delta\Theta_{TO,U}$ is the ultimate top-oil rise over ambient temperature for load L, °C

$\Delta\Theta_{TO,i}$ is the initial top-oil rise over ambient temperature for t = 0, °C

To determine the top-oil temperature rise at 8:00 a.m., set $\Delta\Theta_{TO,i}$ = $\Delta\Theta_{TO}$ calculated at 7:00 a.m. Repeated application of Equation (C.2) will produce a top-oil temperature rise profile; however, a slight discrepancy occurs 24 h later at 6:00 a.m. When one continues to apply Equation (C.2), convergency to true values is soon obtained, as shown in normal load, $\Delta\Theta_{TO}$ columns of Table C.1. The first column represents the first iteration, and the second column represents the results after an additional iteration.

The winding hot-spot rise over top oil, $\Delta\Theta_{TO}$ is considered to be instantaneous. Only where current discontinuities occur will some consideration be given to the winding time-constant.

For example, at 6:00 a.m.:

$$\Delta\Theta_H = (28.6)(0.52)^2 = 7.73^\circ C$$

The equation, $\Theta_H = \Delta\Theta_{TO} + \Delta\Theta_H + \Theta_A$, will be used to establish the hottest-spot winding temperature Θ_H, using for ambient temperature Θ_A = 30.0 °C.

A complete daily normal load cycle is shown in Table C.1 and plotted in Figure C.1.

C.3 Planned loading beyond nameplate (PLBN)

The constant on PLBN loading is hottest-spot winding temperatures in the 120–130 °C range; therefore, $\Delta\Theta_{TO} + \Delta\Theta_H$ = 120 °C – Θ_A = 90 °C. The three highest temperatures for the normal loading cycle are just over 90.3 °C; therefore, $\Delta\Theta_{TO} + \Delta\Theta_H$ = 60.3 °C.

To estimate what load multiplier K should be to produce $\Delta\Theta_{TO} + \Delta\Theta_H$ = 90 °C, we proceed as follows:

$$\left[\frac{\left(K^2R+1\right)}{(R+1)}\right]^n = \frac{90}{60.3}$$

where

K is the ratio of load L to rated load, per unit

N is an empirically derived exponent used to calculate the variation of $\Delta\Theta_{TO}$ with changes in load. The value of n has been selected for each mode of cooling to approximately account for effects of change in resistance with change in load. See Table 4.

R is the ratio of load loss at rated load to no-load loss on the tap position to be studied

and solving for K gives

K = 1.26

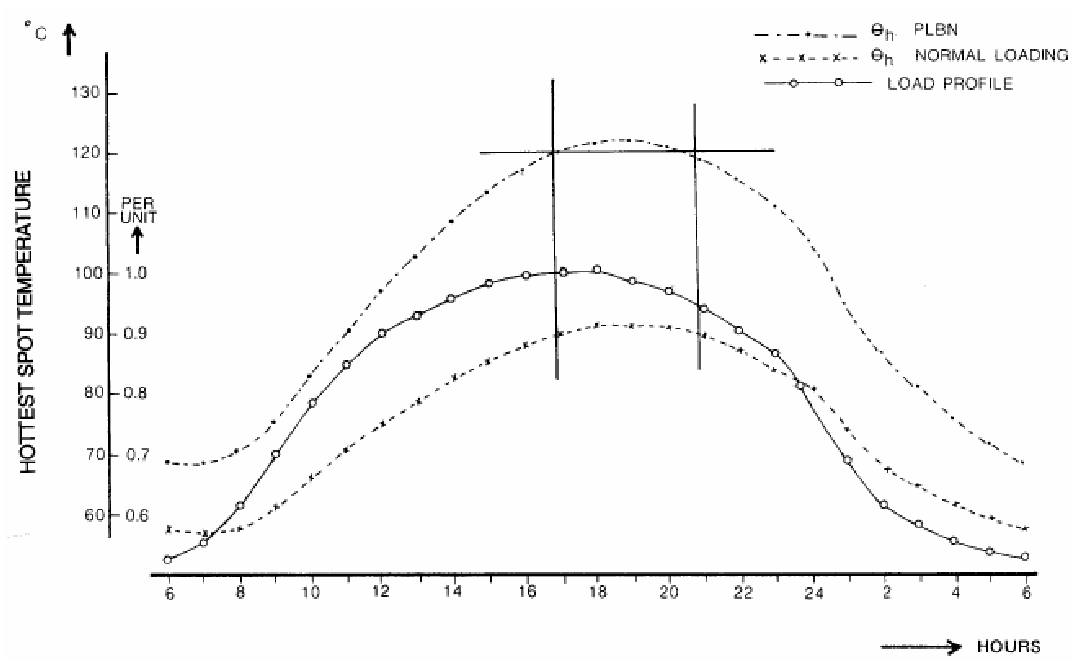

Figure C.1— Load cycles for normal loading and planned loading beyond nameplate

The top-oil rise is not quite proportional to the square of the load current (no-load losses are constant) but the winding gradient is proportional to the square of the load current. The multiplier may have to be corrected if it is unsatisfactory. Again we have to estimate an initial top-oil temperature. Following the same procedures as for the normal load, we obtain a temperature profile, based on the load cycle shown in Figure C.1. The hottest-spot temperature is in the 120–130 °C range for close to 4 h.

C.4 Long-time emergency loading (LTE)

A user has to consider carefully the emergency loading conditions that may occur on his system. A maximum period of 6 h is used in our example. Assume that the long time emergency begins at 13:00 h, and was preceded by a PLBN loading. Suppose a load multiplier of value K_2 is applied.

At 13:00 h:

$\Delta\Theta_{TO,i}$ = 33.90 °C, which is equal to $\Delta\Theta_{TO}$ in the PLBN loading. Apply Equation (C.2) to find this value.

At 14:00 h:

$$\Delta\Theta_{TO} = \left(7.42 \times 0.93 K_2^2\right) + 1.53 + \left(0.75 + 34.14\right) = 6.42 K_2^2 + 27.14$$

$$\Delta\Theta_H = \left(28.6 \times 0.96 K_2^2\right) = 26.36 K_2^2$$

At 15:00 h:

$$\Delta\Theta_{TO} = \left(7.42 \times 0.96 K_2^2\right) + 1.53 + \left(0.75\right)\left(6.42 K_2^2 + 27.14\right) = 11.66 K_2^2 + 21.89$$

$$\Delta\Theta_H = 27.47 K_2^2$$

Repeated application of Equation (C.2) finally gives at 19:00 h an equation for $\Delta\Theta_{TO}$ and $\Delta\Theta_H$ in terms of K_2 as follows:

$$\Delta\Theta_{TO} = \Delta\Theta_H = 51.25 K_2^2 + 11.11$$

The LTE constraint is 140 °C, thus,

$$51.25 K_2^2 + 11.11 + 30 = 140.0$$

and

$K_2 = 1.39$

Table C.1 shows the top-oil rise and the winding gradient. At 13:00 h and at 19:00 h, there is a discontinuity in current. The winding time-constant usually is in the order of 3–5 min. After 20 min, ΔT_{HS} will be according to the new load. Figure C.2 shows the hottest-spot temperature profile. The 140 °C temperature limitation has been met. The hottest-spot temperature is in the 130–140 °C range less than 6 h and in the 120–130 °C range longer than 4 h, so a value of 1.39 applied to the per-unit load from 13:00–19:00 hours seems to be in order.

C.5 Short-time emergency (STE) loading

In our example, an STE loading is assumed to occur at 13:00 h, following a PLBN loading. After 1/2 h, the load is reduced to the LTE loading, which will persist for 5.5 h. We will use an interval load value K_3. The STE constraint is a maximum hottest-spot temperature of 180 °C.

At 13:00 h:

$$\Delta\Theta_{TO,i} = 34.14^{\circ}C$$

Apply Equation (C.3) (for t = 0.5 h) to obtain at 13:30 h

$$\Delta\Theta_{TO} = 3.98K^2 + 0.82 + 0.87(34.14)$$

$$\Delta\Theta_H = 28.6K_3^2$$

$$\Theta_H = \Delta\Theta_{TO} + \Delta\Theta_H + \Theta_A = 32.58K_3^2 + 30.52 + 30.0 + 180.0$$

where

K_3 is the ratio of load L to rated load, per unit

Θ_A is the average ambient temperature during the load cycle to be studied, °C

Θ_H is the winding hottest-spot temperature, °C

$\Delta\Theta_H$ is the winding hottest-spot rise over top-oil temperature, °C

$\Delta\Theta_{TO}$ is the top-oil rise over ambient temperature, °C

K_3= 1.92

At 13:30 h: $\Delta\Theta_{TO}$ = 45.19 °C, $\Delta\Theta_H$ = 105.43 °C, Θ_H = 180.6 °C, load = 1.29 per unit

At 14:00 h: $\Delta\Theta_{TO}$ = (3.98) $(1.29)^2$ + 0.82 + (0.870) (45.19) =46.76 °C

Figure C.2 shows the temperature excursion to be within the limits for the STE loading. The hottest-spot temperature will be somewhat longer in the 130–140 °C range limit.

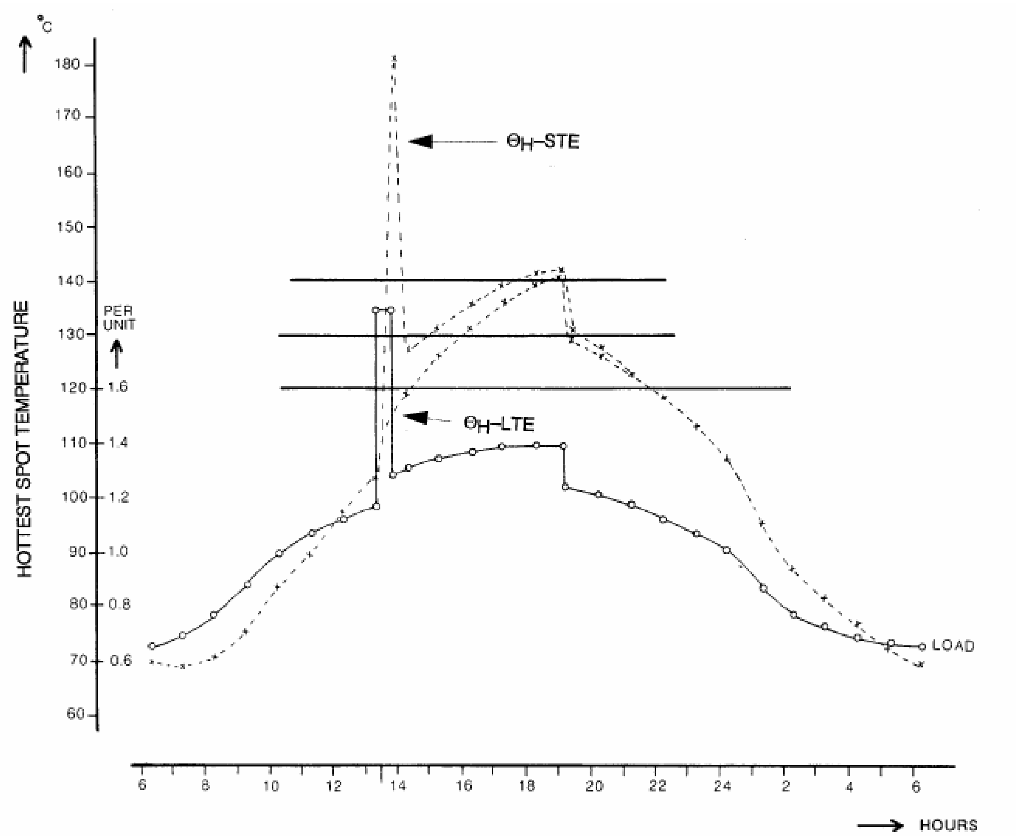

Figure C.2—Hottest-spot temperature profile for long time and short time emergency loading

Annex D

(normative)

Philosophy of guide applicable to transformers with 55 °C average winding rise

(65 °C hottest-spot rise) insulation systems

D.1 General

Loading of transformers above nameplate is a controversial subject. Agreement on the loading limits can be agreed upon with the manufacturer if they have been clearly specified prior to the design of the transformer. However, since there has been new knowledge gained in recent years concerning stray flux fields and their effects of metallic temperatures, it is desirable to confirm greater than nameplate load capabilities with the manufacturers of transformers on critical systems.

Some users have considerable experience in loading power transformers above nameplate using computer programs in conjunction with IEEE Std C57.92-1981 and NEMA TR98-1978. Since this approach deals with loss of life due to the effects of thermal aging of the windings, it should always be accompanied with due consideration given to the load capabilities of all other components in the transformer. These components include bushings, tap-changers and terminal boards, current transformers, and leads. Relay settings should also be checked so that load is not dumped. Consideration should also be given to oil expansion and its effect on possible mechanical relief device operation, subsequent possible operation of the fault-pressure relay, and oil clogging of breathing devices. Forced-oil cooler fouling should also be a consideration when determining load capability. This fouling is particularly found in areas having salt spray environments or dust and chemical contaminants present. These computer programs should be modified to reflect this new loading guide where its use may lead to more conservative loading. The loss of a single transformer of over 100 MVA rating rarely causes power interruption of customers. However, loss of one transformer due to its failure or due to the failure of some other part in the electrical circuit can result in increased loading of the back-up transformers. Most utilities do not design for second contingencies without loss of load. The adverse consequences are therefore rather great if the increased loading of the back-up transformer results in a failure.

Common sense and good planning are required to keep the economic gains in balance with the risks of failure. Because excessive transformer temperatures weaken the insulation structures physically, and because many of the older transformers have low impedances, short-circuit failures should also be considered. The types of transformer construction are a factor in making this assessment. Most utilities load these transformers conservatively. Gas evolution in power transformers is not a new insulation contaminant. There are at least eight causes of gas within the transformer that have been documented. The risk of having a failure due to free gas in the insulating structure should take into consideration the insulation margins used and the construction of the insulation structures. The risk of failure increases considerably when the insulation levels are reduced three full steps from a typically accepted level such as use of 650 kV BIL on 230 kV transformers. The risk decreases when no insulation collars are used in highly stressed parts of these transformers with reduced BIL. Knowledgeable transformer engineers have paid close attention to gas evolution when specifying and designing these transformers.

The loading of transformers without thermally upgraded insulation (from an insulation aging point of view) can be considered to be similar to transformers with thermally upgraded insulation. The calculation of temperatures included in Clause 7 and Annex G may be applied equally well for transformers without thermally upgraded insulation. Equation (3) in Clause 5 gives the equation to calculate equivalent aging and loss of life for transformers with 55 °C rise insulation systems. The normal loss of life ratings are loadings that result in a daily loss of life equal to that of a continuous winding hottest-spot temperature of 95 °C for 55 °C rise transformers.

The factor that determines the greatest risk associated with loading transformers above nameplate rating is the evolution of free gas from the insulation of winding and lead conductors. This gas will result from the following two major sources:

a) *Vaporization of water contained in the insulation.* This process is discussed in Annex A of this guide.

b) *Thermal decomposition of cellulose*. Data on the constituent gases and their proportions released by thermal decomposition of both thermally up-graded and non-upgraded cellulose insulation may be found in many of the references in the bibliographies for Annex A and Annex I.

D.2 Aging equations

For older transformers with 55 °C average winding rise insulation systems with a rated hottest-spot rise over ambient of 65 °C and a 30 °C ambient, the reference temperature is 95 °C. The equations for per-unit life and the aging acceleration factor are as follows:

$$\text{Per unit life} = 2.00 \times 10^{-10} e^{\left[\frac{15000}{\Theta_H + 273}\right]} \qquad \text{(D.1)}$$

where

Θ_H is the winding hottest-spot temperature, °C

$$F_{AA} = e^{\left[\frac{15000}{368} - \frac{15000}{\Theta_H + 273}\right]} \qquad \text{(D.2)}$$

where

F_{AA} is the aging acceleration factor

Θ_H is the winding hottest-spot temperature, °C

Annex E

(normative)

Unusual temperature and altitude conditions

E.1 Unusual temperatures and altitude

Transformers may be applied at higher ambient temperatures or at higher altitudes than specified in IEEE Std C57.12.00~~-1993~~, but performance may be affected, and special consideration should be given to these applications.

E.2 Effect of altitude on temperature rise

The effect of the decreased air density due to high altitude is to increase the temperature rise of transformers since they are dependent upon air for the dissipation of heat losses.

E.3 Operation at rated kVA

Transformers may be operated at rated kVA at altitudes greater than 1000 m (3300 ft) without exceeding temperature limits, provided the average temperature of the cooling air does not exceed the values of Table E.1 for the respective altitudes.

a) See 4.3.2 and Table 1 in IEEE Std C57.12.00-~~1993~~ 2010 for corrections of transformer insulation capability at altitudes above 1000 m (3300 ft).

b) Operation in low ambient temperature with the top liquid at a temperature lower than –20 °C may reduce dielectric strength between internal energized components below design levels.

E.4 Operation at less than rated kVA

Transformers may be operated at altitudes greater than 1000 m (3300 ft) without exceeding temperature limits, provided the load to be carried is reduced below rating by the percentages given in Table E.2 for each 100 m (330 ft) and that the altitude is above 1000 m (3300 ft).

Table E.1—Maximum allowable average temperature[a] of cooling air for carrying rated kVA

Method of cooling apparatus	1000 m (3300 ft)	2000 m (6600 ft)	3000 m (9900 ft)	4000 m (13200 ft)
Liquid-immersed self-cooled	30	28	25	23
Liquid-immersed forced-air-cooled	30	26	23	20
Liquid-immersed forced-oil-cooled with oil-to-air cooler	30	26	23	20

[a] It is recommended that the average temperature of the cooling air be calculated by averaging 24 consecutive hourly readings. When the outdoor air is the cooling medium, the average of the maximum and minimum daily temperatures may be used. The value obtained in this manner is usually slightly higher by not more than 0.3 °C than the true daily average.

Table E.2—Rated kVA correction factors for altitudes greater than 1000 m (3300 ft)

Types of cooling	Derating factor% per 100m (330 ft
Liquid-immersed air-cooled	0.4
Liquid-immersed water-cooled	0.0
Liquid-immersed forced-air-cooled	0.5
Liquid-immersed forced-liquid-cooled with liquid-to-air cooler	0.5
Liquid-immersed forced-liquid-cooled with liquid-to-water-cooler	0.0

E.5 Bibliography for Annex E

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Annex F

(normative)

Cold-load pickup (CLPU)

F.1 General

Cold-load pickup (CLPU) is the loading imposed on power and distribution transformers upon re-energization following a system outage. When an outage occurs, temperature in residential and office buildings starts to decay towards the outdoor ambient temperature. The amount of this decay and heat loss depends upon the temperature differential, the building insulation level, etc. Diversity among all the electric space heating furnaces and other appliances is rapidly lost. When the power is restored, all connected electric space heating furnaces, heaters, and other appliances will demand power simultaneously until the normal temperature conditions are attained and the diversity is regained. The time required to regain the diversity depends on the heating capacity of the furnaces and the duration of the preceding outage.

Obviously, the total loading imposed on the transformer after power restoration will be substantially higher than its normal peak load. Cold-load pickup consists of the following two components of the restoration load:

a) Inrush current associated with transformers, motor starting, etc. Although the magnitudes are quite large (in the order of 6 to 25 times the normal current), the duration is quite short, lasting a few cycles.

b) Load due to loss of diversity among thermostatically controlled cycling appliances. This load may persist for tens of minutes.

F.2 Duration of loads

Duration of this excessive load depends upon several variables, some of which are as follows:

– Time of and the day the outage begins

– Day of the week outage ends
– Duration of outage
– Temperature conditions and wind
– Number of customers affected by the outage
– Building size and insulation levels
– Type of load

This loading condition will persist until all the thermostatically controlled appliances are satisfied and the diversity has been restored. Typically, the maximum length of time during an outage until all diversity will be lost is around 20 min. The longer the outage lasts, the longer the load will remain undiversified after reenergization.

F.3 CLPU ratio

The ratio of the post-interruption load to pre-interruption load varies with the length and time of day of the interruption and the ambient temperature during interruption.

As an example, CLPU ratios that may be expected in a utility are as follows:

Load type	CLPU ratio
Major industrial	Less than 1.0
Residential plus 50% industrial	1–1.5
Urban residential plus less than 20% penetration of electric	1.5–2.0
Combination urban and rural	2.0–2.5
Rural	2.5–3.0

Different users will have different CLPU ratios depending upon their own customers and operating practices. Each user should look at the ratios for his or her system.

Studies (such as *Effects of the Cold Load Pickup at the Distribution Substation Transformer* [F2]) have shown that CLPU with high penetration of electric heating can become a limiting factor for substation transformers and for the protective equipment on the feeder. Electric heat penetration of 50–70% could lead to a CLPU ratio in the range of 3–4, or even higher.

Air conditioning could become a limiting factor if the penetration of air conditioning loads exceeds electric resistance space heating by a factor of 3 or more.

Depending upon normal loading of the transformer, it is possible to reach short-term emergency loading limits of the substation transformer. In some cases, it is possible for CLPU to exceed the thermal limits of a transformer resulting in associated loss of transformer insulation life.

During these types of loads, the auxiliary cooling equipment should be in operation. Since the duration of these loads is short or does not occur often, it is recommended that CLPU be considered as short-time emergency loading of the transformer.

F.4 Other considerations

Although CLPU has not been recognized as a serious problem in the past, changing patterns of oil and gas price and availability in several parts of the country have resulted in a continuing changeover from oil-based heating system to electric space heating system, making CLPU a more serious problem. In the substations where the transformers may be approaching their nameplate loading, it is worthwhile investigating the type of loads served to determine if a CLPU problem exists.

Depending upon circumstances, it may be necessary to restore the load in stages.

The effect of CLPU should be considered in the setting of relays, recloser trip settings, and fuse sizes to prevent nuisance tripping.

When planning capacity additions, utilities normally select the transformer capabilities to accommodate the anticipated load growth. It is recommended that effects of CLPU should also be considered during this planning. Application of loads in excess of nameplate when ambient temperatures are less than 0 °C requires consideration of transformer design, cooling control, and prior loading. Viscosity of the insulation fluid will influence velocity and distribution, and may detrimentally affect heat transfer. For power transformers with external cooling accessories, the method of control should be reviewed to ensure oil flow is induced before loading exceeds the respective ratings. If prior loading cannot be controlled by demand or rate of increase, the windings may experience localized hot spots and accelerated aging of conductor insulation during cold weather ambients.

F.5 Bibliography for Annex F

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Annex G

(informative)

Alternate temperature calculation method

G.1
General

The transformer loading equations in Clause 7 use the top-oil temperature rise over ambient to determine the winding hottest-spot temperature during an overload. When the equations were first proposed in 1945, there were few experimental investigations of the winding hottest-spot temperature during transient loading conditions. Recent investigations (Aubin and Langhame [G4], Pierce [G7]) have shown that during overloads, the temperature of the oil in the winding cooling ducts rises rapidly at a time constant equal to the winding. During this transient condition, the oil temperature adjacent to the hot spot location is higher than the top oil temperature in the tank. For the ONAN and ONAF cooling modes, this phenomena results in winding hottest-spot temperatures greater than predicted by the equations of Clause 7. Accurate predictions of the winding hottest-spot temperature require the use of the temperature of the oil entering and exiting the winding cooling ducts. ~~The equations in clause 7 also assume a constant ambient air temperature during a load cycle.~~ The equations presented in this annex consider type of liquid, cooling mode, winding duct oil temperature rise, resistance and viscosity changes, and ambient temperature and load changes during a load cycle. The derivation of the equations is given in Pierce [G8]. A PC Basic computer program is presented to perform the calculations in a step-by-step procedure.

Although the equations more exactly describe the heat transfer and fluid flow phenomena occurring in a liquid- immersed transformer during transient loading, they may not be equally valid for all distribution and power transformers covered by this guide and for all loading conditions. Recent research using imbedded thermocouples and fiber optic detectors indicate that the fluid flow occurring in the winding during transient heating and cooling is an extremely complicated phenomena to describe by simple equations. Research in this field is ongoing at this time and may be incorporated into future revisions of this guide.

G.2 List of symbols

Temperatures are indicated by Θ, and temperature rises or temperature differences are indicated by $\Delta\Theta$.

Equation	Program	Description
—	A	Aging acceleration factor
—	AEQ	Equivalent aging acceleration factor over a complete load cycle
—	ASUM	Equivalent insulation aging over load cycle, h
—	AMB( )	Ambient point on input of load cycle curve, °C
D	B	Constant in viscosity equation
G	C	Constant in viscosity equation
Cp_{CORE}	—	Specific heat of core, W-min/lb °C
Cp_{OIL}	CPF	Specific heat of fluid, W-min/lb °C
—	CPST	Specific heat of steel, W-min/lb °C
Cp_{TANK}	—	Specific heat of tank, W-min/lb °C
Cp_{W}	CPW	Specific heat of winding material, W-min/lb °C
E_{HS}	PUELHS	Eddy loss at winding hot spot location, per unit of I^2R loss
—	GFLUID	Fluid volume, gallons
H_H	HHS	Per unit of winding height to hot spot location
—	JJ	Number of points on load cycle
I	—	Rated current, A
K_H	TKHS	Temperature correction for losses at hot spot location
—	KK	Number of times results are printed
K_W	TKW	Temperature correction for losses of winding
—	LCAS	Loading case 1 or 2, see input data description in G.5
K	PL	ratio of load L to rated load, per unit
—	PUL( )	Per-unit load point on load cycle curve
—	MA	Cooling code, 1 = ONAN, 2 = ONAF, 3 = non-directed OFAF, 4 = directed ODAF
—	MC	Conductor code, l = aluminum, 2 = copper
—	MCORE	Core overexcitation occurs during load cycle, 0 = no, l = yes
—	MF	Fluid code, 1= mineral oil, 2 = silicone, 3 = HTHC
—	MPR1	Print temperature table, 0 = no, 1 = yes
—	MPR	Print temperature table, 0 = no, 1 = yes
M_{CC}	WCC	Core and coil (untanking) weight, lb
M_{CORE}	WCORE	Mass of core, lb

M_{OIL}	WFL	Mass of fluid, lb
M_{TANK}	WTANK	Mass of tank, lb
M_W	WWIND	Mass of windings, lb
$M_W Cp_W$	XMCP	Winding mass times specific heat, W-min /°C
ΣMCp	SUMMCP	Total mass times specific heat of fluid, tank, and core, W-min/°C
$P_{C,R}$	PC	Core (no-load) loss, W
$P_{C,OE}$	PCOE	Core loss when overexcitation occurs, W
P_E	PE	Eddy loss of windings at rated load, W
P_{EH}	PEHS	Eddy loss of windings at rated load and rated winding hot-spot temperature,
P_S	PS	Stray losses at rated load, W
P_T	PT	Total losses at rated load, W
P_W	PW	Winding I^2R loss at rated load, W
P_{HS}	PWHS	Winding I^2R loss at rated load and rated hot-spot temperature, W
Q_C	QC	Heat generated by core, W-min
$Q_{GEN,HS}$	QHSGEN	Heat generated at hot spot temperature, W-min
$Q_{GEN,W}$	QWGEN	Heat generated by windings, W-min

Equation	**Program**	**Description**
$Q_{LOST,\ HS}$	QLHS	Heat lost for hot-spot calculation, W-min
$Q_{LOST,\ O}$	QLOSTF	Heat lost by fluid to ambient, W-min
$Q_{LOST,\ W}$	QWLOST	Heat lost by winding, W-min
Q_S	QS	Heat generated by stray losses, W-min
—	RHOF	Fluid density, lb/in^3
—	SL	Slope of line between two load points of load cycle curve
—	SLAMB	Slope of line between two ambient temperature points of load cycle curve
Δt	DT	Time increment for calculation, min
—	DTP	Time increment for printing calculations, min
—	TIM( )	Value of time point on load cycle
—	TIMHS	Time during load cycle when maximum hot spot occurs, h

—	TIMP( )	Times when results are printed, min
—	TMP	Time to print a calculation, min
—	TIMCOR	Time when core overexcitation occurs, h
—	TIMTO	Time during load cycle when maximum top oil temperature occurs, h
—	TIMS	Elapsed time, min
	TIMSH	Elapsed time, h
x	\X	Exponent for duct oil rise over bottom oil, 0.5 for ONAN, ONAF, and OFAF, 1.0 for ODAF
y	YN	Exponent of average fluid rise with heat loss, 0.8 for ONAN, 0.9 for ONAF and ~~NDFOA,~~ OFAF, 1.0 for ~~DFOA~~ODAF
z	Z	Exponent for top to bottom fluid temperature difference, 0.5 for ~~OA~~ONAN and ~~FA,~~
Θ	T	Temperature to calculate viscosity, °C
Θ_A	TA	Ambient temperature, °C
$\Theta_{A,R}$	TAR	Rated ambient at kVA base for load cycle, °C
Θ_{BO}	TBO	Bottom fluid temperature, °C
$\Theta_{BO,R}$	TBOR	Bottom fluid temperature at rated load, °C
Θ_{DAO}	TDAO	Average temperature of fluid in cooling ducts, °C
$\Theta_{DAO,R}$	TDAOR	Average temperature of fluid in cooling ducts at rated load, °C
Θ_{TDO}	TTDO	Fluid temperature at top of duct, °C
$\Theta_{TDO,R}$	TTDOR	Fluid temperature at top of duct at rated load, °C
Θ_H	THS	Winding hottest-spot temperature, °C
—	THSMAX	Maximum hottest-spot temperature during load cycle, °C
$\Theta_{H,R}$	THSR	Winding hottest-spot temperature at rated load, °C
Θ_K	TK	Temperature factor for resistance correction, °C
—	TKHS	Correction factor for correction of losses to hot-spot temperature

Equation	Program	Description
—	TKVA1	Temperature base for losses at base kVA input, °C
—	TMU	Temperature in viscosity function, °C
Θ_{AO}	TFAVE	Average fluid temperature in tank and radiator, °C
—	TFAVER	Average fluid temperature in tank and radiator at rated load, °C
Θ_{TO}	TTO	Top fluid temperature in tank and radiator, °C
—	TTOMAX	Maximum top fluid temperature in tank during load cycle, °C
$\Theta_{TO,R}$	TTOR	Top fluid temperature in tank and radiator at rated load, °C
Θ_{W}	TW	Average winding temperature, °C
Θ_{WO}	TWO	Temperature of oil adjacent to winding hot spot, °C
$\Theta_{WO,R}$	TWOR	Temperature of oil adjacent to winding hot spot at rated load, °C
—	TWR	Rated Average winding temperature at rated load, °C
$\Theta_{W,R}$	TWRT	Average winding temperature at rated load tested, °C
$\Delta\Theta_{AO,R}$	—	Average oil rise over ambient at rated load, °C
$\Delta\Theta_{BO}$	—	Bottom fluid rise over ambient, °C
$\Delta\Theta_{BO,R}$	THEBOR	Bottom fluid rise over ambient at rated load, °C
$\Delta\Theta_{DO,R}$	THEDOR	Temperature rise of fluid at top of duct over ambient at rated load, °C
$\Delta\Theta_{DO/BO}$	DTDO	Temperature rise of fluid at top of duct over bottom fluid, °C
$\Delta\Theta_{H/A}$	THEHSA	Winding hottest-spot rise over ambient, °C
$\Delta\Theta_{H/WO}$	—	Winding hot-spot temperature rise over oil next to hot-spot location, °C
$\Delta\Theta_{T/B}$	DTTB	Temperature rise of fluid at top of radiator over bottom fluid, °C
$\Delta\Theta_{TO}$	—	Top fluid rise over ambient, °C
$\Delta\Theta_{TO,R}$	THETOR	Top fluid rise over ambient at rated load, °C
—	THKVA2	Rated ave. winding rise over ambient at kVA base of load cycle, °C
$\Delta\Theta_{W/A,R}$	THEWA	Tested or rated average winding rise over ambient, °C
$\Delta\Theta_{WO/BO}$	—	Temperature rise of oil at winding hot-spot location over bottom oil, °C
μ	FNV(B,C,T)	Viscosity, cP
μ_{HS}	VISHS	Viscosity of fluid for hot-spot calculation, cP
$\mu_{HS,R}$	VIHSR	Viscosity of fluid for hot-spot calculation at rated load, cP
μ_{W}	VIS	Viscosity of fluid for average winding temperature rise calc., cP
$\mu_{W,R}$	VISR	Viscosity of fluid for average winding temperature rise at rated load, cP
τ_{W}	TAUW	Winding time constant, min
—	XKVA1	kVA base for losses in input data
—	XKVA2	kVA base for load cycle curve

Suffixes	Description
1	At the prior time
2	At the next instant of time
R	At rated load
/	Over
Superscript	**Description**
(')	Indicates adjustment of test report data for a different tap position

Cooling modes	Description
ONAN	Natural convection flow of oil through windings and radiators. Natural convection flow of air over tank and radiators.
ONAF	Natural convection flow of oil through windings and radiators. Forced convection flow of air over radiators by fans.
ODAF	Forced oil flow through windings and radiators or heat exchanger by pumps. The oil is directed from the radiators or heat exchangers into the windings. The air is forced over the radiators or heat exchanger by fans.
OFAF	Forced oil flow through the radiators by one or more pumps. The oil is forced to flow into the tank by the pumps; however the main forced oil flow in the tank bypasses the windings. The air is forced over the radiators or heat exchangers by fans.

G.3 Equations

G.3.1 Introduction

The winding hottest-spot and oil temperatures are obtained from equations for the conservation of energy during a small instant of time, Δt. The system of equations constitutes a transient forward-marching finite difference calculation procedure. The equations were formulated so that temperatures obtained from the calculation at the prior time t_1 are used to compute the temperatures at the next instant of time $t_1 + \Delta t$ or t_2. The time is incremented again by Δt, and the last calculated temperatures are used to calculate the temperatures for the next time step. At each time step, the losses were calculated for the load and corrected for the resistance change with temperature. Corrections for fluid viscosity changes with temperature were also incorporated into the equations. With this approach, the required accuracy is achieved by selecting a small value for the time increment Δt and the programming approach is very simple. No iteration is required.

The improved system of loading equations is based on the fluid flow conditions occurring in the transformer during transient conditions. The hottest-spot temperature is made up of the following components.

$$\Theta_H = \Theta_A + \Delta\Theta_{BO} + \Delta\Theta_{WO/BO} + \Delta\Theta_{H/WO} \tag{G.1}$$

where

Θ_A is the average ambient temperature during the load cycle to be studied, °C

Θ_H is the winding hottest-spot temperature, °C

$\Delta\Theta_{BO}$ is the bottom fluid rise over ambient, °C

$\Delta\Theta_{WO/BO}$ is the temperature rise of oil at winding hot-spot location over bottom oil, °C

$\Delta\Theta_{H/WO}$ is the winding hot-spot temperature rise over oil next to hot-spot location, °C

The energy balance equation to determine the oil temperature was based on the average oil temperature in the tank and radiators. The temperatures of the top and bottom oil are determined from Equation (G.2) and Equation (G.3).

$$\Theta_{BO} = \Theta_{AO} - \frac{\Delta\Theta_{T/B}}{2} \tag{G.2}$$

$$\Theta_{TO} = \Theta_{AO} + \frac{\Delta\Theta_{T/B}}{2} \tag{G.3}$$

where

Θ_{AO} is the average fluid temperature in tank and radiator, °C

Θ_{BO} is the bottom fluid temperature, °C

Θ_{TO} is the top fluid temperature, °C

$\Delta\Theta_{T/B}$ is the temperature rise of fluid at top of radiator over bottom fluid, °C

For overload conditions, the oil temperature rise at the hottest-spot location $\Delta\Theta_{WO/BO}$ is the temperature rise of the oil in the winding cooling ducts above the bottom oil temperature. When the load is reduced, the winding duct oil temperature falls, but a portion of the upper winding may still remain in the hotter top oil of the main tank. When the winding duct oil temperature is less than the top oil in the main tank, $\Delta\Theta_{WO/BO}$ is assumed to equal the tank top-oil rise over the bottom oil.

G.3.2 Average winding temperature

The heat generated by the windings during the time t_1 to t_2 is

$$Q_{GEN,W} = K^2 \left[P_W K_W + \frac{P_E}{K_W} \right] \Delta t \tag{G.4}$$

where

K is the ratio of load L to rated load, per unit

K_W is the temperature correction for losses of winding

P_E is the eddy loss of windings at rated load, W

P_W is the winding I^2R loss at rated load, W

$Q_{GEN,W}$ is the heat generated by windings, W-min

Δt is the time increment for calculation, min

Where

$$K_W = \frac{\Theta_{W,1} + \Theta_K}{\Theta_{W,R} + \Theta_K} \tag{G.5}$$

where

K_W is the temperature correction for losses of winding

Θ_K is the temperature factor for resistance correction, °C

$\Theta_{W,1}$ is the average winding temperature at the prior time, °C

$\Theta_{W,R}$ is the average winding temperature at rated load tested, °C

For the ONAN, ONAF, and OFAF cooling modes, the heat lost by the windings is

$$Q_{LOST,W} = \left[\frac{\Theta_{W,1} - \Theta_{DAO,1}}{\Theta_{W,R} - \Theta_{DAO,R}} \right]^{5/4} \left[\frac{\mu_{W,R}}{\mu_{W,1}} \right]^{1/4} (P_W + P_E)\,\Delta t \tag{G.6A}$$

where

P_E is the eddy loss of windings at rated load, W

P_W is the winding I^2R loss at rated load, W

$Q_{LOST,W}$ is the heat lost by winding, W-min

$\Theta_{DAO,1}$ is the average temperature of fluid in cooling ducts at the prior time, °C

$\Theta_{DAO,R}$ is the average temperature of fluid in cooling ducts at rated load, °C

$\Theta_{W,1}$ is the average winding temperature at the prior time, °C

$\Theta_{W,R}$ is the average winding temperature at rated load tested, °C

Δt is the time increment for calculation, min

$\mu_{W,1}$ is the viscosity of fluid for average winding temperature rise at rated load at the prior time, cP

$\mu_{W,R}$ is the viscosity of fluid for average winding temperature rise at rated load, cP

The viscosity μ is evaluated at a temperature equal to the average winding temperature plus the average oil duct temperature divided by two.

For the ODAF cooling mode, no viscosity correction is used since the fluid is pumped and the heat lost is

$$Q_{LOST,W} = \left[\frac{\Theta_{W,1} - \Theta_{DAO,1}}{\Theta_{W,R} - \Theta_{DA(O,R)}} \right] (P_W + P_E)\,\Delta t \qquad \text{(G.6B)}$$

where

P_E is the eddy loss of windings at rated load, W

P_W is the winding I^2R loss at rated load, W

$Q_{LOST,\ W}$ is the heat lost by winding, W-min

$\Theta_{DAO,1}$ is the average temperature of fluid in cooling ducts at the prior time, °C

$\Theta_{DAO,R}$ is the average temperature of fluid in cooling ducts at rated load, °C

$\Theta_{W,1}$ is the average winding temperature at the prior time, °C

$\Theta_{W,R}$ is the average winding temperature at rated load tested, °C

Δt is the time increment for calculation, min

The mass and thermal capacitance of the windings may be estimated from the winding time constant. The winding time constant may be determined from the cooling curves obtained during factory heat run testing, or approximate values may be used. From the definition of a time constant for exponential heating or cooling the MCp term may be determined from Equation (G.7).

$$M_W Cp_W = \frac{(P_W + P_E)\,\tau_W}{\Theta_{W,R} - \Theta_{DAO,R}} \qquad \text{(G.7)}$$

where

$M_W Cp_W$ is the winding mass times specific heat, W-min/°C

P_E is the eddy loss of windings at rated load, W

P_W is the winding I^2R loss at rated load, W

$\Theta_{DAO,R}$ is the average temperature of fluid in cooling ducts at rated load, °C

$\Theta_{W,R}$ is the average winding temperature at rated load tested, °C

τ_W is the winding time constant, min

The average winding temperature at time $t = t_2$ is

$$\Theta_{W,2} = \frac{Q_{GEN,W} - Q_{LOST,W} + M_W Cp_W \Theta_{W,1}}{M_W Cp_W} \tag{G.8}$$

where

$M_W Cp_W$ is the winding mass times specific heat, W-min/°C

$Q_{GEN,W}$ is the heat generated by windings, W-min

$Q_{LOST,W}$ is the heat lost by winding, W-min

$\Theta_{W,1}$ is the average winding temperature at the prior time, °C

$\Theta_{W,2}$ is the average winding temperature at the next instant of time, °C

G.3.3 Winding duct oil temperature rise over bottom oil

$$\Delta\Theta_{DO/BO} = \Theta_{TDO} - \Theta_{BO} = \left[\frac{Q_{LOST,W}}{(P_W + P_E)\Delta t}\right]^x (\Theta_{TDO,R} - \Theta_{BO,R}) \tag{G.9}$$

where

P_E is the eddy loss of windings at rated load, W

P_W is the winding I^2R loss at rated load, W

$Q_{LOST,W}$ is the heat lost by winding, W-min

x is the exponent for duct oil rise over bottom oil, and is 0.5 for ONAN, ONAF, and OFAF, 1.0 for ODAF

Θ_{BO} is the bottom fluid temperature, °C

$\Theta_{BO,R}$ is the bottom fluid temperature at rated load, °C

Θ_{TDO} is the fluid temperature at top of duct, °C

$\Theta_{TDO,R}$ is the fluid temperature at top of duct at rated load, °C

$\Delta\Theta_{DO/BO}$ is the temperature rise of fluid at top of duct over bottom fluid, °C

Δt is the time increment for calculation, min

For the ONAN, ONAF, and ODAF cooling modes the duct top-oil temperature at rated load, $\Theta_{TDO,R}$ is assumed equal to the tank top oil temperature. For non-directed OFAF, if the duct top-oil temperature at rated load $\Theta_{TDO,R}$ is not known, it can be assumed to be approximately equal to the average winding temperature at rated load (based on an analysis of the data reported in Pierce [G7]).

In Pierce [G7], it is shown that the hot spot may not be located at the top of the winding. The oil temperature at the hot-spot elevation is given by

$$\Delta\Theta_{WO/BO} = H_{HS}(\Theta_{TDO} - \Theta_{BO}) \quad \text{(G.10)}$$

$$\Theta_{WO} = \Theta_{BO} + \Theta_{WO/BO} \quad \text{(G.11A)}$$

where

H_{HS} is the per unit of winding height to hot spot location
Θ_{BO} is the bottom fluid temperature, °C
Θ_{TDO} is the fluid temperature at top of duct, °C
Θ_{WO} is the temperature of oil adjacent to winding hot spot, °C
$\Theta_{WO/BO}$ is the temperature of oil at winding hot-spot location over bottom oil, °C
$\Delta\Theta_{WO/BO}$ is the temperature rise of oil at winding hot-spot location over bottom oil, °C

When the winding duct-oil temperature is less than the top oil in the tank, the oil temperature adjacent to the hot spot is assumed equal to the top-oil temperature since the upper portion of the winding may be in contact with the hotter top oil. The equation is as follows:

$$\text{IF } \Theta_{TDO} < \Theta_{TO} \text{ THEN } \Theta_{WO} = \Theta_{TO} \quad \text{(G.11B)}$$

Θ_{TDO} is the fluid temperature at top of duct, °C
Θ_{TO} is the top fluid temperature in tank and radiator, °C
Θ_{WO} is the temperature of oil adjacent to winding hot spot, °C

G.3.4 Winding hottest-spot temperature

To account for the additional heat generated at the hot-spot temperature, it is necessary to correct the winding losses from the average winding temperature to the hottest-spot temperature by means of the following equations:

$$P_{HS} = \left(\frac{\Theta_{H,R} + \Theta_K}{\Theta_{W,R} + \Theta_K} \right) P_W \tag{G.12}$$

$$P_{EHS} = E_{HS} P_{HS} \tag{G.13}$$

where

E_{HS} is the eddy loss at winding hot spot location, per unit of I^2R loss

P_{EHS} is the eddy loss at rated load and rated winding hot-spot temperature, W

P_{HS} is the Winding I^2R loss at rated load and rated hot spot temperature, W

P_W is the winding I^2R loss at rated load, W

Θ_K is the temperature factor for resistance correction, °C

$\Theta_{H,R}$ is the winding hottest-spot temperature at rated load, °C

$\Theta_{W,R}$ is the average winding temperature at rated load tested, °C

If E_{HS} is not known, it may be estimated; however, it should be equal to or greater than $P_{E,R}$ divided by $P_{W,R}$.

$$Q_{GEN,HS} = K^2 \left[P_{HS} K_{HS} + \frac{P_{EHS}}{K_{HS}} \right] \Delta t \tag{G.14}$$

where

K is the ratio of load L to rated load, per unit

K_{HS} is the temperature correction for losses at hot spot location

P_{EHS} is the eddy loss at rated load and rated winding hot-spot temperature, W

P_{HS} is the winding I^2R loss at rated load and rated hot spot temperature, W

$Q_{GEN,HS}$ is the heat generated at hot spot temperature, W-min

Δt is the time increment for calculation, min

where

$$K_{HS} = \frac{\Theta_{H,1} + \Theta_K}{\Theta_{H,R} + \Theta_K} \tag{G.15}$$

where

K_{HS} is the temperature correction for losses at hot spot location

Θ_K is the temperature factor for resistance correction, °C

$\Theta_{H,1}$ is the winding hottest-spot temperature at rated load at the prior time, °C

$\Theta_{H,R}$ is the winding hottest-spot temperature at rated load, °C

For the ONAN, ONAF, and OFAF cooling modes, the heat lost at the hot spot location is given by

$$Q_{LOST,HS} = \left[\frac{\Theta_{H,1} - \Theta_{WO}}{\Theta_{H,R} - \Theta_{WO,R}}\right]^{5/4} \left[\frac{\mu_{HS,R}}{\mu_{HS,1}}\right]^{1/4} (P_{HS} + P_{EHS})\,\Delta t \tag{G.16A}$$

where

P_{EHS} is the eddy loss at rated load and rated winding hot-spot temperature,

W P_{HS} is the winding I^2R loss at rated load and rated hot spot temperature,

W $Q_{LOST,\,HS}$ is the heat lost for hot-spot calculation, W-min

$\Theta_{H,1}$ is the winding hottest-spot temperature at the prior time, °C

$\Theta_{H,R}$ is the winding hottest-spot temperature at rated load °C

Θ_{WO} is the temperature of oil adjacent to winding hot spot, °C

$\Theta_{WO,R}$ is the temperature of oil adjacent to winding hot spot at rated load, °C

$\mu_{HS,1}$ Is the viscosity of fluid for hot-spot calculation at the prior time, cP

$\mu_{HS,R}$ Is the viscosity of fluid for hot-spot calculation at rated load, cP

Δt is the time increment for calculation, min

For the ODAF cooling mode, no viscosity correction is used since the oil is pumped and the heat lost at the hot-spot location is given by

$$Q_{LOST,HS} = \left[\frac{\Theta_{H,1} - \Theta_{WO}}{\Theta_{H,R} - \Theta_{WO,R}}\right] (P_{HS} + P_{EHS})\,\Delta t \tag{G.16B}$$

where

P_{EHS} is the eddy loss at rated load and rated winding hot-spot temperature, W

P_{HS} is the winding I^2R loss at rated load and rated hot spot temperature, W

$Q_{LOST,\,HS}$ is the heat lost for hot-spot calculation, W-min

$\Theta_{H,1}$ is the winding hottest-spot temperature at the prior time, °C

$\Theta_{H,R}$ is the winding hottest-spot temperature at rated load °C

Θ_{WO} is the temperature of oil adjacent to winding hot spot, °C

$\Theta_{WO,R}$ is the temperature of oil adjacent to winding hot spot at rated load, °C

Δt is the time increment for calculation, min

The winding hot-spot temperature at time t_2 is

where

$M_W Cp_W$ is the winding mass times specific heat, W-min/°C

$Q_{GEN,\,HS}$ is the heat generated at hot spot temperature, W-min

$Q_{LOST,\,HS}$ is the heat lost for hot-spot calculation, W-min

$\Theta_{H,1}$ is the winding hottest-spot temperature at the prior time, °C

$\Theta_{H,2}$ is the winding hottest-spot temperature at the next instant of time, °C

G.3.5 Average oil temperature

The heat lost by the windings to the duct oil and the heat generated by the core and stray losses is absorbed by the bulk oil in the main tank and radiators and is lost to the ambient air. The heat generated by the core varies slightly with temperature; however, it is assumed constant for the analysis. Overexcitation during the load cycle increases core loss however. The heat generated by the core is given by Equation (G.18A), Equation (G.18B), and Equation (G.19) as follows:

For normal excitation:

$$Q_C = P_{C,R}\,\Delta t \tag{G.18A}$$

where

$P_{C,R}$ is the core (no-load) loss, W

Q_C is the heat generated by core, W-min

Δt is the time increment for calculation, min

For overexcitation:

$$Q_C = P_{C,OE}\ \Delta t \tag{G.18B}$$

where

$P_{C,OE}$ is the core loss when overexcitation occurs, W

Q_C is the heat generated by core, W-min

Δt is the time increment for calculation, min

The heat generated by the stray loss is given by

$$Q_S = \left[\frac{K^2 P_S}{K_W}\right]\Delta t \tag{G.19}$$

where

K is the ratio of load L to rated load, per unit

K_W is the temperature correction for losses of winding

P_S is the stray losses at rated load, W

Q_S is the heat generated by stray losses, W-min

Δt is the time increment for calculation, min

The temperature correction, K_W for stray loss is given by Equation (G.5) and assumes that the temperature of the structural parts is the same as the average winding temperature.

The heat lost by the oil is given by Equation (G.20) and Equation (G.21) as follows:

$$P_T = P_W + P_E + P_S + P_C \tag{G.20}$$

where

P_C is the core (no-load) loss, W

P_E is the eddy loss of windings at rated load, W

P_S is the stray losses at rated load, W

P_T is the total losses at rated load, W

P_W is the winding I^2R loss at rated load, W

$$Q_{LOST,O} = \left[\frac{\Theta_{AO,1} - \Theta_{A,1}}{\Theta_{AO,R} - \Theta_{A,R}} \right]^{1/y} P_T \Delta t \tag{G.21}$$

where

P_T is the total losses at rated load, W

$Q_{LOST,O}$ is the heat lost by fluid to ambient, W-min

$\Theta_{A,1}$ is the ambient temperature at the prior time, °C

$\Theta_{A,R}$ is the rated ambient at kVA base for load cycle, °C

$\Theta_{AO,1}$ is the average fluid temperature in tank and radiator at the prior time, °C

$\Theta_{AO,R}$ is the average fluid temperature in tank and radiator at the rated load, °C

Δt is the time increment for calculation, min

y is the exponent of average fluid rise with heat loss, and is 0.8 for ONAN, 0.9 for ONAF and OFAF, and 1.0 for ODAF

To determine the core weight it is necessary to subtract the weight of the windings used in Equation (G.22) from the total core and coil weight given on the outline drawing supplied by the manufacturer.

$$M_W = \frac{M_W Cp_W}{Cp_W} \tag{G.22}$$

where

Cp_W is the specific heat of winding material, W-min/lb °C

$M_W Cp_W$ is the winding mass times specific heat, W-min/°C

M_W is the mass of windings, lb

$$M_{CORE} = M_{CC} - M_W$$

where

M_{CC} is the core and coil (untanking) weight, lb

M_{CORE} is the mass of core, lb

M_W is the mass of windings, lb

$$\sum MCp = M_{TANK}\,Cp_{TANK} + M_{CORE}\,Cp_{CORE} + M_{OIL}\,Cp_{OIL} \tag{G.24}$$

Where

CP_{CORE} is the specific heat of the core, W-min/lb °C

CP_{OIL} is the specific heat of fluid, W-min/lb °C

CP_{TANK} is the specific heat of the tank, W-min/lb °C

M_{CORE} is the mass of core, lb

M_{OIL} is the mass of fluid, lb

M_{TANK} is the mass of tank, lb

ΣMCp is the total mass times specific heat of oil, tank, and core, W-min/°C

The average oil temperature at time t_2 is given by

$$\Theta_{AO,2} = \frac{Q_{LOST,W} + Q_S + Q_C - Q_{LOST,O} + \left(\sum MCp\right)\Theta_{AO,1}}{\sum MCp} \tag{G.25}$$

where

$Q_{LOST,O}$ is the heat lost by fluid to ambient, W-min

$Q_{LOST,W}$ is the heat lost by winding, W-min

Q_C is the heat generated by core, W-min

Q_S is the heat generated by stray losses, W-min

ΣMCp is the total mass times specific heat of fluid, tank, and core, W-min/°C

$\Theta_{AO,1}$ is the average fluid temperature in tank and radiator at the prior time, °C

$\Theta_{AO,2}$ is the average fluid temperature in tank and radiator at the next instant of time, °C

The heat lost by the winding to oil is given by Equation (G.6).

G.3.6 Top and bottom oil temperatures

The top and bottom oil temperatures are determined by an equation similar to the equation for duct oil rise.

$$\Delta\Theta_{T/B} = (\Theta_{TO} - \Theta_{BO}) = \left[\frac{Q_{LOST,O}}{P_T\,\Delta t}\right]^z (\Theta_{TO,R} - \Theta_{BO,R}) \tag{G.26}$$

where

z is the exponent for top to bottom fluid temperature difference and is 0.5 for ONAN and ONAF; 1.0 for OFAF and ODAF

P_T is the total losses at rated load, W

$Q_{LOST,O}$ is the heat lost by fluid to ambient, W-min

$\Delta\Theta_{T/B}$ is the temperature rise of oil at top of radiator over bottom fluid, °C

Θ_{BO} is the bottom fluid temperature, °C

$\Theta_{BO,R}$ is the bottom fluid temperature at rated load, °C

Θ_{TO} is the top fluid temperature in tank and radiator, °C

$\Theta_{TO,R}$ is the top fluid temperature in tank and radiator at rated load, °C

Δt is the time increment for calculation, min

The heat lost by the oil, $Q_{LOST,O}$ is given by Equation (G.21). The top and bottom oil temperatures then are determined as follows from Equation (G.2) and Equation (G.3):

$$\Theta_{BO} = \Theta_{AO} - \frac{\Delta\Theta_{T/B}}{2}$$

$$\Theta_{TO} = \Theta_{AO} + \frac{\Delta\Theta_{T/B}}{2}$$

where

Θ_{AO} is the average fluid temperature in tank and radiator, °C

Θ_{BO} is the bottom fluid temperature, °C

Θ_{TO} is the top fluid temperature in tank and radiator, °C

$\Delta\Theta_{T/B}$ is the temperature rise of oil at top of radiator over bottom fluid, °C

G.3.7 Stability requirements

For the ONAN, ONAF, and OFAF cooling modes, the system of equations is stable if the following criteria are met.

$$\frac{\tau_W}{\Delta t} > \left[\frac{\Theta_{W,1} - \Theta_{DAO,1}}{\Theta_{W,R} - \Theta_{DAO,R}}\right]^{1/4} \left[\frac{\mu_{W,R}}{\mu_{W,1}}\right]^{1/4} \quad \text{(G.27A)}$$

where

$\Theta_{DAO,1}$ is the average temperature of fluid in cooling ducts at the prior time,
°C $\Theta_{DAO,R}$ is the average temperature of fluid in cooling ducts at rated load,
°C
$\Theta_{W,1}$ is the average winding temperature at the prior time, °C
$\Theta_{W,R}$ is the average winding temperature at rated load tested, °C
$\mu_{W,1}$ is the viscosity of fluid for average winding temperature rise at the prior time, cP
$\mu_{W,R}$ is the viscosity of fluid for average winding temperature rise at rated load, cP
τ_W is the winding time constant, min
Δt is the time increment for calculation, min

$$\frac{\tau_W}{\Delta t} > \left[\frac{\Theta_{H,1} - \Theta_{WO}}{\Theta_{H,R} - \Theta_{WO,R}}\right]^{1/4} \left[\frac{\mu_{HS,R}}{\mu_{HS,1}}\right]^{1/4} \quad \text{(G.27B)}$$

where

$\Theta_{H,1}$ is the winding hottest-spot temperature at the prior time, °C
$\Theta_{H,R}$ is the winding hottest-spot temperature at the rated load, °C
Θ_{WO} is the temperature of oil adjacent to winding hot spot, °C
$\Theta_{WO,R}$ is the temperature of oil adjacent to winding hot spot at rated load, °C $\mu_{HS,1}$ is the viscosity of fluid for hot-spot calculation at the prior time, cP
$\mu_{HS,R}$ is the viscosity of fluid for hot-spot calculation at rated load, cP

τ_W is the winding time constant, min

Δt is the time increment for calculation, min

and for ODAF

$$\frac{\tau_W}{\Delta t} > 1 \qquad \text{(G.27C)}$$

where

τ_W is the winding time constant, min

Δt is the time increment for calculation, min

For the computer program, a time increment of $\Delta t = 0.5$ min is used, and the following criteria used for stability and accuracy for all four cooling modes:

$$\frac{\tau_W}{\Delta t} > 9 \qquad \text{(G.27D)}$$

If required, the value of Δt is reduced to meet the stability requirement.

G.3.8 Fluid viscosity and specific heats of materials

Fluid viscosity is highly temperature dependant. The fluid viscosity at any temperature is given by an equation of the form

$$\mu = D\, e^{G/(\Theta + 273)} \qquad \text{(G.28)}$$

where

D is a constant (Table G.2)

G is a constant (Table G.2)

Θ is the temperature of oil to use for viscosity, °C

μ is the viscosity of oil, centipoises

The temperatures used to calculate the viscosity are given in Table G.1. Values of the constants D and G for three transformer fluids were derived from property data given in ASTM D3487 [G1], ASTM D4652 [G2], and ASTM D5222 [G3]. The values of these constants are given in Table G.2. Specific heats of materials vary only slightly with temperature so that a constant value may be used. Specific heats are given in Table G.2.

Table G.1—Temperatures for calculating viscosity

Equation number	Viscosity term	Temperature for calculation
G.6A	$\mu_{W,R}$	$(\Theta_{W,R} + \Theta_{DAO,R})/2$
G.6A	$\mu_{W,1}$	$(\Theta_{W,1} + \Theta_{DAO,1})/2$
G.16A	$\mu_{HS,R}$	$(\Theta_{H,R} + \Theta_{WO,R})/2$
G.16A	$\mu_{HS,1}$	$(\Theta_{H,1} + \Theta_{WO,1})/2$

Table G.2—Specific heat and constants for viscosity calculation

Material	Cp[a]	D	G
Oil	13.92	.0013573	2797.3
Silicone	11.49	.12127	1782.3
HTHC	14.55	.00007343	4434.7
Tank(steel)	3.51		
Core(steel)	3.51		
Copper	2.91		
Aluminum	6.80		

[a]W-min./lb °C

G.3.9 Summary of exponents

Values of the exponents used in the temperature calculations are summarized in Table G.3.

The computer program allows changing the *y* exponent for cases for which test data is available.

Table G. 3—Summary of exponents

Exponent	Used for	Cooling mode			
		ONAN	ONAF	OFAF	ODAF
x	Duct oil rise	0.5	0.5	0.5	1.0
y	Average oil rise	0.8	0.9	0.9	1.0
z	Top to bottom oil rise in Radiator	0.5	0.5	1.0	1.0

G.3.10 Adjustment of rated test data for a different tap position

If it is desired to adjust the test data for operation on a no-load tap position other than that reported on the test report, Equation (G.29) through Equation (G.31) may be used as follows~~:~~ in G.3.10.1.

G.3.10.1 Top- and bottom-oil rise over ambient

$$\Delta\Theta_{AO,R} = \frac{\Delta\Theta_{TO,R} + \Theta_{BO,R}}{2} \qquad (G.29)$$

where

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at rated load,
°C $\Delta\Theta_{BO,R}$ is the bottom fluid rise over ambient at rated
load, °C $\Delta\Theta_{TO,R}$ is the top fluid rise over ambient at rated
load, °C

$$\Delta\Theta'_{TO,R} = \Delta\Theta_{AO,R}\left[\frac{P'_{T,R}}{P_{T,R}}\right]^{y} + \left[\frac{\Delta\Theta_{TO,R} - \Delta\Theta_{BO,R}}{2}\right]\left[\frac{P'_{T,R}}{P_{T,R}}\right]^{z} \quad \text{(G.30)}$$

where

$P_{T,R}$ is the total losses at rated load, W

$P'_{T,R}$ is the total losses on a different tap, W

y is the exponent of average fluid rise with heat loss, and is 0.8 for ONAN, 0.9 for ONAF and OFAF, and 1.0 for ODAF

z is the exponent for top to bottom fluid temperature difference, 0.5 for ONAN and ONAF, 1.0 for OFAF and ODAF

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at rated load,

°C $\Delta\Theta_{BO,R}$ is the bottom fluid rise over ambient at rated

load, °C $\Delta\Theta_{TO,R}$ is the top fluid rise over ambient at rated

load, °C

$\Delta\Theta'_{TO,R}$ is the top fluid rise over ambient at rated load on a different tap, °C

$$\Delta\Theta'_{BO,R} = \Delta\Theta_{AO,R}\left[\frac{P'_{T,R}}{P_{T,R}}\right]^{y} - \left[\frac{\Delta\Theta_{TO,R} - \Delta\Theta_{BO,R}}{2}\right]\left[\frac{P'_{T,R}}{P_{T,R}}\right]^{z} \quad \text{(G.31)}$$

where

$P_{T,R}$ is the total losses at rated load, W

$P'_{T,R}$ is the total losses on a different tap, W

y is the exponent of average fluid rise with heat loss, and is 0.8 for ONAN, 0.9 for ONAF and OFAF, and 1.0 for ODAF

z is the exponent for top to bottom fluid temperature difference, 0.5 for ONAN and ONAF, 1.0 for OFAF and ODAF

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at rated load, °C

$\Delta\Theta_{BO,R}$ is the bottom fluid rise over ambient at rated load, °C

$\Delta\Theta'_{BO,R}$ is the bottom fluid rise over ambient at rated load on a different tap, °C$\Delta\Theta_{TO,R}$ is the top fluid rise over ambient at rated load, °C

G.3.10.2 Average winding rise over ambient

For ONAN, ONAF, and ODAF:

$$\Delta\Theta_{DO/BO,R} = \Delta\Theta_{TO,R} - \Delta\Theta_{BO,R} \qquad \text{(G.32A)}$$

where

$\Delta\Theta_{BO,R}$ is the bottom fluid rise over ambient at rated load, °C

$\Delta\Theta_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C

$\Delta\Theta_{TO,R}$ is the top fluid rise over ambient at rated load, °C

For OFAF:

$$\Delta\Theta_{DO/BO,R} = \Delta\Theta_{W/A,R} - \Delta\Theta_{BO,R} \qquad \text{(G.32B)}$$

where

$\Delta\Theta_{BO,R}$ is the bottom fluid rise over ambient at rated load, °C

$\Delta\Theta_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C

$\Delta\Theta_{W/A,R}$ is the tested or rated average winding rise over ambient, °C

Then

$$\Delta\Theta'_{DO/BO,R} = \Delta\Theta_{DO/BO,R}\left[\frac{I'_R}{I_R}\right]^{2x} \qquad \text{(G.33)}$$

where

I_R is the rated current at rated load, A

I'_R is the rated current at rated load at a different tap position, A

x is the exponent for duct oil rise over bottom oil, 0.5 for ONAN, ONAF, and OFAF, 1.0 for ODAF

$\Delta\Theta_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C

$\Delta\Theta'_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load at a different tap position, °C

For ONAN, ONAF, and OFAF:

$$\Delta\Theta'_{W/A,R} = \left[\Delta\Theta_{W/A,R} - \Delta\Theta_{BO,R} - \frac{\Delta\Theta_{DO/BO,R}}{2}\right]\left[\frac{I'_R}{I_R}\right]^{1.6} + \Delta\Theta'_{BO,R} + \frac{\Delta\Theta'_{DO/BO,R}}{2} \qquad \text{(G.34A)}$$

where

I_R is the rated current at rated load, A

I'_R is the rated current at rated load at a different tap position, A

$\Delta\Theta_{BO,R}$ is the bottom fluid rise over ambient at rated load, °C

$\Delta\Theta'_{BO,R}$ is the bottom fluid rise over ambient at rated load at a different tap position, °C

$\Delta\Theta_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C

$\Delta\Theta'_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load at a different tap position, °C

$\Delta\Theta_{W/A,R}$ is the tested or rated average winding rise over ambient, °C

$\Delta\Theta'_{W/A,R}$ is the tested or rated average winding rise over ambient at a different tap position, °C

For ODAF:

$$\Delta\Theta'_{W/A,R} = \left[\Delta\Theta_{W/A,R} - \Delta\Theta_{BO,R} - \frac{\Delta\Theta_{DO/BO,R}}{2}\right]\left[\frac{I'_R}{I_R}\right]^{2.0} + \Delta\Theta'_{BO,R} + \frac{\Delta\Theta'_{DO/BO,R}}{2} \qquad \text{(G.34B)}$$

where

I_R is the rated current at rated load, A

I'_R is the rated current at rated load at a different tap position, A

$\Delta\Theta_{BO,R}$ is the bottom fluid rise over ambient at rated load, °C

$\Delta\Theta'_{BO,R}$ is the bottom fluid rise over ambient at rated load at a different tap position, °C

$\Delta\Theta_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C

$\Delta\Theta'_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load at a different tap position, °C

$\Delta\Theta_{W/A,R}$ is the tested or rated average winding rise over ambient, °C

$\Delta\Theta'_{W/A,R}$ is the tested or rated average winding rise over ambient at a different tap position, °C

G.3.10.3 Hottest-spot rise over ambient

For ONAN, ONAF, and OFAF:

$$\Delta\Theta'_{H/A,R} = \left[\Delta\Theta_{H/A,R} - \Delta\Theta_{BO,R} - \Delta\Theta_{DO/BO,R}\right]\left[\frac{I'_R}{I_R}\right]^{1.6} + \Delta\Theta'_{BO,R} + \Delta\Theta'_{DO/BO,R} \qquad \text{(G.35A)}$$

where

I_R is the rated current at rated load, A

I'_R is the rated current at rated load at a different tap position, A

$\Delta\Theta_{BO,R}$ is the bottom fluid rise over ambient at rated load, °C

$\Delta\Theta'_{BO,R}$ is the bottom fluid rise over ambient at rated load at a different tap position, °C

$\Delta\Theta_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C

$\Delta\Theta'_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load at a different tap position, °C

$\Delta\Theta_{H/A,R}$ is the winding hottest-spot rise over ambient at rated load, °C

$\Delta\Theta'_{H/A,R}$ is the winding hottest-spot rise over ambient at rated load at a different tap position, °C

$$\Delta\Theta'_{H/A,R} = \left[\Delta\Theta_{H/A,R} - \Delta\Theta_{BO,R} - \Delta\Theta_{DO/BO,R}\right]\left[\frac{I'_R}{I_R}\right]^{2.0} + \Delta\Theta'_{BO,R} + \Delta\Theta'_{DO/BO,R} \qquad \text{(G.35B)}$$

where

I_R is the rated current at rated load

I'_R is the rated current at rated load at a different tap position

$\Delta\Theta_{BO,R}$ is the bottom fluid rise over ambient at rated load, °C

$\Delta\Theta'_{BO,R}$ is the bottom fluid rise over ambient at rated load at a different tap position, °C

$\Delta\Theta_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load, °C

$\Delta\Theta'_{DO/BO,R}$ is the temperature rise of fluid at top of duct over bottom fluid at rated load at a different tap position, °C

$\Delta\Theta_{H/A,R}$ is the winding hottest-spot rise over ambient at rated load, °C

$\Delta\Theta'_{H/A,R}$ is the winding hottest-spot rise over ambient at rated load at a different tap position, °C

G.3.11 Load cycles and ambient temperatures

Values for the per-unit load and ambient temperature are obtained from a plot or table. In the computer program, the load cycle is described by the end points of straight lines where the load or ambient temperature plot changes slope.

Figure G.1 and the input data file is an example of this concept. This method more accurately describes the variation of load than the step load change or rms method of Clause 7. Values may be input for any number of load points.

G.4 Discussion

The equations require the use of the bottom oil rise over ambient at rated conditions. Reference IEEE Std C57.12.90-1993 [G5] requires that this measurement be made during thermal testing; however, the measurement is not normally reported on the transformer test report. For existing units, the data may be obtained from the manufacturer. Specifications for new transformers should require that both the top and bottom oil temperature rises be stated on the test report.

The exponents in the equations were derived from fluid flow and heat transfer principles. The value of the *y* exponent depends upon the relative contribution of radiation, natural convection, and forced air heat losses and some variation between units. The computer program allows changing the value of the y exponent. Data for the *y* exponent may be obtained from overload heat run in accordance with IEEE Std C57.119 [G6]. It is recommended that no changes be made in the other exponents.

The equations consider a variable ambient during the load cycle. Loading capability as a function of ambient may be determined with the equations. The equation formulation assumes that the temperature of the top oil in the tank and radiators are equal. During cold start-up at temperatures below about –20 °C, the oil in the main tank may become considerable hotter than the oil in the radiator. This depends upon the tank and radiator configuration. This condition is not considered in the equations.

Overexcitation of the core is considered in the program to allow predictions of oil and winding temperatures. Overexcitation may increase core loss several times above rated. Overexcitation above 110% of rated may result in core saturation and excessive local overheating. This is not considered. The loading equations also separate eddy and stray losses from losses due to winding resistance. This will permit a future consideration of oil and winding heating effects due to increased stray and eddy losses when harmonic currents are present. Local overheating due to stray losses in the structural parts or the tank may also occur, and this local overheating is not considered in the loading equations. Other subclauses of the guide should be consulted for other loading limitations.

Thermal testing in accordance with IEEE Std C57.12.90-1993 [G5] is performed by the short-circuit method, which gives zero core loss. The effect of core loss on the oil temperature is determined by holding above rated current. The computer program listed later was developed for loading of in-service transformers with core loss present. To compare the program predictions with the results of overload thermal tests, zero core loss should be used as input and the per-unit loads based on the currents should be held during the various tests.

G.5 Disclaimer statement

This computer program is an essential part of IEEE Std C57.91-~~1995.~~2011. This computer program may be copied, sold, or included with software that is sold as long as Annex G of IEEE Std C57.91-2011 is cited as the source. This computer program may be used to implement this standard and may be distributed in source code or compiled form in any manner. This file may be copied for individual use by users who have purchased this standard.

The IEEE disclaims any responsibility or liability for damages resulting from misinterpretation or misuse of said information by the user.

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G.6 Computer program Input data for computer program

Line numbers are used for convenience. They must be used, but have no significance. Reference to instruction numbers refer to the following instructions for data input and default values for unknown data.

1,

kVA base for losses ,

Temperature base for losses at this kVA, °C ,

I^2R losses, P_W, W (see instruction a) ,

Winding eddy losses, P_E, W (see instruction a) ,

Stray losses, P_S, W (see instruction a) ,

Core loss, $P_{C,R}$,W ,

2,

One per unit kVA base for load cycle ,

Data at this kVA (temperatures and temperature rises in °C):

Rated average winding rise over ambient ,

Tested or rated average winding rise over ambient, $\Delta\Theta_{W/A,R}$,

Tested or rated hot-spot rise over ambient, $\Delta\Theta_{H/A,R}$,

Tested or rated top-oil rise over ambient, $\Delta\Theta_{TO,R}$,

Tested or rated bottom oil rise over ambient, $\Delta\Theta_{BO,R}$,

Rated ambient temperature, $\Theta_{A,R}$,

3,

Winding conductor, 1 = aluminum, 2 = copper ,

Per unit eddy loss at winding hot-spot, E_{HS} (see instruction b) ,

Winding time constant, τ_W, minutes (See instruction c) ,

Per unit winding height to hot spot, H_{HS} (see instruction d) ,

4,

Weight of core and coils, M_{CC}, lb ,

Weight of tank and fittings, M_{TANK}, lb ,

Type fluid, 1 =oil, 2=silicone, 3=HTHC ,

Gallons of fluid ,

(See instruction e) 5,

Over excitation occurs, 0 = no, 1 = yes ,

Time when over excitation occurs, h ,

Core loss during overexcitation, $P_{C,OE}$, W ,

6,

Loading case, 1 or 2

For case 1 the loading cycle (usually 24 h)
is assumed to repeat and the initial temperatures are not known.
For case 2, the initial temperatures (see instruction f) are input at line 7.

NOTE — Line 7 data must be input for case 2 and must not be input for case 1.

7,

(See instruction f)

Initial winding hottest-spot temperature, Θ_{HS}, °C ,

initial average winding temperature, Θ_{W}, °C ,

Initial top-oil temperature, Θ_{TO},°C ,

Initial top-duct-oil temperature, Θ_{TDO}, °C ,

Initial bottom-oil temperature, Θ_{BO}, °C ,

8,

Type cooling for load cycle, 1 = ONAN, 2 = ONAF, 3 = non-directed OFAF, 4 = directed ODAF ,

Print temperature table, 0=no, 1=yes ,

Time increment for printing, minutes ,

Number of points on load cycle ,

Data for load cycle, time in hours, ambient in °C (see instruction g):

10,time(1),ambient(1),per-unit load(1)

11,time(2),ambient(2),per-unit load(2)

12,time(3),ambient(3),per-unit load(3)…

xx,time (last),ambient (last),per-unit load (last)

The following are instructions for data input and default values for unknown data:

a) Stray losses and winding eddy losses vary inversely with temperature. The total stray and eddy loss may be obtained by calculating total I^2R using the resistance data from the total load loss. The computer program calculates a ratio of instantaneous losses to rated losses to determine the various temperature components. Since stray and eddy losses vary inversely with temperature, it is conservative to assume zero winding eddy loss, that is, the ratio is higher when zero eddy losses are assumed. If resistance data is not available or if a calculation of I^2R is not made, it is conservative to input total load losses for I^2R loss and zero values for winding eddy loss and stray loss.

b) If the per unit eddy loss at the winding hot-spot location is unknown, use zero. This gives conservative results for the reasons given in instruction a).

c) Typical values of the winding time constant are 3–7 min. Estimates may be obtained from resistance cooling curve data from thermal testing. Overloads greater than 1/2 h have a minor effect on the hottest-spot temperature calculation. If the time constant is unknown, 5 min is suggested.

d) If the location of the winding hottest spot is unknown, input 1.00 for per unit winding height to the hottest- spot location. Values less than 1.00 are used to compare predicted hot spot temperatures with tested values in test windings with imbedded thermocouples or transformers with fiber optic hotspot detectors.

e) If overexcitation does not occur, input zero for time overexcitation and normal excitation core loss for core loss during overexcitation.

f) Case 1 is used for repeating load cycles (usually 24 h) such as planned overloading. Case 2 is used for short- time loading or emergency load cycles that do not repeat and may last less than 24 h. For case 2, the initial temperatures are determined by running a case 1 analysis and using the final temperatures as initial temperatures in line 7 for a case 2 analysis. For convenience, the computer program output lists final temperatures in the same order needed for input in line 7.

g) For repeating load cycles, data statements for 0 h and the last time input are equal unless a step load change occurs at zero time. Step changes in load are illustrated by the following example. Assume that the load increases from 0.7 to 1.5 at time 1 h with the ambient of some value, say 30 °C. Two sequential lines of data for the one hour point are required as follows:

xx1.0,30.0

,70

xx,l.0,30.0

,1.5

Program example:

It is desired to evaluate the load capability of a transformer rated ONAN/ONAF/ONAF-T-60-28000/37333/46667/52267-138000-34500Y/19919 for a summer load cycle with a maximum ambient of 40 °C and a peak load of 1.1. The losses on the test report are given at 28 000 kVA and 75 °C as follows:

No load 36 986
W Load loss 72
768 W Total loss
109 755

From the resistance data the I^2R losses are calculated to be 51 690 W. Thus, total stray and eddy loss is 72 768– 51 690 or 21 078 W. The temperature rise data at 52 267 kVA and the weights and fluid quantity are given as follows.

Core and coil weight, lb	75,600
Tank and radiators, lb	31,400
Gallons of oil	4,910
Temperature rises at 52,267 kVA, °C:	
Average wdg. guar.	65
Average wdg. test	63
Hottest spot	80
Top oil	55
Bottom oil	25

Values for the per-unit load and ambient are obtained from a plot of the load cycle. Values may be input for any number of load points. A plot of the load cycle is shown in Figure G.1.

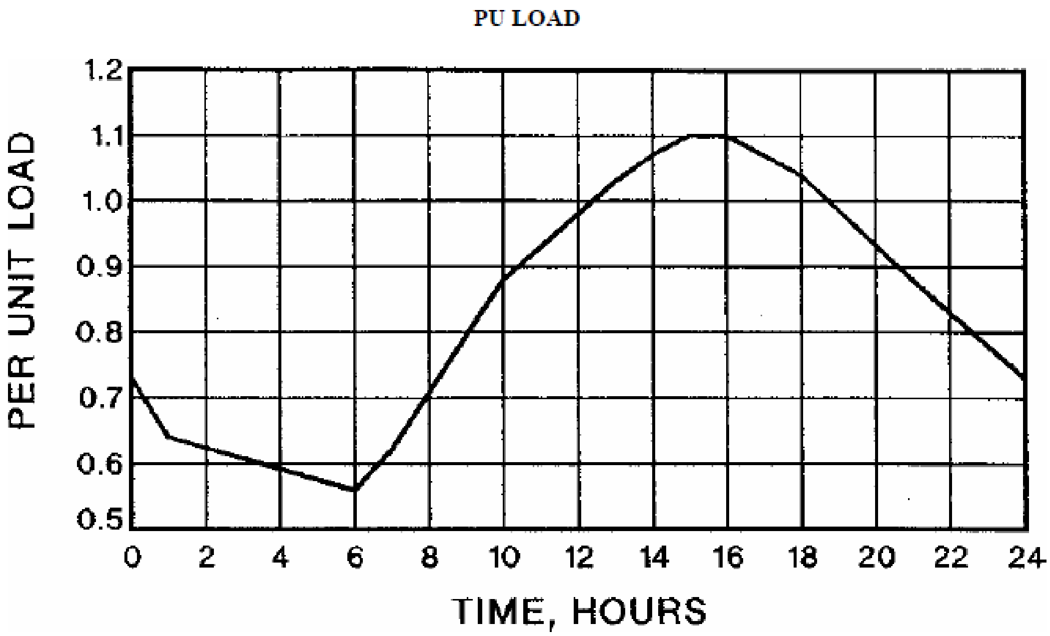

Figure G.1—Example load cycle

The input data file is shown below. The program output file is printed on the following pages. Input data file:

Input data file:

1,28000,75.,51690,0,21078,36986

2,52267,65,63.0,80,55.0,25.0,30.0

3,2,0,5,1.00

4,75600,31400,1,4910

5,0,0,36986

6,1

9,2,1,60,12

10,0,30.0, .73

11,1,29.5, .64

12,6,28.2, .56

13,7,29.8, .62

14,10,35.9, .88

15,13,39.6,1.03

16,14,40,1.07

17,15,40,1.10

18, 16,39.6,1.10

19,18,36.8,1.04

20,21,32.5, .88

21,24,30.0, .73

Output data file from program:

PROGRAM LOADT, VERSION 1.1, 9-15-1993

TRANSFORMER TEMPERATURE CALCULATION WITH VARIABLE LOAD AND AMBIENT TEMPERATURE USING BOTTOM OIL RISE DUCT OIL RISE, RESISTANCE CHANGE WITH TEMPERATURE CORRECTIONS FOR FLUID VISCOSITY FOR ONAN, ONAF, AND NON-DIRECTED OFAF COOLING MODES. NO VISCOSITY CORRECTION FOR DIRECTED ODAF COOLING MODE.

INPUT DATA FILENAME IS LCYC

OUTPUT DATA FILENAME IS

LCYCOUT

KVA BASE FOR LOSS INPUT DATA = 28000

TEMPERATURE BASE FOR LOSS INPUT DATA = 75 C

WINDING I SQUARE R = 51690 WATTS WINDING EDDY LOSS = 0 WATTS

STRAY LOSSES = 21078 WATTS

CORE LOSS = 36986 WATTS

TOTAL LOSSES = 109754 WATTS

WINDING CONDUCTOR IS COPPER

PER UNIT EDDY LOSS AT HOT SPOT LOCATION = 0

WINDING TIME CONSTANT = 5 MINUTES PER UNIT WINDING

HEIGHT TO HOT SPOT = 1

WEIGHT OF CORE & COILS = 75600 POUNDS WEIGHT OF TANK AND FITTINGS = 31400 POUNDS GALLONS OF FLUID = 4910

COOLING FLUID IS TRANSFORMER OIL

ONE PER UNIT LOAD. = 52267 KVA

FORCED AIR (ONAF)

COOLING

EXPONENT OF LOSSES FOR AVERAGE FLUID RISE = 0.9

AT THIS KVA LOSSES AT 95 C ARE AS FOLLOWS: WINDING I SQUARE R = 191752.2 WATTS WINDING EDDY LOSS = 0 WATTS

STRAY LOSSES = 68988.03 WATTS

CORE LOSSES = 36986 WATTS TOTAL LOSS = 297726.3 WATTS

AT THIS KVA INPUT DATA FOR TEMPERATURES AS FOLLOWS:

RATED AVERAGE WINDING RISE OVER AMBIENT = 65 °C

TESTED AVERAGE WINDING RISE OVER AMBIENT = 63 °C

HOTTEST SPOT RISE OVER AMBIENT = 80 °C

TOP FLUID RISE OVER AMBIENT = 55 °C BOTTOM FLUID RISE OVER AMBIENT = 25 °C RATED AMBIENT TEMPERATURE = 30 °C

CORE OVEREXCITATION DOES NOT OCCUR

(LOAD-TEMPERATURE TABLE ON PAGE TWO)

Load temperature able

Time Hours	PU Load	AMB Temp	HS Temp	TOPO Temp	TOPDO Temp	BOTO Temp
0.000	0.730	30.0	89.9	74.1	69.6	48.0
1.000	0.640	29.5	82.7	69.5	64.0	45.0
2.000	0.624	29.2	77.9	65.4	60.5	42.4
3.000	0.608	29.0	74.5	62.5	58.1	40.6
4.000	0.592	28.7	71.9	60.3	56.2	39.3
5.000	0.576	28.5	69.7	58.6	54.6	38.2
6.000	0.560	28.2	67.8	57.2	53.2	37.3
7.000	0.620	29.8	68.7	56.6	54.9	37.7
8.000	0.707	31.8	73.7	58.5	59.3	39.7
9.000	0.793	33.9	82.4	62.7	65.2	42.9
10.000	0.880	35.9	92.3	68.5	72.2	47.1
11.000	0.930	37.1	100.4	74.9	78.4	51.3
12.000	0.980	38.4	108.0	80.9	84.3	55.4
13.000	1.030	39.6	115.7	86.6	90.1	59.5
14.000	1.070	40.0	122.3	92.0	95.3	63.1
15.000	1.100	40.0	127.7	96.6	99.5	66.1
16.000	1.100	39.6	130.0	99.8	101.7	68.0
17.000	1.070	38.2	128.4	100.8	101.1	68.2
18.000	1.040	36.8	125.7	99.6	98.9	66.9
19.000	0.987	35.4	121.0	96.7	94.8	64.6
20.000	0.933	33.9	115.1	92.6	89.8	61.3
21.000	0.880	32.5	108.6	87.9	84.4	57.7
22.000	0.830	31.7	102.1	83.0	79.2	54.3
23.000	0.780	30.8	95.9	78.4	74.3	51.1
24.000	0.730	30.0	89.9	74.1	69.6	48.0

TEMPERATURES DURING LOAD CYCLE:

MAX. HOT SPOT TEMP. = 130.0855 AT 16.08333 HOURS MAX.

TOP FLUID TEMP. = 100.7999 AT 16.85 HOURS

FINAL HOT SPOT TEMP. = 89.9446

FINAL AVE. WIND. TEMP. = 73.36386

FINAL TOP OIL TEMP. = 74.08505

FINAL DUCT OIL TEMP. = 69.60123

FINAL BOT. OIL TEMP. = 48.01001

EQUIVALENT AGING = 36.22312 HOURS

LOAD CYCLE DURATION = 24 HOURS

EQUIVALENT AGING FACTOR = 1.509297 PER UNIT

Program listing:

```
10 REM PROGRAM LOADT,9-15-1993
20 DEFINT I-N:DIM TIM(100),PUL(100),AMB(100),TIMP(1500)
30 PRINT "ENTER INPUT DATA FILENAME"
40 INPUT F2$
50 PRINT "ENTER OUTPUT FILENAME"
60 INPUT F1$
70 OPEN F2$ FOR INPUT AS #2
80 OPEN F1$ FOR OUTPUT AS #1
90 INPUT #2, LN,XKVA1,TKVA1,PW,—PE,PS,PC
100 INPUT #2, LN, XKVA2,THKVA2,THEWA,THEHSA,THETOR,THEBOR,TAR
110 INPUT #2, LN,MC,PUELHS,TAUW,HHS
120 INPUT #2, LN,WCC,WTANK,MF,GFLUID
130 INPUT #2, LN,MCORE,TIMCOR,—PCOE
140 INPUT #2, LN, LCAS
150 ON LCAS GOTO 170,160
160 INPUT #2, LN, THS,TW,TTO,TTDO,TBO
170 INPUT #2, LN,MA,MPR1,DTP,JJ
180 FOR J=l TO JJ
```

```
190 INPUT #2, LN,TIM(J),AMB(J),PUL(J)
200 TIM(J)=60!*TIM(J)
210 NEXT J
220 CLOSE #2
230 PT=PW+PE+PS+PC
240 PRINT #1, "PROGRAM LOADT, VERSION 1.1, 9-15-1993"
250 PRINT #1,"TRANSFORMER TEMPERATURE CALCULATION WITH VARIABLE"
260 PRINT #1,"LOAD AND AMBIENT TEMPERATURE USING BOTTOM OIL RISE"
270 PRINT #1,"DUCT OIL RISE, RESISTANCE CHANGE WITH TEMPERATURE"
280 PRINT #1,"CORRECTIONS FOR FLUID VISCOSITY FOR ONAN, ONAF, AND NON-"
290 PRINT #1,"DIRECTED OFAF COOLING MODES. NO VISCOSITY CORRECTION"
300 PRINT #1,"FOR DIRECTED ODAF COOLING MODE."
310 PRINT #1,
320 PRINT #1,"INPUT DATA FILENAME IS ";F2$
330 PRINT #1,"OUTPUT DATA FILENAME IS ";F1$
340 PRINT #1,
350 PRINT #1,"KVA BASE FOR LOSS INPUT DATA = ";XKVA1
360 PRINT #1,"TEMPERATURE BASE FOR LOSS INPUT DATA = ";TKVA1;"C"
370 PRINT #1,"WINDING I SQUARE R = ";PW;"WATTS"
380 PRINT #1,"WINDING EDDY LOSS = ";PE;"WATTS"
390 PRINT #1,"STRAY LOSSES = ";PS;"WATTS"
400 PRINT #1,"CORE LOSS = ";PC;"WATTS"
410 PRINT #1,"TOTAL LOSSES = ";PT;"WATTS"
420 PRINT #1,
430 ON MC GOTO 440,460
440 PRINT #1,"WINDING CONDUCTOR IS ALUMINUM"
450 TK=225!:CPW=6.798:GOTO 480
460 PRINT #1,"WINDING CONDUCTOR IS COPPER"
470 TK=234.5:CPW=2.91
480 PRINT #1,"PER UNIT EDDY LOSS AT HOT SPOT LOCATION = ";PUELHS
490 PRINT #1,"WINDING TIME CONSTANT = ";TAUW;"MINUTES"
500 PRINT #1,"PER UNIT WINDING HEIGHT TO HOT SPOT = ";HHS
510 PRINT #1,
520 PRINT #1,"WEIGHT OF CORE & COILS = ";WCC;"POUNDS"
530 PRINT #1,"WEIGHT OF TANK AND FITTINGS = ";WTANK;"POUNDS"
540 PRINT #1,"GALLONS OF FLUID = ";GFLUID
550 ON MF GOTO 560,580,600
560 CPF=13.92:RHOF=.031621:C=2797.3:B=.0013473
```

```
570 PRINT #1, “COOLING FLUID IS TRANSFORMER OIL”:GOTO 620
580 CPF=11.49:RHOF=.0347:C=1782.3:B=.12127
590 PRINT #1, “COOLING FLUID IS SILICONE”:GOTO 620
600 CPF=14.55:RHOF=.03178:C=4434.7:B=7.343E-05
610 PRINT #1, “COOLING FLUID IS HTHC”
620 PRINT #1,
630 PRINT #1,“ONE PER UNIT LOAD. = ”;XKVA2;“ KVA”
640 ON MA GOTO 650,680,710,740
650 X=.5:YN=.8:Z=.5:THEDOR=THETOR
660 PRINT “COOLING MODE IS ONAN”
670 PRINT #1, “COOLING MODE IS ONAN”:GOTO 770
680 X=.5:YN=.9:Z=.5:THEDOR=THETOR
690 PRINT “COOLING MODE IS ONAF”
700 PRINT #1, “FORCED AIR (ONAF) COOLING”:GOTO 770
710 X=.5:YN=.9:Z=1!:THEDOR=THEWA
720 PRINT “COOLING MODE IS NON-DIRECTED OFAF”
730 PRINT #1, “NON-DIRECTED FORCED OIL (OFAF) COOLING”:GOTO 770
740 X=1! :YN=1! :Z=1! :THEDOR=THETOR
750 PRINT “COOLING MODE IS DIRECTED ODAF”
760 PRINT #1, “DIRECTED FORCED OIL COOLING (ODAF)”
770 PRINT “NOMINAL VALUE OF Y EXPONENT IS”;YN
780 PRINT “DO YOU WISH TO CHANGE? TYPE Y FOR YES OR N FOR NO”
790 INPUT F3$
800 IF F3$ = “Y” THEN GOTO 820
810 GOTO 840
820 PRINT “INPUT DESIRED VALUE OF Y EXPONENT”
830 INPUT YN
840 PRINT “PROGRAM IS RUNNING”
850 PRINT #1, “EXPONENT OF LOSSES FOR AVERAGE FLUID RISE = ”;YN
860 TWR=TAR+THKVA2:TWRT=TAR+THEWA
870 THSR=TAR+THEHSA:TTOR=TAR+THETOR
880 TBOR=TAR+THEBOR: TTDOR=THEDOR+TAR
890 TWOR=(HHS* (TTDOR-TBOR) )+TBOR
900 TDAOR=(TTDOR+TBOR) /2! :TFAVER=(TTOR+TBOR) /2!
910 XK2=(XKVA2/XKVA1)^2! :TK2=(TK+TWR)/(TK+TKVA1)
920 PW=XK2*PW*TK2:PE=XK2*PE/TK2:PS=XK2*PS/TK2
930 PT=PW+PE+PS+PC
940 IF (PE/PW)>PUELHS THEN PUELHS=PE/PW
```

```
950 TKHS=(THSR+TK) / (TWR+TK) :PWHS=TKHS*PW
960 PEHS=PUELHS* PWHS
970 PRINT #1, "AT THIS KVA LOSSES AT";TWR;"C ARE AS FOLLOWS:"
980 PRINT #1,"WINDING I SQUARE R = ";PW;"WATTS"
990 PRINT #1,"WINDING EDDY LOSS = ";PE;"WATTS"
1000 PRINT #1,"STRAY LOSSES = ";PS;"WATTS"
1010 PRINT #1,"CORE LOSSES = ";PC;"WATTS"
1020 PRINT #1,"TOTAL LOSS = ";PT;"WATTS":PRINT #1,
1030 PRINT #1,"AT THIS KVA INPUT DATA FOR TEMPERATURES AS FOLLOWS:
1040 PRINT #1,"RATED AVERAGE WINDING RISE OVER AMBIENT = ";THKVA2;"C"
1050 PRINT #1,"TESTED AVERAGE WINDING RISE OVER AMBIENT = ";THEWA;"C"
1060 PRINT #1,"HOTTEST SPOT RISE OVER AMBIENT = ";THEHSA;"C"
1070 PRINT #1,"TOP FLUID RISE OVER AMBIENT = ";THETOR;"C"
1080 PRINT #1,"BOTTOM FLUID RISE OVER AMBIENT = ";THEBOR;"C"
1090 PRINT #1,"RATED AMBIENT TEMPERATURE = ";TAR;"C"
1100 IF MCORE<1 GOTO 1140
1110 PRINT #1,"CORE OVEREXCITATION OCCURS AT ";TIMCOR;"HOURS"
1120 PRINT #1,"CORE OVEREXCITATION LOSS IS ";PCOE;"WATTS"
1130 GOTO 1150
1140 PRINT #1,"CORE OVEREXCITATION DOES NOT OCCUR"
1150 IF MPR1<1 GOTO 1230
1160 PRINT #1,
1170 PRINT #1, "(LOAD-TEMPERATURE TABLE ON PAGE TWO)"
1180 FOR I=l TO 15
1190 PRINT #1,
1200 NEXT I
1210 PRINT #1, " LOAD TEMPERATURE TABLE"
1220 PRINT #1,
1230 TIMCOR=60*TIMCOR
1240 DT=. 5
1250 IF (TAUW/DT)>9! THEN GOTO 1270
1260 DT=DT/2!:GOTO 1250
1270 XMCP=(PE+PW)*TAUW/(TWRT-TDAOR) :WWIND=XMCP/CPW
1280 IF WWIND>WCC THEN GOTO 2260
1290 WCORE=WCC-WWIND:CPST=3.51:WFL=GFLUID*231*RHOF
1300 SUMMCP=(WTANK*CPST)+(WCORE*CPST)+(WFL*CPF)
1310 DEF FNV(B,C,TMU)=B*EXP(C/(TMU+273!))
1320 T=(TWRT+TDAOR)/2! :VISR=FNV(B,C,T)
```

```
1330 T= (THSR+TWOR) /2! :VIHSR=FNV(B, C, T)
1340 TMP=0!:IF MPR1<1 THEN DTP=15
1350 KK=INT((TIM(JJ)/DTP)+.01)
1360 FOR K=1 TO KK
1370 TMP=TMP+DTP:TIMP(K) =TMP
1380 NEXT K
1390 PRINT #1,
1400 C$="##.### ##.### ##.# ###.# ###.# ###.# ###.#"
1410 IF MPR1<1 THEN GOTO 1450
1420 PRINT #1, " TIME PU AMB HS TOPO TOPDO BOTO"
1430 PRINT #1, "HOURS LOAD TEMP TEMP TEMP TEMP TEMP"
1440 PRINT #1,
1450 ON LCAS GOTO 1460,1480
1460 THS=THSR:TW=TWRT:TTO=TTOR:TTDO=TTDOR:TBO=TBOR
1470 PR =0:JLAST=2:GOTO 1490
1480 MPR=MPR1 : JLAST=1
1490 TFAVE= (TTO+TBO)/2! :TWO=TBO+ (HHS* (TTDO-TBO))
1500 FOR JJJ=1 TO JLAST
1510 IF JJJ=2 THEN MPR=MPR1
1520 THSMAX=THS :TIMHS=0 :TTOMAX=TTO :TIMTO=0
1530 J=1:K=1:TIMS=0! :TIMSH=0! :ASUM=0!
1540 IF MPR<1 THEN GOTO 1560
1550 PRINT #1, USING C$;TIMSH, PUL(1),AMB(1),THS,TTO,TTDO,TBO
1560 TIMS=TIMS+DT
1570 IF TIMS>TIM(J+1) THEN J=J+l
1580 IF TIMS>TIM(JJ) THEN GOTO 2120
1590 TIMSH=TIMS/60!
1600 IF ABS (TIM(J+l)-TIM(J))<.01 THEN J=J+l
1610 SL=(PUL(J+1)-PUL(J))/(TIM(J+1)-TIM(J))
1620 PL=PUL(J)+(SL*(TIMS-TIM(J)) )
1630 SLAMB=(AMB(J+1)-AMB(J))/(TIM(J+1)-TIM(J))
1640 TA=AMB(J)+(SLAMB*(TIMS-TIM(J)))
1650 TDAO=(TTDO+TBO)/2!
1660 TKW= (TW+TK)/(TWR+TK)
1670 QWGEN=PL*PL*((TKW*PW)+(PE/TKW))*DT
1680 IF TW<TDAO THEN GOTO 1750
1690 ON MA GOTO 1700,1700,1700,1730
1700 T=(TW+TDAO)/2! :VIS=FNV(B,C,T)
```

```
1710 QWLOST=(((TW-TDAO)/(TWRT-TDAOR))^1.25)*((VISR/VIS)^.25)*(PW+PE)*DT
1720 GOTO 1770
1730 QWLOST=((TW-TDAO)/(TWRT-TDAOR))*(PW+PE)*DT
1740 GOTO 1770
1750 QWLOST=0!
1760 IF TW<TBO THEN TW=TBO
1770 TW= (QWGEN-QWLOST+(XMCP*TW))/XMCP
1780 DTDO=(TTDOR-TBOR)* ((QWLOST/((PW+PE)*DT) )^X)
1790 TTDO=TBO+DTDO:TDAO=(TTDO+TBO)/2!
1800 TWO=TBO+(HHS*DTDO) :TKHS=(THS+TK)/(THSR+TK)
1810 IF (TTDO+.1)<TTO THEN TWO=TTO
1820 IF THS<TW THEN THS=TW
1830 IF THS<TWO THEN THS=TWO
1840 QHSGEN=PL*PL*((TKHS*PWHS)+(PEHS/TKHS))*DT
1850 ON MA GOTO 1860,1860,1860,1890
1860 T=(THS+TWO)/2! :VISHS=FNV(B,C,T)
1870 QLHS=(((THS-TWO)/(THSR-
TWOR))^1.25)*((VIHSR/VISHS)^.25)*(PWHS+PEHS)*DT
1880 GOTO 1900
1890 QLHS=((THS-TWO)/(THSR-TWOR))*(PWHS+PEHS)*DT
1900 THS= (QHSGEN-QLHS+(XMCP*THS))/XMCP
1910 QS=((PL*PL*PS)/TKW)*DT
1920 QLOSTF=(((TFAVE-TA)/(TFAVER-TAR))^(1/YN))*PT*DT
1930 IF MCORE<1 THEN GOTO 1960
1940 IF TIMS<TIMCOR THEN GOTO 1960
1950 QC=PCOE*DT: GOTO 1970
1960 QC=PC*DT
1970 TFAVE=(QWLOST+QC+QS-QLOSTF+(SUMMCP*TFAVE))/SUMMCP
1980 DTTB=((QLOSTF/(PT*DT))^Z)*(TTOR-TBOR)
1990 TTO=TFAVE+(DTTB/2!) :TBO=TFAVE-(DTTB/2!)
2000 IF TBO<TA THEN TBO=TA
2010 IF TTDO<TBO THEN TTDO=TBO
2020 AX=(15000!/383!)-(15000!/(THS+273!))
2030 A=EXP(AX) :ASUM=ASUM+(A*DT)
2040 IF THS<THSMAX THEN GOTO 2060
2050 THSMAX=THS:TIMHS=TIMSH
2060 IF TTO<TTOMAX THEN GOTO 2080
2070 TTOMAX=TTO: TIMTO=TIMSH
```

```
2080 IF TIMS<TIMP(K) THEN GOTO 1560
2090 IF MPR<1 THEN GOTO 2110
2100 PRINT #1, USING C$; TIMSH, PL, TA, THS, TTO, TTDO, TBO
2110 K=K+1: GOTO 1560
2120 NEXT JJJ
2130 TIMS=TIMS-DT: ASUM=ASUM/60! : AEQ=ASUM/TIMSH:_PRINT #1,
2140 PRINT #I,"TEMPERATURES DURING LOAD CYCLE:"
2150 PRINT #1, "MAX. HOT SPOT TEMP. ="; THSMAX; "AT"; TIMHS; "HOURS"
2160 PRINT #1, "MAX. TOP FLUID TEMP. ="; TTOMAX; "AT"; TIMTO; "HOURS"
2170 PRINT #1, PRINT #1, "FINAL HOT SPOT TEMP. ="; THS
2180 PRINT #1, "FINAL AVE. WIND. TEMP. ="; TW
2190 PRINT #1, "FINAL TOP OIL TEMP. ="; TTO
2200 PRINT #1, "FINAL DUCT OIL TEMP. ="; TTDO
2210 PRINT #1, "FINAL BOT. OIL TEMP. ="; TBO:_PRINT #1,
2220 PRINT #1, "EQUIVALENT AGING ="; ASUM; "HOURS"
2230 PRINT #1, "LOAD CYCLE DURATION ="; TIMSH; "HOURS"
2240 PRINT #1, "EQUIVALENT AGING FACTOR ="; AEQ; "PER UNIT"
2250 GOTO 2290
2260 PRINT "WINDING TIME CONSTANT TOO HIGH"
2270 PRINT #1, "CHANGE INPUT TO LOWER VALUE"
2280 PRINT "CHANGE INPUT TO LOWER VALUE IN INPUT FILE";_F2$
2290 CLOSE #1
2300 END
```

G.7 Bibliography for Annex G

[G1] ASTM D3487, *Standard Specification for Mineral Oil in Electrical Apparatus*.

[G2] ASTM D4652, *Standard Specification for Silicone Fluid Used for Electrical Insulation*.

[G3] ASTM D5222), *Standard Specification for High Fire-Point Mineral Electrical Insulating Oils*.

[G4] Aubin, J., and Langhame, T., *Effect of Oil Viscosity on Transformer Loading Capability at Low Ambient Temperatures,* IEEE Transactions on Power Delivery, vol. 7, no. 2, pp. 516–524, April 1992.

[G5] IEEE Std C57.12.90-1993, *IEEE Standard Test Code for Liquid-Immersed Distribution, Power, and Regulating Transformers.*

[G6] IEEE Std C57.11-2001, IEEE Recommended Practice for Performing Temperature Rise Tests on Oil-Immersed Power Transformers at Loads Beyond Nameplate Rating.

[G7] Pierce, L. W., *An Investigation of the Thermal Performance of an Oil Filled Transformer Winding*, IEEE Transactions on Power Delivery, vol. 7, no. 3, pp. 1347–1358, July 1992.

[G8] Pierce, L. W., *Predicting Liquid Filled Transformer Loading Capability*, IEEE Transactions on Industry Applications, vol. 30, no. 1, pp. 170–178, Jan./Feb. 1994.

Annex H

(normative)

Operation with part or all of the cooling out of service

H.1 General

Where auxiliary equipment, such as pumps or fans, or both, is used to increase the cooling efficiency, the transformer may be required to operate for some time without this equipment functioning. The permissible loading under such conditions is given in the following clauses.

H.2 ONAN/ONAF transformers

Some manufactures use a large number of small fans and others use a small number of large fans. If the number of fans inoperative is a large percentage of the total, use the self-cooled (ONAN) rating. For some designs only one or two inoperative fans may result in loss of significant cooling capacity.

H.3 ONAN/ONAF/ONAF, ONAN/ONAF/OFAF, and NAN/OFAF/OFAF transformers

For triple rated forced-air, forced-oil-cooled transformers with all or part of the cooling inoperative use the nameplate rating based on the full stage of cooling remaining in operation, or if less than a full stage of fan and pump cooling is operative, use the self-cooled (ONAN) rating. For loss of either fans or pumps on a stage of cooling, use the rating that pertains to total loss of that stage of cooling. For large units with a large number of fans, the loss of one or two fans will result in minimal temperature increase. For non-directed OFAF units, the loss of one or more pumps with the fans still in operation results in an increase in tank top oil, which gives increased temperatures for bushings, cables, and other ancillary components; however, the increase in winding hot-spot rise may not be significant.

H.4 OFAF and OFWF transformers

H.4.1 General

In general, the heat exchangers used to cool OFAF and OFWF type transformers will dissipate only an insignificant amount of heat when either the forced-oil circulation or the forced cooling medium (air or water) are inoperative. If only part of the coolers is inoperative, then refer to H.5 for load capability. If all of the coolers are inoperative, loading amounts and durations can be calculated as in H.4.2.

The amount of load carried, the duration of the load, the previous loading condition, the ambient temperature, and the physical parameters of the transformer determine its hottest-spot temperature and the loss-of-life experienced during the period of loss of all cooling. The user should calculate in accordance with the method below and refer to other pertinent clauses of this guide to determine the effects of the operating condition. During the period of loss of all cooling, the only significant amount of heat dissipated by the transformer will depend on tank radiation and its convection characteristics, which, in turn, are dependent on tank dimensions. Heat dissipation characteristics may be calculated from measurements obtained by measuring the actual unit or from estimations based on the transformer outline drawings.

H.4.2 Calculations

An approximation of the effect of loading and time upon the oil and hottest-spot temperature can be determined as shown in this clause. More accurate data may be obtained from the manufacturer.

H.4.2.1 Equations

1) Estimate the losses in watts that will be dissipated by the tank at the 100% OFAF oil rise after loss of all cooling as follows:

$$q_{TANK} = (0.00365)(0.155 \times S)(\Delta\Theta_{AO,R})^{1.21} \quad \text{(H.1)}$$

where

q_{TANK} is the losses dissipated by the tank at reference temperature rise $\Delta\Theta_{AO,R}$, W

S is the sum of surface areas of tank walls and cover neglecting braces, appurtenances, etc., cm^2

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C

2) Estimate the ultimate rise of average oil for the load that is to be maintained as follows:

$$\Delta\Theta_{AO,U} = \left(\frac{P_T}{q_{TANK}}\right)^{0.8} \Delta\Theta_{AO,R} \tag{H.2}$$

where

P_T is the total losses in watts, at load to be maintained

q_{TANK} is the losses dissipated by the tank at reference temperature rise $\Delta\Theta_{AO,R}$, W

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C $\Delta\Theta_{AO,U}$ is the ultimate rise of average oil over ambient, °C

3) The time constant corresponding to this loading condition should be calculated as follows:

$$\tau_L = \frac{C\left[\Delta\Theta_{AO,U} - \Delta\Theta_{AO,R}\right]}{P_T - q_{TANK}} \tag{H.3}$$

where

C is the thermal capacity as defined in Equation (13A) or Equation (13B)

P_T is the total losses in watts, at load to be maintained

q_{TANK} is the losses dissipated by the tank at reference temperature rise $\Delta\Theta_{AO,R}$

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C

$\Delta\Theta_{AO,U}$ is the ultimate rise of average oil over ambient, °C

τ_L is the oil time constant corresponding to loading condition, h

4) The average oil rise at any time t for the transformer in this operating mode can be estimated from the following formula:

$$\Delta\Theta_{AO} = \left(\Delta\Theta_{AO,U} - \Delta\Theta_{AO,R}\right)\left(1 - e^{\frac{-t}{\tau_L}}\right) + \Delta\Theta_{AO,R} \quad \text{(H.4)}$$

where

t is the time, h

$\Delta\Theta_{AO}$ is the difference in top oil temperature and average oil temperature, °C

The estimated top-oil rise can then be determined as follows:

$$\Delta\Theta_{TO} = \Delta\Theta_{TO-AO} + \Delta\Theta_{AO} \quad \text{(H.6)}$$

where

$\Delta\Theta_{AO}$ is the average oil rise over ambient at time t, °C

$\Delta\Theta_{TO}$ is the top-oil temperature rise over ambient, °C

$\Delta\Theta_{TO-AO}$ is the difference in top oil temperature and average oil temperature, °C

It is recommended that $\Delta\Theta_{TO} + \Theta_A$ not exceed 110 °C.

Estimates of top-oil rises at t/τ_L greater than 0.15 will have to be obtained from the manufacturer.

The hottest-spot rise above top-oil temperature, for directed oil flow units, will increase substantially when the forced-oil flow is stopped. An estimate of this rise can be obtained from the manufacturer. On the premise that some reasonable oil circulation will continue by natural convection, a rough estimate can be made as shown in the paragraphs that follow.

For nondirected flow, OFAF:

where

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C

$\Delta\Theta_{H,R}$ is the hottest-spot conductor rise over top-oil temperature at rated load, °C

$\Delta\Theta_{W/A}$ is the average winding temperature rise over ambient, °C

For directed flow, ODAF:

$$\Delta\Theta_{H,R} = 2.0\left(\Delta\Theta_{W/A} - \Delta\Theta_{AO,R}\right) + 5 \qquad \text{(H.7B)}$$

where

$\Delta\Theta_{AO,R}$ is the average oil rise over ambient at maximum nameplate rating obtained from factory test data, °C

$\Delta\Theta_{H,R}$ is the hottest-spot conductor rise over top-oil temperature at rated load

$\Delta\Theta_{W/A}$ is the average winding temperature rise over ambient, °C

And then,

$$\Delta\Theta_{H} = \Delta\Theta_{H,R} K^{2m} \qquad \text{(H.8)}$$

where

K is the ratio of load to be carried to 100% OFAF nameplate rating

m is an empirically derived exponent used to calculate the variation of $\Delta\Theta_H$ with changes in load. The value of m has been selected for each mode of cooling to approximately account for effects of changes in resistance and oil viscosity with changes in load. See Table 4.

$\Delta\Theta_H$ is the hottest-spot rise above top-oil rise at load to be maintained, °C

$\Delta\Theta_{H,R}$ is the hottest-spot conductor rise over top-oil temperature at rated load, °C

The average winding rise and average oil rise should be obtained from the certified test reports for the maximum nameplate rating.

The hottest-spot temperature at the load to be maintained can be estimated as follows:

$$\Theta_H = \Theta_A + \Delta\Theta_{TO}\Delta\Theta_H \tag{H.9}$$

where

Θ_A is the ambient temperature, °C

Θ_H is the hottest-spot temperature, °C

$\Delta\Theta_H$ is the hottest-spot rise above top-oil rise at load to be maintained, °C

$\Delta\Theta_{TO}$ is the top-oil temperature rise over ambient, °C

It is recommended that Θ_H not exceed 140 °C.

H.4.3 Caution

In using the equations in H.4.2.1, the following factors should be considered during a loss of cooling situation as follows:

a) Much of the normal overload protection (overcurrent relay, etc.) installed on a transformer will be inadequate for this operating condition.

b) The hottest-spot relay (for alarm and in many cases trip), using the two input parameters of phase current and top-oil temperature, is calibrated to a hottest-spot rise over oil with forced-oil circulation in the windings. It will indicate a temperature many degrees lower than actual hottest-spot temperature if there is no forced oil flow in the windings.

c) If the transformer is of directed flow design and pumps have been lost, it may be necessary to hold top-oil temperature well below normal to keep the hottest-spot temperature within its limitation, since, with drastically reduced oil flow, the hottest-spot gradient is greatly increased. Hence, the top-oil temperatures shall be kept lower to stay within the design hottest-spot limitation.

H.5 Forced-oil-cooled transformers with part of coolers in operation

For forced-oil-cooled (OFAF or OFWF) transformer ratings, with part of the coolers in operation, use the reductions in permissible loading given in Table H.1. These permissible loads will give approximately the same temperature rise as full load with all cooling in operation.

Table H.1—Loading capability for OFAF or OFWF transformers

% of total coolers in operation	Permissible load in % of nameplate rating
100	100
80	90
60	78
50	70
40	60
33	50

Annex I

(informative)

Transformer insulation life

I.1 Historical perspectives

In past versions of the guides for loading transformers, much space was dedicated to the subject of "loss-of-life." The background of this term was not always well understood. Many engineers assumed incorrectly that the "life" in "loss-of-life" referred to the transformer's life. From the beginning, the important modifier "insulation" frequently has been omitted from the phrase, "loss-of-life." Actually, loss-of-life has always meant "loss-of-insulation life." Because this distinction is so important, the user should review the following discussion of the history of loss-of-insulation life.

In the 1920s, but reported in 1930, Montsinger [I17] placed varnished cambric tape insulation into a series of oil-filled test tubes, heated them, and then measured the insulation's tensile strength. He reported that the life of the varnished cambric was reduced by one half for each 8 °C increase in continuous temperature. The "end-of-life" was defined as the point where the tensile strength of the varnished cambric reached 50% of its initial value. The loss of 50% of initial tensile strength end point was probably chosen because tensile strength was easy to measure. It also varied in about the same manner as other mechanical properties of the early insulations. This is not true of many of the insulating coatings, etc., in common use today. This was an initial signal for engineers to use their slide rules (later calculators and now computers) to make calculations of the expected life of a transformer's insulation at various operating temperatures to many significant figures beyond the accuracy of the input data.

The end-of-life of a transformer is not determined by a 50% reduction in the tensile strength of its insulation. It has been obvious for some time that transformers with residual insulation tensile strengths well below 20% of initial operate in a completely satisfactory manner. Lamentably, the industry gave far too much credence to Montsinger's test tube work. In 1944, Montsinger [I18] stated that one should not use aging data at higher temperatures and that the 8 °C rule was incorrect for lower temperatures. He also said, "There is, of course, some question whether laboratory aging tests made on isolated strips of paper in sealed tubes can be applied directly in estimating the life of insulation in a transformer." Unfortunately, the transformer industry apparently has seemed to ignore this statement.

Later, Dakin [I7] postulated that transformer insulation deteriorated following a modification of Arrhenius' chemical reaction rate theory. Dakin was probably correct, and a simple "insulation" life curve was developed to relate the insulation's life at a test temperature to an operating temperature. The industry took Dakin's work and, unfortunately, Montsinger's residual tensile strength end-of-insulation life end point and arrived at loss-of-life percentages (without the insulation modifier) based on time at various temperatures. These percentages were badly flawed due to the poorly selected end point; yet, with some slight modifications, they still appeared in recent loading guides without that all-–important "insulation" modifier. This happened in spite of a contemporary 1947 paper by Satterlee and Reed [I19] whose tests showed that insulation, in a sealed tank of oil with no load but exposed to ambient temperatures only, experienced a reduction of tensile strength to 20% of initial in about 2.5 years.

The data on the loss-of-insulation life curves shown in the different guides differed considerably. For example, although both distribution and power transformers use the same insulation, the loss-of-insulation life curves in the guides show a considerable variation for a specific temperature. The insulation life of distribution transformers is listed as being several times greater than the power transformer's guide insulation life.

In summary, loss-of-life data in previous guides was based, in part, on observations made 60–70 years ago, on obsolete materials, test tube data, and an inferior refined oil. In addition, the original investigator repudiated the data in the 1940s.

In the mid-1950s, a task force of the AIEE Transformers Committee composed of the manufacturers and users of distribution and power transformers undertook the most comprehensive examination of transformer life to date.

Sample distribution transformers of each manufacture were subjected to a series of carefully selected loading tests at a number of different manufacturing locations. The data from each of the investigators was coded to preserve the supplier's identity and sent to a neutral data compiler for review by the task force. It was initially planned by the task force to subject the transformer test models to alternate back-to-back loading and cooling cycles at three carefully determined hottest-spot conductor temperatures to determine their straight line life characteristic in accordance with reaction rate theory. The temperatures selected were 220 °C, 180 °C, and 140 °C. The test duration at each temperature was determined by current theory. The temperature was controlled by a monitor of exactly the same design containing thermocouples located throughout the windings and tank. After thermal cycling, each test model received "product" tests; the monitor received no product tests except oil analysis. The test end point was established as failure during any one of the product tests.

The 220 °C models were aged first to obtain a better estimate of the test duration for subsequent temperatures. To the surprise of many task force members, the 220 °C models survived many more cycles than expected. The variability between manufacturers was quite large as expected. The next series at 180 °C hottest-spot temperature was started at lengthened test duration and sure enough, the models continued to pass test cycle after cycle beyond expectation. Using end point times from the very first 180 °C failures to be reported, the task force predicted both an unacceptably long test cycle for the 140 °C models and a projected standard "life" exceeding hundreds of thousands of hours at normal rated temperature. Many manufacturers discontinued the 180 °C cycles. Others continued to run the tests for their own purposes. Although the end point tests included impulse and low-frequency withstands and short-circuit and visual examination, many of the investigators reported short circuits particularly in the end turns as the ultimate failure mode. Investigation showed this to be true long after nearly total dielectric strength reduction of the insulating system.

Since at least three test temperatures were not obtained from which to extrapolate the life characteristics of the tested systems; and as the "end-of-life" points reached at the 220 °C and 180 °C aging temperatures were significantly longer than anticipated, the task force, after much discussion, arbitrarily redefined the life curve for distribution transformers and supported the subsequent recommendation of the even more conservative power transformer life line.

A careful review of this history has been coupled with recent findings based on work done on model power transformers on two extensive EPRI transformer loading research projects ([I2], [I3]). Some results of this review have been as follows:

a) The reviewers have decided that the insulation life curves for distribution and power transformers are similar.
b) The insulation life curves for distribution and for power transformers, which were found in their respective previous guides, are not appropriate for modern transformer loading guides, but should be included in a future revision of IEEE Std C57.100 for thermal evaluation comparisons of the new insulation system.
c) The chemical test measurement of degree of polymerization (DP) is a much better indication of cellulosic insulation mechanical characteristics than loss of tensile strength.

I.2 Thermal aging principles

The principal constituent of most transformer conductor insulation materials is cellulose, an organic compound whose molecule is made up of a long chain of glucose rings or monomers (Fabre and Pinchon [I8], Shroff and Stannet [I20], Lampe and Spicar [I12], Beavers, Rabb, and Leslie [I5]. Degree of molecular polymerization refers to the average number of glucose rings in the molecule and it typically ranges from 1000–1400 for new material. A single cellulose fiber will contain many of these long chains and the mechanical strength of the fiber, and hence of its parent material, is closely related to the length of the chains. Thus, the degree of polymerization is a good measure of retained strength and functionality of cellulose.

As cellulose ages thermally in an operating transformer, three mechanisms contribute to its degradation, namely hydrolysis, oxidation, and pyrolysis (Shroff and Stannet [I20], Lampe and Spicar [I12]). The agents responsible for the respective mechanisms are water, oxygen, and heat. Each of these agents will have an effect on degradation rate so they must be individually controlled. Water and oxygen content of the insulation can be controlled by the transformer oil preservation system, but control of heat is left to transformer operating personnel.

Since the early days of transformer manufacture, the deterioration of mechanical properties as a result of thermal aging has been recognized. Montsinger [I17] published early aging data and made an observation about the aging rate that has been widely used. He noted that the rate of deterioration of mechanical properties doubled for each 5–10 °C increase in temperature. The doubling factor was not a constant, being about 6 °C in the temperature range from 100–110 °C and 8 °C for temperatures above 120 °C. However, people tend to remember the doubling factor as a constant and the present IEC Loading Guide [I11] uses 6 °C.

In 1948, Dakin [I7] made a more significant advance in defining insulation aging rates by recognizing that aging of cellulose is the result of a chemical reaction, so the rate of change of a measured property can be expressed in the form of a reaction rate constant K_o. This can be applied by multiplying the rate constant, a function of temperature, by the time interval over which the aging takes place to find the percentage change in a property. Mathematically, the rate constant can be expressed by

$$K_O = A' e^{\left[\frac{B}{\Theta + 273}\right]} \tag{I.1}$$

where

A' and B are empirical constants

Θ is the temperature in °C

Dakin showed that all aging rate data being compared in an AIEE committee, including Montsinger's data, could fit this relationship. The Dakin relationship, sometimes referred to as the Arrhenius reaction rate equation, has found wide acceptance in the world technical community in the ensuing years.

When the approach discussed is to be used for transformer life definition, there are two aspects involved, the first being the aging rate and the second being the life end-point criterion. These may be separated by treating life as a per unit quantity with the following as a life definition~~:~~

$$Per\ Unit\ Life = A\, e^{\left[\frac{B}{\Theta_H + 273}\right]} \tag{I.2}$$

where

A is a modified per unit constant, derived from the selection of 110 °C as the temperature established for "one per unit life"

B is the same aging rate slope as Equation (I.1)

Θ_H is the hottest-spot temperature, °C

This equation expresses the dependence of the aging rate on temperature alone, and the absolute definition of "one per unit life" in units of time can encompass the end-point criterion and the other variables that affect the time to reach that end point, namely water and oxygen content of the insulation system. Each of these aspects may be discussed separately.

Many investigators have measured cellulose aging rates under controlled conditions and have presented their results in the above form. Some measured mechanical properties, some measured DP, and some measured gas evolution rates. To use the reaction rate constant for loading guide purposes, it is desirable to select a single rate slope, the constant B, which would be reasonably accurate for all forms of cellulose. Table I.1 represents the results of a search of the published literature to find that slope.

Dakin's and Sumner's data appear to have been shared within an AIEE committee. Head's observations were most interesting in that he found that the *B* constants for mechanical properties (tensile strength, burst strength, elongation to rupture), DP and gas evolution were all the same within a range of ±440. Most of these data appear to be for non- thermally upgraded paper, but Lampe also evaluated thermally upgraded paper. His *B* constant in the table is one of the lowest, but his constant for thermally upgraded paper was even lower (9820). This could be the result of a limited temperature range of measurement, 135 °C–155 °C, from which it would be difficult to find an accurate slope. In recent evaluations to qualify thermally upgraded papers in the U.S. the data falls reasonably close to the slope of IEEE Std C57.92-1981. It should be pointed out that the ASA C57.92-1948 curve was not an Arrhenius curve, so it does not have a single value of *B* for all temperatures.

Source	**Basis**	***B***
Dakin [I7]	20% tensile strength retention	18 000
Sumner, et al. [I21]	20% tensile strength retention	18 000
Head, et al. [I10]	Mechanical/DP/gas evolution	15 250
Lawson, et al. [I14]	10% tensile strength retention	15 500
Lawson, et al. [I14]	10% DP retention	11 350
Shroff [I20]	250 DP	14 580
Lampe, et al. [I13]	200 DP	11 720
Goto, et al. [I9]	Gas evolution	14 300
ASA C57.92-1948	50% tensile strength retention	14 830 [a]
IEEE Std C57.92-1981	50% tensile strength retention	16 054
IEEE Std C57.91-1981	DT life tests	14 594

[a] 120 °C to 150 °C temperature range.

From Table I.1 it may seem that there is not a single "right" value of *B*, but it must be remembered that all experimental data is subject to variability and the materials and test conditions for all of the investigators were certainly not identical. Placing the most emphasis on the more modern data (Shroff and Stannet [I20], Goto, Tsukioka, and Mori [I9], Head, Gale, and Lawson [I10]), it seems that a value of *B* of 15 000 would be appropriate and is used in the transformer insulation life curve in this loading guide.

For small distribution transformers, it is possible to define an end point for insulation life by means of functional life tests on the actual apparatus, as was done in the 1960s. However, this is not economically practical for power transformers. Another option is to make the definition in terms of a measurable physical characteristic—mechanical, electrical, or chemical. It can involve a percentage retention of the characteristic or an absolute level of the characteristic that is judged to be essential for functionality. Dielectric strength is the characteristic that would relate most closely to functionality, but it has been found that it deteriorates very slowly if the insulation is not disturbed mechanically. Thus, a mechanical characteristic, usually tensile strength, has customarily been chosen~~,~~ with an end-point criterion of 50% retained tensile strength. However, this has a deficiency in that 50% retained strength for initially weak paper could be a lower absolute strength than 25% retained strength for initially strong paper.

Functional life test evaluations on power transformer models were sponsored by EPRI in the 1978 to 1982 time period (EPRI [I2], EPRI [I3], and McNutt and Kaufman [I16]). They demonstrated that the ANSI 50 %-retained tensile-strength life criterion is very conservative. In one program (EPRI [I2], McNutt and Kaufman [I16]), small disk coils were aged for 6.2 times ANSI life without failure on short circuit and dielectric end-point tests. The aged coils had suffered only a 10% reduction of the initial dielectric strength. In a separate program (EPRI [I3]), disk windings were aged for 8.6, 12.0, and 15.3 ANSI life (see IEEE Std C57.92-1981) without failure on short-circuit and dielectric end-point tests.

An alternative end-point criterion, an absolute level of DP, has the advantages that only a small sample is required, measurement is simple, and the results tend to have less dispersion than tensile strength measurements. Many investigators (Fabre and Pichon [I8], Head, Gale, and Lawson [I10], Lampe and Spicar [I12], Lawson, Simmons, and Gale [I14], Yoshida, et al. [I22~~]~~]) have shown good correlation between reduction of mechanical properties and reduction of DP. Using DP, an end-point criterion can be selected based on subjective judgment of "loss of useful mechanical properties." Various investigators Bozzini [I6], Fabre and Pichon [I8], Lampe, Spicar and Carranger [I13], Shroff and Stannet [I20], tend to choose different levels of DP for the endpoint, ranging from 100 to 250. A value of 200 seems a good compromise for power transformers, but smaller transformers subjected to lower mechanical stress levels in service could possibly accept a lower limit. Some small transformers have continued operation in service with DP below 100 (Bassetto and Mak [I4]).

Selection of an absolute value for useful life of transformer insulation at the reference temperature of 110 °C is very subjective. The general feeling at present is that the definition of 65 000 h given in IEEE Std C57.92-1981 (and earlier versions) may be excessively conservative. This value was chosen based on time to 50% tensile strength reduction of the insulation in sealed tube aging tests. The functional life tests on power transformer models previously mentioned confirmed that 65 000 was extremely conservative, perhaps by a factor of 2 or 3. At various times during the early deliberations about loading guides, lower levels of residual tensile strength were considered for the end point in sealed tube aging tests, down to a level of 20% residual (Sumner, Stein, and Lockie [I21]). At that level, the life could be considered to be 150 000 h and would be approximately equivalent to an end-point criterion of 200 residual DP. A slightly more conservative end point would be 25% residual tensile strength at a life of 135 000 h.

Functional life testing of distribution transformers was begun in 1957 (Acker [I1]) to evaluate the life of 55 °C average winding rise insulation in that product. A factor of safety of 5 was applied to the most pessimistic results to obtain a life definition for distribution transformers of 180 000 h at 95 °C. More recent tests by individual manufacturers on the 65 °C average winding rise insulation system distribution transformers have demonstrated a similar useful life at 110 °C. The normal life of 180 000 h has been used in this standard for many years.

Both the results of functional tests and service experience suggest that a normal life of 15–20 years at a winding hot spot temperature of 110 °C is a reasonable expectation for both distribution and power transformers with well-dried and oxygen-free insulation systems. A 20-year life has long standing in the loading guides for distribution transformers. When an absolute value is placed on time to reach a selected life end point, the effect of all of the significant variables must be considered, namely heat, water, and oxygen. Accelerated material aging tests that formed the basis for the traditional IEEE Std C57.92-1981 life curves (time to 50% retained tensile strength) were always carried out with very low moisture and oxygen contents in the aging cell. The same can be said for power transformer models and distribution transformers subjected to functional life tests. However, such is not always the case for in-service transformers, particularly those older units with open conservator oil preservation systems. An end of functional life criterion must, therefore, reflect not only a suitable end-point measurement level, but also appropriate moisture and oxygen levels in the insulation system of the operating transformer. For modern, well-sealed systems, these levels are comparable to those in the sealed cell material life evaluation tests.

The effect of the two controllable variables, water and oxygen, on aging rates has been extensively investigated. Fabre and Pichon [I8] stated a very simple rule for the effect of water, namely that the deterioration rate is directly proportional to the water content. Shroff's and Stannet's data [I20] supports that relationship. The reference moisture level typical for material aging tests is 0.2% to 0.3% by weight, so the deterioration rates must be proportionally increased for higher moisture levels in operating transformers. However, the moisture level at the critical location, the hottest spot, is typically only about half of the average moisture level, because of moisture partitioning by temperature. Fabre and Pichon [I8] also investigated the effect of oxygen, comparing deterioration rates for a sealed low oxygen content system to an open free-breathing system. He found a deterioration acceleration factor of 2.5 for the open system. In a similar study, Lampe et al. [I13] found a factor of 10. All of these data give utilities good incentive to employ an oil preservation system that maintains low moisture and oxygen levels in their transformers.

Water, heat, and oxygen are the catalyst, the accelerator, and the active reagent in the oxidation of the oil in oil-filled transformers. The products of oil oxidation are acids, esters, and metallic soaps that attack the cellulose insulation with vigor and tenacity. The oxidation by-products also attack the oil producing additional oxidation by-products. If failures of the oil preservation system occur (loss of tank seal), then oil oxidation that dramatically accelerates insulation deterioration can be expected.

To summarize, the effect of heat on the useful life of a cellulose insulation material can be estimated on a per unit basis without regard to end-of-life criteria or internal conditions in the insulation system using Equation (I.2). Cumulative loss-of-life can be calculated for varying load conditions on this relative basis (see Table I.3 and Table I.4), with the result that one real day of operation will produce less or more aging than one day at the reference temperature of 110 °C (for a 65 °C average winding rise insulation system).

During development of the 1995 revision of IEEE Std C57.91, after the working group agreed to combine the existing separate guides into one document, some users of power transformers were concerned about the effect of dropping the old life curve for power transformers and adopting the life curve for distribution transformers. Their concern was the effect on the calculations of the insulation loss of life. To alleviate those concerns, the Working Group developed a table of alternative end of life values that the user could choose from, when performing loss of insulation life calculations. The authors failed to adequately explain why the table was created. That table is now included in this annex to document the historical information.

Table I.2—Options offered in the 1995 revision of IEEE Std C57.91—Normal insulation life of a well-dried oxygen-free 65 °C average winding temperature rise system at the reference temperature of 110 °C

Basis	Normal insulation life	
	Hours	Years
50% retained tensile strength of insulation (former IEEE Std C57.92-1981 criterion)	65 000	7.42
25% retained tensile strength of insulation	135 000	15.41
200 retained degree of polymerization in insulation	150 000	17.12

Interpretation of distribution transformer functional life test data (former IEEE Std C57.91-1981 criterion)	180 000	20.55
NOTE 1— Tensile strength or degree of polymerization (D.P.) retention values were determined by sealed tube aging on well-dried insulation samples in oxygen-free oil. NOTE 2 — Per IEEE Std C57.12.00-2010 (5.11.3) a minimum normal insulation life of 180 000 h is required. Other end of life criteria have been used historically for developing transformer loading. They are provided above for reference.		

I.3 Example calculations

In the first example (see Table I.3) with a mild overload, the life consumption was about 107.7% of one day at reference temperature, while for the short-time emergency load in Table I.4, with hottest-spot temperature rising to 180 °C for a very brief time, the life consumption was about 18.6 times that of one day at reference temperature. It should be noted that in the development of Table I.3 and Table I.4 and in the sample calculation, the hot spot temperature that was used was that for the end of each hour, with the assumption made that the temperature was constant for the full hour. In reality, the hot-spot temperature will vary during any one hour of loading. If this variation is small, there is little error in the calculation of aging hours, but if the variation is larger, such as 5 ° C–10 °C, or more as around the hour 17:00 in Table I.4, the error can be significant. To minimize this error, it is recommended that a computer program be used in which the aging hours are calculated in small increments, such as every 3 min or 5 min.

One example of the use of the aging acceleration factor (FAA) would be for planned overloading. A 24 h variable load cycle would be input, which consists of variable loads and ambient temperature. The ambient and peak load might be high during the day and reduced during the night. Also an equivalent aging factor for a summer load cycle might be averaged with an equivalent aging factor for the winter. If the average was 1.0 for the year, then the kVA purchased was correct. If the average was above 1.0, then a higher kVA should be purchased. Or, economics might be factored in and the best return on the investment would be achieved by loading to, say, a 1.1 equivalent aging factor, which would accelerate slightly the use of the life of the unit and recover the investment more quickly. The user could then buy a newer transformer with more up-to-date technology if the old one failed due to this loading or other reasons.

In order to apply an absolute time scale to the life measurement, an appropriate end-of-life criterion must be selected. Tensile strength retention of 50% would be conservative and a lesser level could be accepted. Alternatively, an absolute level of DP, such as a value of 200, could be chosen as a level at which "useful mechanical properties" of the cellulose are still retained. In the Table I.4 example, the absolute percentage of total life lost in this 24 h period is given for the four "normal life" optional values for the user to choose from suggested in 9.1. In making this calculation, the aging acceleration effects of moisture and oxygen must be considered if these parameters are not maintained at low levels.

Table 1 of Clause 5 gives aging acceleration factors.

This annex is based largely on a condensation of material presented in McNutt [I15].

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA,n} \Delta t_n}{\sum_{n=1}^{N} \Delta t_n} = \frac{25.857}{24} = 1.077$$

where

F_{EQA} is equivalent aging factor for the total time period

$F_{AA,n}$ is aging acceleration factor for the temperature that exists during the time interval Δt_n

n is index of the time interval, Δt

N is total number of time intervals

Δt_n is time interval, h

This is equivalent to aging of 1.077 days or 25.848 hours at 110 °C.

$$\%\text{Loss of Life} = \frac{F_{EQA} \times 24 \times 100}{\text{Normal Insulation Life}} = \frac{1.077 \times 24 \times 100}{180{,}000} = 0.014\%$$

Based on normal insulation life of 180 000 h.

Table I.3—24 h load cycle aging calculation mild overload 100 MVA transformer (65 °C rise)

Time	Load (P.U. of N.P.)	Hot-spot temp. °C	Aging acel factor $F_{AA,n}$	Aging hours	Cumulative age hours
1:00	0.599	80.0	0.036	0.036	0.036
2:00	0.577	72.8	0.015	0.015	0.051
3:00	0.555	72.9	0.015	0.015	0.066
4:00	0.544	72.8	0.015	0.015	0.080
5:00	0.544	71.8	0.013	0.013	0.093
6:00	0.566	71.8	0.013	0.013	0.107
7:00	0.655	73.0	0.015	0.015	0.122
8:00	0.844	74.2	0.018	0.018	0.139
9:00	0.955	85.1	0.066	0.066	0.205
10:00	1.021	92.2	0.148	0.148	0.353
11:00	1.054	99.1	0.318	0.318	0.671
12:00	1.077	104.6	0.571	0.571	1.242
13:00	1.088	109.2	0.921	0.921	2.163
14:00	1.099	112.8	1.329	1.329	3.492
15:00	1.099	116.0	1.830	1.830	5.322
16:00	1.110	117.8	2.185	2.185	7.507
17:00	1.200	125.0	4.376	4.376	11.882
18:00	1.077	130.0	6.984	6.984	18.866
19:00	0.977	125.0	4.376	4.376	23.242
20:00	0.910	114.0	1.499	1.499	24.741
21:00	0.877	104.8	0.583	0.583	25.324
22:00	0.866	97.9	0.279	0.279	25.603
23:00	0.832	93.2	0.166	0.166	25.769
24:00	0.788	87.6	0.088	0.088	25.857

Table I.4—24 h load cycle aging calculation short time emergency
100 MVA transformer
(65 °C rise)

	Load	Hot-spot temp.	Aging acel factor $F_{AA,n}$		Cumulative
1:00	0.599	80.0	0.036	0.036	0.036
2:00	0.577	72.8	0.015	0.015	0.051
3:00	0.555	72.9	0.015	0.015	0.066
4:00	0.544	72.8	0.015	0.015	0.080
5:00	0.544	71.8	0.013	0.013	0.093
6:00	0.566	71.8	0.013	0.013	0.107
7:00	0.655	73.0	0.015	0.015	0.122
8:00	0.844	74.2	0.018	0.018	0.139
9:00	0.955	85.1	0.066	0.066	0.205
10:00	1.021	92.2	0.148	0.148	0.353
11:00	1.054	99.1	0.318	0.318	0.671
12:00	1.077	104.6	0.571	0.571	1.242
13:00	1.088	109.2	0.921	0.921	2.163
14:00	1.099	112.8	1.329	1.329	3.492
15:00	1.099	116.0	1.830	1.830	5.322
16:00	1.110	117.8	2.185	2.185	7.507
17:00	1.690	180.0	424.922	424.922	432.429
18:00	1.077	130.0	6.984	6.984	439.413
19:00	0.977	125.0	4.376	4.376	443.789
20:00	0.910	114.0	1.499	1.499	445.288
21:00	0.877	104.8	0.583	0.583	445.871
22:00	0.866	97.9	0.279	0.279	446.150
23:00	0.832	93.2	0.166	0.166	446.316
24:00	0.788	87.6	0.088	0.088	446.403

$$F_{EQA} = \frac{\sum_{n=1}^{N} F_{AA,n} \Delta t_n}{\sum_{n=1}^{N} \Delta t_n} = \frac{446.403}{24} = 18.6$$

$$\%\text{Loss of Life} = \frac{F_{EQA} \times 24 \times 100}{\text{Normal Insulation Life}} = \frac{18.6 \times 24 \times 100}{180{,}000} = 0.248\%$$

Using the normal life selections from Table I.2 gives the following:

a) 65 000 h = 0.687%
b) 135 000 h = 0.331%
c) 150 000 h = 0.298%
d) 180 000 h = 0.248%

I.4 Bibliography for Annex I

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Question:

11. Refer to Mr. Blumenstock's direct testimony, page 11, lines 1-6

  a. Provide a list of the Company's HVD substations.

  b. For each HVD substation, provide the following:

    i. Name
    ii. Location as geographically specific as can be included in public record
    iii. If jointly occupied, identity of co-occupant(s) other than Consumers Energy
    iv. High-side voltage
    v. Low-side voltage
    vi. Number of inbound (transmission) lines
    vii. Number of outbound (HVD) lines
    viii. kVA rating and number of transformers for each kVA rating used at the substation
    ix. Type of voltage regulation
    x. 8760-hour load profile for historical test year 2019
    xi. Projected year substation load (Consumers Energy side) will reach current station capacity
    xii. Projected year of significant rebuild due to equipment aging (Consumers Energy side)

Response:

All of the attachments to this discovery response are Confidential and contain critical energy infrastructure information (CEII). The Company provides these confidential attachments pursuant to the Protective Order in Case No. U-20963, and only to those persons who have signed the nondisclosure certificate pursuant to such Protective Order.

For subparts a through b.v, please see Confidential Attachment 1 to this discovery response. However, subpart b.iii requests information that contains sensitive customer or third-party information, and cannot be provided.

For subparts b.vi and b.vii, please see Confidential Attachment 2 to this discovery response.

For subpart b.viii, please see Confidential Attachment 3 to this discovery response, which also contains information responsive to discovery request 20963-MEC-CE-488.

For subpart b.ix, please see Confidential Attachment 4 to this discovery response. For substations labeled "No Consumers Energy Voltage Regulation," there either is no regulator at that site or it is a customer-owned substation and the Company does not have the information.

b.x. This information is not readily available. HVD substations have various components that each can have their own load profile, meaning there is no single substation load profile.

b.xi. The Company is not currently projecting any HVD substations to reach their capacity in the next 5 years. However, the HVD system models are updated annually to account for changes that happen on the system such as, new interconnections, new load additions, changes in projected load growth, and other changes. The models are used to continually evaluate HVD substation capacity and projects would be scheduled to mitigate any projected capacity problems.

b.xii. The company does not have a projected year of rebuild for every HVD Substation based on equipment aging. HVD Substations and the equipment in them are continually evaluated for reliability concerns, such as deterioration, condition, operability, capacity, aging/obsolete equipment, and other potential concerns that could affect the substation performance and reliability and are prioritized and scheduled for rebuild based on consideration of all factors mentioned. The Company has identified HVD substations for rebuild through 2023, as discussed on page 194, lines 13 through 19, of my direct testimony.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Electric Planning

Question:

13. Refer to Mr. Blumenstock's direct testimony, page 11, lines 14-20.

a. Provide a list of the Company's LVD substations.

b. For each LVD substation, provide the following:

i. Name
ii. Location as geographically specific as can be included in public record
iii. If jointly occupied, identity of co-occupant(s) other than Consumers Energy
iv. Identification whether the substation is for general distribution, dedicated to a customer, customer-owned, Consumers Energy owned providing wholesale distribution service to rural co-op and municipal systems, or customer-owned substation providing wholesale distribution service to rural co-op and municipal systems
v. High-side voltage
vi. Low-side voltage
vii. Number of inbound lines from the Consumers Energy HVD system
viii. Number of inbound lines from transmission
ix. Number of outbound (LVD) lines
x. kVA rating and number of transformers for each kVA rating used at the substation
xi. Type of voltage regulation
xii. Number of Consumers Energy customers served by the substation, by major class
xiii. 8760-hour load profile for historical test year 2019
xiv. 8760-hour load profile for historical test year 2019, by major customer class
xv. Projected year substation load will reach current station capacity
xvi. Projected year of significant rebuild due to equipment aging (Consumers Energy side)

Response:

All of the attachments to this discovery response are Confidential and contain critical energy infrastructure information (CEII). The Company provides these confidential attachments pursuant to the Protective Order in Case No. U-20963, and only to those persons who have signed the nondisclosure certificate pursuant to such Protective Order.

For subparts a, b.i, b.v, and b.vi, please see Confidential Attachment 1 to this discovery response.

For subpart b.ii, please see Confidential Attachment 2 to this discovery response.

The Company cannot provide the information requested in subpart b.iii, as it contains sensitive customer and third-party information.

For subpart b.iv, please see Confidential Attachment 3 to this discovery response. In this attachment, "Other" includes substations which are only used to interconnect generation, which serve a municipality or other electric utility, and/or which are not owned by the Company.

For subparts b.vii and b.viii, please refer to Confidential Attachment 4 to this discovery response.

For subpart b.ix, please refer to Confidential Attachment 5 to this discovery response.

For subpart b.x, please refer to Confidential Attachment 3 to discovery response 20963-MEC-CE-486.

For subpart b.xi, please refer to Confidential Attachment 6 to this discovery response.

For subpart b.xii, please refer to Confidential Attachment 5 to this discovery response. Please note that the number of customers served from a substation can change over time. The numbers provided in this response are current as of May 4, 2021. The Company does not have a customer class breakdown readily available for all substations.

b.xiii. This information is not readily available. LVD substations have various components that can each have their own load profile, meaning there is no single substation load profile.

b.xiv. See subpart b.xiii.

b.xv. The Company does not maintain a comprehensive list specifying the projected year that every substation will reach the current station capacity rating. Load projections utilized for project planning require individualized assumptions, analysis, and study to achieve quality results. Without detailed study, a projected overload year cannot be reasonably determined, and the effort needed to develop quality projections cannot be completed on every substation annually. LVD Substations Capacity projects are implemented when a component of the substation has experienced an overload, or when a component of the substation will experience an overload with the connection of a known load addition. Rather than maintaining a comprehensive list for all substations, the Company focuses primarily on the substations nearing projected capacity limitations.

b.xvi. The Company does not maintain a comprehensive list specifying the projected year that every substation would be rebuilt due to equipment aging, because equipment age is one of several components considered in the planning of a substation rebuild project. The Company does not rebuild substations based solely on age.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
May 6, 2021

Electric Planning

RAP®

Electric Cost Allocation for a New Era

A Manual

By Jim Lazar, Paul Chernick and William Marcus

Edited by Mark LeBel

JANUARY 2020

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Contents

Part III: Embedded Cost of Service Studies

11. Distribution in Embedded Cost of Service Studies

Distribution costs are all incurred to deliver energy to customers and are primarily investment-related costs that do not vary in response to load in the short term. Different rate analysts approach these costs in very different ways. These costs are often divided into two categories.

1. Shared distribution, which typically includes at least:
   - Distribution substations, both those that step power down from transmission voltages to distribution voltages and those that step it down from a higher distribution voltage (such as 25 kV) to a lower voltage (such as 12 kV).
   - Primary feeders, which run from the substations to other substations and to customer premises, including the conductors, supports (poles and underground conduit) and various control and monitoring equipment.
   - Most line transformers, which step the primary voltage down to secondary voltages (under 600 V, and mostly in the 120 V and 240 V ranges) for use by customers.
   - A large portion of the secondary distribution lines, which run from the line transformers to customer service lines or drops.
   - The supervisory control and data acquisition equipment that monitors the system operation and records system data. This is a network of sensors, communication devices, computers, software and typically a central control center.
2. Customer-specific costs, which include:
   - Service drops connecting a customer (or multiple customers in a building) to the common distribution system (a primary line, a line transformer or a secondary line or network).
   - Meters, which measure each customer's energy use by month, TOU period or hour and sometimes by maximum demand in the month.[135] Advanced meters can also provide other capabilities, including measurement of voltage, remote sensing of outages, and remote connection and disconnection.[136]
   - Street lighting and signal equipment, which usually can be directly assigned to the corresponding rate classes.
   - In some systems with low customer spatial density, a significant portion of primary lines and transformers serving only one customer.

11.1 Subfunctionalizing Distribution Costs

One important issue in cost allocation is the determination of the portion of distribution cost that is related to primary service (the costs of which are allocated to all customers, except those served at transmission voltage) as opposed to secondary service (the costs of which are borne solely by the secondary voltage customers — residential, some C&I customers, street lighting, etc.).

Some plant accounts and associated expenses are easily subfunctionalized. Substations (which are all primary equipment) have their own FERC accounts (plant accounts 360 to 362, expense accounts 582 and 592). In addition, distribution substations take power from transmission lines and feed it into the distribution system at primary voltage. All distribution substations deliver only primary power and therefore should be subfunctionalized as 100% primary.

135 The Uniform System of Accounts treats meters as distribution plant and the costs of keeping the meters operable as distribution expenses, even though all other metering and billing costs are treated as customer accounts or A&G plant or expenses. Traditional meters that tally only customer usage are not really necessary for the operation of the distribution system, only for the billing function. As a result, references to meters in this chapter are quite limited, and the costs of meters are discussed with meter reading and billing in the next chapter.

136 These capabilities require additional supporting technology, some of which is also required to provide remote meter reading. These costs should be spread among a variety of functions, including distribution and retail services, as discussed in Section 11.5.

However, many other types of distribution investments pose more difficult questions. The FERC accounts do not differentiate lines, poles or conduit between primary and secondary equipment, and many utilities do not keep records of distribution plant cost by voltage level. This means any subfunctionalization requires some sort of special analysis, such as the review of the cost makeup of distribution in areas constituting a representative sample of the system.

Traditionally, most cost of service studies have functionalized a portion of distribution poles as secondary plant, to be allocated only to classes taking service at secondary voltage. This approach is based on misconceptions regarding the joint and complementary nature of various types of poles. Although distribution poles come in all sorts of sizes and configurations, the important distinction for functionalization is what sorts of lines the poles carry: only primary, both primary and secondary or only secondary. The proper functionalization of the first category — poles that carry only primary lines — is not controversial; they are required for all distribution load, the sum of load served at primary and the load for which power is subsequently stepped down to secondary.[137]

For the second category — poles carrying both primary and secondary lines — some cost of service studies have treated a portion of the pole cost as being due to all distribution load and the remainder as being due to secondary loads, to be allocated only to classes served at secondary voltage. There is no cost basis for allocating any appreciable portion of these joint poles to secondary. The incremental pole cost for adding secondary lines to a pole carrying primary is generally negligible. The height of the pole is determined by the voltage of the primary circuits it carries, the number of primary phases and circuits and the local topography. Much of the equipment on the poles (cross arms, insulators, switches and other monitoring and control equipment) is used only for the primary lines. The required strength of the pole (determined by the diameter and material) is determined by the weight of the lines and equipment and by the leverage exerted by that weight (which increases with the height of the equipment and the breadth of the cross arms, again due to primary lines).[138] Equipment used in holding secondary lines has a very low cost compared with those used for primary lines. If the poles currently used for both secondary and primary lines had been designed without secondary lines, the reduction in costs would be very small. Thus, the costs of the joint poles are essentially all due to primary distribution.

Although nearly all poles carry primary lines, a utility sometimes will use a pole just to carry secondary lines, such as to reach from the last transformer on a street to the last house, or to carry a secondary line across a wide road to serve a few customers on the far side. Secondary-only poles are usually shorter and skinnier and thus less expensive than primary poles and do not require cross arms and other primary equipment. Some cost of service studies functionalize a portion of pole costs to secondary, based on the population of secondary-only poles (either from an actual inventory or an estimate) or of short poles (less than 35 feet, for example), on the theory that these short poles must carry secondary.

The assumption that all short poles carry secondary is not correct; some utility poles carry no conductor but rather are stubs used to counterbalance the stresses on heavily loaded (mostly primary) poles, as illustrated in Figure 39 on the next page. Depending on the nature of the distribution system and the utility's design standards, the number of stub poles may rival the number of secondary-only poles.

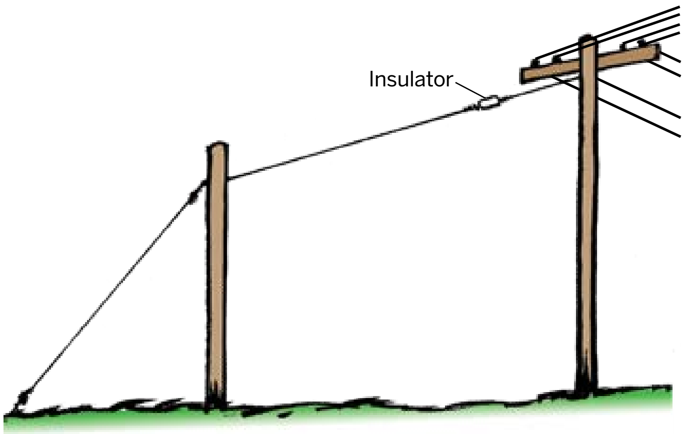
Where only secondary lines are needed, the utility typically saves on pole costs due to the customer taking secondary service, rather than requiring primary voltage service and a bigger pole. Some kind of pole would be needed in that location regardless of the voltage level of service. Hence, the primary customers are better off paying for their share of the secondary poles than if the customers using those poles were to require primary service. It does not seem fair to penalize customers served at secondary for the fact that the utility is able to serve some of them using a type of pole that is less expensive than the poles required for primary service.

As a result, the vast majority of pole costs (other than for

137 The class loads should be measured at primary voltage, including losses, which will be higher for power metered at secondary.

138 There is one situation in which secondary distribution can add to the cost of poles. A very large pole-mounted transformer (perhaps over 75 kVA) may require a stronger pole, which would be a secondary distribution cost. A highly detailed analysis of pole subfunctionalization might thus result in a portion of the cost of those few poles being treated as an extra cost of secondary service, offset to some extent by the savings from some poles being designed to carry only secondary lines.

Figure 39. Stub pole used to guy a primary pole



dedicated poles directly assigned to street lighting or similar services) generally should be treated as serving all distribution customers.[139] For many cost of service studies, that would result in the costs being subfunctionalized as primary distribution, which is then allocated to classes in proportion to their contribution to demand at the primary voltage level.

Line transformers dominate two FERC accounts (plant account 368 and expense account 595), but those accounts also include the costs of capacitors and voltage regulators. These three types of equipment should be subfunctionalized in three different manners:

- Secondary line transformers (which compose the bulk of these accounts) are needed only for customers served at secondary voltage and thus can be subfunctionalized as 100% secondary.
- Voltage regulators are devices on the primary system that adjust voltage levels along the feeder to keep delivered voltage within the design range. The number and capacity of voltage regulators is determined by the distribution of load along the feeder, regardless of whether that load is served at primary or secondary. The regulator costs should be subfunctionalized as primary distribution and classified in the same manner as substations and primary conductors.
- Capacitors improve the power factor on distribution lines at primary voltage, thus reducing line losses (reducing generation, transmission and distribution costs), reducing voltage drop (avoiding the need for larger and additional primary conductors) and increasing primary distribution line capacity. Capacitors can be functionalized as some mix of generation, transmission and primary distribution; in any case they should be functionalized separately from line transformers.

Overhead and underground conductors as well as conduit must be subfunctionalized between primary and secondary using special studies of the composition of the utility's distribution system, since secondary conductors are mostly incremental to primary lines. Estimates of the percentage of these investments that are secondary equipment typically range from 20% to 40%.

Within the primary conductor category, utilities use three-phase feeders for areas with high loads and single-phase (or occasionally two-phase) feeders in areas with lower loads. The additional phases (and hence additional conductors) are due to load levels and the use of equipment that specifically requires three-phase supply (such as some large motors), which is one reason that primary distribution is overwhelmingly load-related and should be so treated in classification.

Some utilities subfunctionalize single- and three-phase conductors, treating the single-phase lines as incremental to the three-phase lines (see, for example, Peppin, 2013, pp. 25-26). Classes that use a lot of single-phase lines are allocated both the average cost of the three-phase lines and the average cost of the single-phase lines. This treatment of single-phase service as being more expensive than three-phase service gets it backward. If load of a single-phase customer or area changed in a manner that required three-phase service, the utility's costs would increase; if anything, classes disproportionally served with single-phase primary should be assigned lower costs than those requiring three-phase service. The classification of primary conductor as load-related will allocate more of the three-phase costs to the classes whose loads require that equipment.

139 As noted above, some utilities may be able to attribute some upgrades in pole class to line transformers; that increment is appropriately functionalized to secondary service. On the other hand, the secondary classes may be due a small credit to reflect the fact that they allow the use of some less expensive poles.

11.2 Distribution Classification

The classification of distribution infrastructure has been one of the most controversial elements of utility cost allocation for more than a half-century. Bonbright devoted an entire section to a discussion of why none of the methods then commonly used was defensible (1961, pp. 347-368). In any case, traditional methods have divided up distribution costs as either demand-related or customer-related, but newly evolving methods can fairly allocate a substantial portion of these costs on an energy basis.

Newly evolving methods can fairly allocate a substantial portion of distribution costs on an energy basis.

Distribution equipment can be usefully divided into three groups:

- Shared distribution plant, in which each item serves multiple customers, including substations and almost all spans of primary lines.
- Customer-related distribution plant that serves only one customer, particularly traditional meters used solely for billing.
- A group of equipment that may serve one customer in some cases or many customers in others, including transformers, secondary lines and service drops.

The basic customer method for classification counts only customer-specific plant as customer-related and the entire shared distribution network as demand- or energy-related. For relatively dense service territories, in cities and suburbs, this would be only the traditional meter and a portion of service drop costs.[140] For very thinly settled territories, particularly rural cooperatives, customer-specific plant may include some portion of transformer costs and the percentage of the primary system that consists of line extensions to individual customers. Many jurisdictions have mandated or accepted the basic customer classification approach, sometimes including a portion of transformers in the customer cost. These jurisdictions include Arkansas,[141] California,[142] Colorado,[143] Illinois,[144] Iowa,[145] Massachusetts,[146] Texas[147] and Washington.[148]

The basic customer method for classification is by far the most equitable solution for the vast majority of utilities.

140 Alternatively, all service drops may be treated as customer-related and the sharing of service drops can be reflected in the allocation factor. As discussed in Section 5.2, treating multifamily housing as a separate class facilitates crediting those customers with the savings from shared service drops, among other factors.

141 The Arkansas Public Service Commission found that "accounts 364-368 should be allocated to the customer classes using a 100% demand methodology and … that [large industrial consumer parties] do not provide sufficient evidence to warrant a determination that these accounts reflect a customer component necessary for allocation purposes" (2013, p. 126).

142 California classifies all lines (accounts 364 through 367) as demand-related for the calculation of marginal costs, while classifying transformers (Account 368) as customer-related with different costs per customer for each customer class, reflecting the demands of the various classes.

143 In 2018, the state utility commission affirmed a decision by an administrative law judge that rejected the **zero-intercept approach** and classified FERC accounts 364 through 368 as 100% demand-related (Colorado Public Utilities Commission, 2018, p. 16).

144 "As it has in the past, … the [Illinois Commerce] Commission rejects the minimum distribution or zero-intercept approach for purposes of allocating distribution costs between the customer and demand functions in this case. In our view, the coincident peak method is consistent with the fact that distribution systems are designed primarily to serve electric demand. The Commission believes that attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic" (Illinois Commerce Commission, 2008, p. 208).

145 According to 199 Iowa Administrative Code 20.10(2)e, "customer cost component estimates or allocations shall include only costs of the distribution system from and including transformers, meters and associated customer service expenses." This means that all of accounts 364 through 367 are demand-related. Under this provision, the Iowa Utilities Board classifies the cost of 10 kVA per transformer as customer-related but reduces the cost that is assigned to residential and small commercial customers to reflect the sharing of transformers by multiple customers.

146 "Plant items classified as customer costs included only meters, a portion of services, street lighting plant, and a portion of labor-related general plant" (La Capra, 1992, p. 15). See also Gorman, 2018, pp. 13-15.

147 Texas has explicitly adopted the basic customer approach for the purposes of rate design: "Specifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service" (Public Utility Commission of Texas, 2000, pp. 5-6). But it has followed this rule in practice for cost allocation as well.

148 "The Commission finds that the Basic Customer method represents a reasonable approach. This method should be used to analyze distribution costs, regardless of the presence or absence of a decoupling mechanism. We agree with Commission Staff that proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals" (Washington Utilities and Transportation Commission, 1993, p. 11).

For certain rural utilities, this may be reasonable under the conceptual view that the size of distribution components (e.g., the diameter of conductors or the capacity of transformers) is load-related, but the number and length of some types of equipment is customer-related. In some rural service territories, the basic customer cost may require nearly a mile of distribution line along the public way as essentially an extended service drop.

However, more general attempts by utilities to include a far greater portion of shared distribution system costs as customer-related are frequently unfair and wholly unjustified. These methods include straight fixed/variable approaches where all distribution costs are treated as customer-related (analogous to the misuse of the concept of fixed costs in classifying generation discussed in Section 9.1) and the more nuanced minimum system and zero-intercept approaches included in the 1992 NARUC cost allocation manual.

The minimum system method attempts to calculate the cost (in constant dollars) if the utility's installed units (transformers, poles, feet of conductors, etc.) were each the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks: How much would it have cost to install the same number of units (poles, feet of conductors, transformers) but with the size of the units installed limited to the current minimum unit normally installed? This minimum system cost is then designated as customer-related, and the remaining system cost is designated as demand-related. The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related.

This minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related. Specifically, it is unrealistic to suppose that the mileage of the shared distribution system and the number of physical units are customer-related and that only the size of the components is demand-related, for at least eight reasons.

1. Much of the cost of a distribution system is required to cover an area and is not sensitive to either load or customer number. The distribution system is built to cover an area because the total load that the utility expects to serve will justify the expansion into that area. Serving many customers in one multifamily building is no more expensive than serving one commercial customer of the same size, other than metering. The shared distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers along a circuit of equivalent length and hence does not vary with customer number.[149] Bonbright found that there is "a very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by the system." He concluded that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems … clearly indefensible. [Cost analysts are] under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground" (1961, p. 348).
2. The minimum system approach erroneously assumes that the minimum system would consist of the same number of units (e.g., number of poles, feet of conductors) as the actual system. In reality, load levels help determine the number of units as well as their size. Utilities build an additional feeder along the route of an existing feeder (or even on the same poles); loop a second feeder to the end of an existing line to pick up some load from the existing line; build an additional feeder in parallel with an existing feeder to pick up the load of some of its branches; and upgrade feeders from single-phase to three-phase. As secondary load grows, the utility typically will add transformers, splitting smaller customers among the existing and new transformers.[150] Some other feeder construction is designed to improve reliability (e.g., to interconnect feeders with automatic switching to reduce the number of customers affected by outages and outage duration).

149 As noted above, for some rural utilities, particularly cooperatives that extend distribution without requiring that the extension be profitable, a portion of the distribution system may effectively be customer-specific.

150 Adding transformers also reduces the length of the secondary lines from the transformers to the customers, reducing losses, voltage drop or the required gauge of the secondary lines.

3. Load can determine the type of equipment installed as well. When load increases, electric distribution systems are often relocated from overhead to underground (which is more expensive) because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, requiring early replacement of some equipment with more expensive equipment (e.g., new transformers, increased insulation, higher poles to accommodate higher voltage or additional circuits). Thus, a portion of the extra costs of moving equipment underground or of newer equipment may be driven in part by load.
4. The "minimum system" would still meet a large portion of the average residential customer's demand requirements. Using a minimum system approach requires reducing the demand measure for each class or otherwise crediting the classes with many customers for the load-carrying capability of the minimum system (Sterzinger, 1981, pp. 30-32).
5. Minimum system analyses tend to use the current minimum-sized unit typically installed, not the minimum size ever installed or available. The current minimum unit is sized to carry expected demand for a large percentage of customers or situations. As demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less expensive small equipment because rising demand results in very rare use of the small equipment and the cost of maintaining stock is no longer warranted.[151] However, the transformer industry could produce truly minimum-sized utility transformers, the size of those used for cellular telephone chargers, if there were a demand for these.
6. Adding customers without adding peak demand or serving new areas does not require any additional poles or conductors. For example, dividing an existing home into two dwelling units increases the customer count but likely adds nothing in utility investment other than a second meter. Converting an office building from one large tenant to a dozen small offices similarly increases customer number without increasing shared distribution costs. And the shared distribution investment on a block with four large customers is essentially the same as for a block with 20 small customers with the same load characteristics. If an additional service is added into an existing street with electrical service, there is usually no need to add poles, and it would not be reasonable to assume any pole savings if the number of customers had been half the actual number.
7. Most utilities limit the investment they will make for low projected sales levels, as we also discuss in Section 15.2, where we address the relationship between the utility line extension policy and the utility cost allocation methodology. The prospect of adding revenues from a few commercial customers may induce the utility to spend much more on extending the distribution system than it would invest for dozens of residential customers.
8. Not all of the distribution system is embedded in rates, since some customers pay for the extension of the system with **contributions in aid of construction**, as discussed in Section 15.2. Factoring in the entire length of the system, including the part paid for with these contributions, overstates the customer component of ratepayer-funded lines.

Thus, the frequent assumption that the number of feet of conductors and the number of secondary service lines is related to customer number is unrealistic. A piece of equipment (e.g., conductor, pole, service drop or meter) should be considered customer-related only if the removal of one customer eliminates the need for the unit. The number of meters and, in most cases, service drops is customer-related, while feet of conductors and number of poles are almost entirely load-related. Reducing the number of customers, without reducing area load, will only rarely affect the length of lines or the number of poles or transformers. For example, removing one customer will avoid

151 For example, in many cases, utilities that make an allocation based on a minimum system use 10-kVA transformers, even though they installed 3-kVA or 5-kVA transformers in the past. Some utilities also have used conductor sizes and costs significantly higher than the actual minimum conductor size and cost on their systems.

overhead distribution equipment only under several unusual circumstances.[152] These circumstances represent a very small part of the shared distribution cost for the typical urban or suburban utility, particularly since many of the most remote customers for these utilities might be charged a contribution in aid of construction. These circumstances may be more prevalent for rural utilities, principally cooperatives.

The related zero-intercept method attempts to extrapolate from the cost of actual equipment (including actual minimum-sized equipment) to the cost of hypothetical equipment that carries zero load. The zero-intercept method usually involves statistical regression analysis to decompose the costs of distribution equipment into customer-related costs and costs that vary with load or size of the equipment, although some utilities use labor installation costs with no equipment. The idea is that this procedure identifies the amount of equipment required to connect existing customers that is not load-related (a zero-kVA transformer, a zero-**ampere** conductor or a pole that is zero feet high). The zero-intercept regression analysis is so abstract that it can produce a wide range of results, which vary depending on arcane statistical methods and the choice of types of equipment to include or exclude from an equation. As a result, the zero-intercept method is even less realistic than the minimum system method.

The best practice is to determine customer-related costs using the basic customer method, then use more advanced techniques to split the remainder of shared distribution system costs as energy-related and demand-related. Energy use, especially in high-load hours and in off-peak hours on high-load days, affects distribution investment and outage costs in the following ways:

- The fundamental reason for building distribution systems is to deliver energy to customers, not simply to connect them to the grid.
- The number and extent of overloads determines the life of the insulation on lines and in transformers (in both substations and line transformers) and hence the life of the equipment. A transformer that is very heavily loaded for a couple of hours a year and lightly loaded in other hours may last 40 years or more until the enclosure rusts away. A similar transformer subjected to the same annual peaks, but also to many smaller overloads in each year, may burn out in 20 years.
- All energy in high-load hours, and even all hours on high-load days, adds to heat buildup and results in sagging overhead lines, which often defines the thermal limit on lines; aging of insulation in underground lines and transformers; and a reduction the ability of lines and transformers to survive brief load spikes on the same day.
- Line losses depend on load in every hour (marginal line losses due to another kWh of load greatly exceed the average loss percentage in that hour, and losses at peak loads dramatically exceed average losses).[153] To the extent that a utility converts a distribution line from single-phase to three-phase, selects a larger conductor or increases primary voltage to reduce losses, the costs are primarily energy-related.
- Customers with a remote need for power only a few hours per year, such as construction sites or temporary businesses like Christmas tree lots, will often find non-utility solutions to be more economical. But when those same types of loads are located along existing distribution lines, they typically connect to utility service if the utility's **connection charges** are reasonable.

A portion of distribution costs can thus be classified to energy, or the demand allocation factor can be modified to reflect energy effects.

The average-and-peak method, discussed in Section 9.1 in the context of generation classification, is commonly used by natural gas utilities to classify distribution mains and other shared distribution plant.[154] This approach recognizes that a portion of shared distribution would be needed even if all

152 These circumstances are: (1) if the customer would have been the farthest one from the transformer along a span of secondary conductor that is not a service drop; (2) if the customer is the only one served off the last pole at the end of a radial primary feeder, a pole and a span of secondary, or a span of primary and a transformer; and (3) if several poles are required solely for that customer.

153 For a detailed analysis of the measurement and valuation of marginal line losses, see Lazar and Baldwin (2011).

154 See *Gas Distribution Rate Design Manual* from the National Association of Regulatory Utility Commissioners (1989, pp. 27-28) as well as more recent orders from the Minnesota Public Utilities Commission describing the range of states that use basic customer and average-and-peak methods for natural gas cost allocation (2016, pp. 53-54) and the Michigan Public Service Commission affirming the usage of the average-and-peak method (2017, pp. 113-114).

customers used power at a 100% load factor, while other costs are incurred to upsize the system to meet local peak demands. The same approach may have a place in electric distribution system classification and allocation, with something over half the basic infrastructure (poles, conductors, conduit and transformers) classified to energy to reflect the importance of energy use in justifying system coverage and the remainder to demand to reflect the higher cost of sizing equipment to serve a load that isn't uniform.

Nearly every electric utility has a line extension policy that dictates the circumstances under which the utility or a new customer must pay for an extension of service. Most of these provide only a very small investment by the utility in shared facilities such as circuits, if expected customer usage is very small, but much larger utility investment for large added load. Various utilities compute the allowance for line extensions in different ways, which are usually a variant of one of the following approaches:

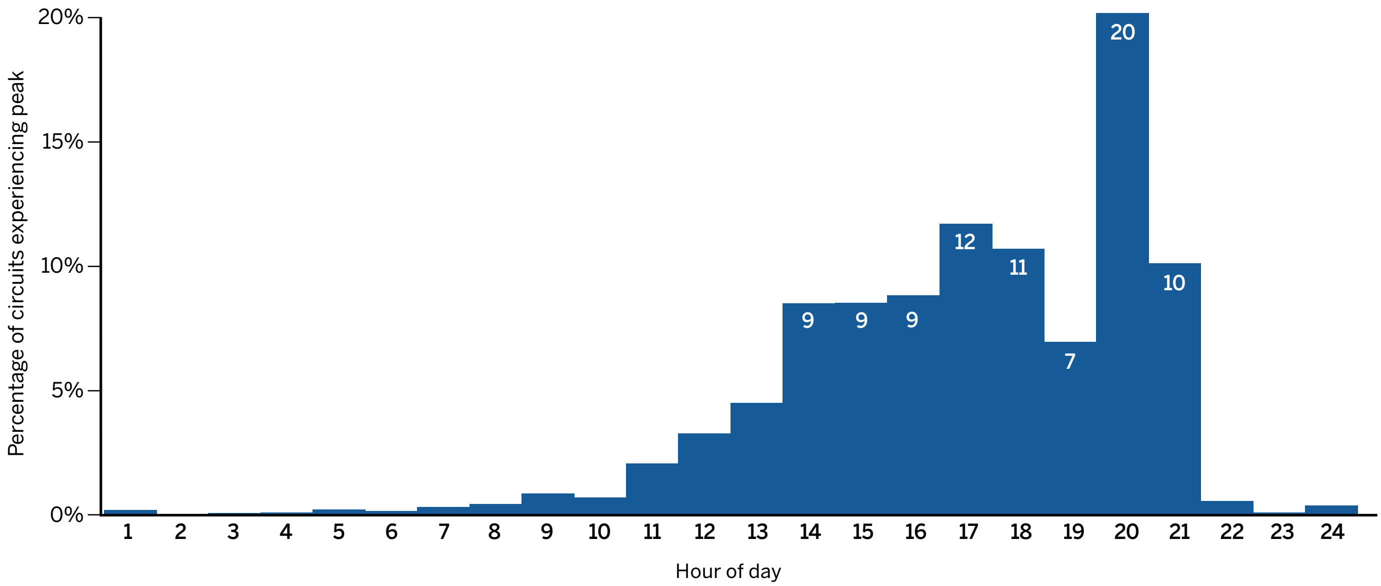
- The credit equals a multiple of revenue. For example, Otter Tail Power Co. in Minnesota will invest up to three times the expected annual revenue, with the customer bearing any excess (Otter Tail Power Co., 2017, Section 5.04). Xcel Energy's Minnesota subsidiary uses 3.5 times expected annual revenue for nonresidential customers (Northern States Power Co.-Minnesota, 2010, Sheet 6-23). Other utilities base their credits on expected nonfuel revenue or the distribution portion of the tariff; on different periods of revenue; and on either simple total revenue or present value of revenue.[155] These are clearly usage-related allowances that, in turn, determine how much cost for distribution circuits is reflected in the utility revenue requirement. Applying this logic, all shared distribution plant should thus be classified as usage-related, and none of the shared distribution system should be customer-related.
- The credit is the actual extension cost, capped at a fixed value. For example, Minnesota Power pays up to $850 for the cost of extending lines, charges $12 per foot for costs over $850 and charges actual costs for extensions over 1,000 feet (Minnesota Power, 2013, p. 6). Xcel Energy's Colorado subsidiary gives on-site construction allowances of $1,659 for residential customers, $2,486 for small commercial, $735 per kW for other secondary nonresidential and $680 per kW for primary customers (Public Service Company of Colorado, 2018, Sheet R226). The company describes these allowances as "based on two and three-quarters (2.75) times estimated annual non-fuel revenue" — a simplified version of the revenue approach.[156]
- The credit is determined by distance. Xcel Energy's Minnesota subsidiary includes the first 100 feet of line extension for a residential customer into rate base, with the customer bearing the cost for any excess length (Northern States Power Co.-Minnesota, 2010, Sheet 6-23). Green Mountain Power applies a credit equal to the cost of 100 feet of overhead service drop but no costs for poles or other equipment (Green Mountain Power, 2016, Sheet 148). The portion of the line extensions paid by the utility might be thought of as customer-related, with some caveats. First, the amount of the distribution system that was built out under this provision is almost certainly much less than 100 feet times the number of residential customers. Second, these allowances are often determined as a function of expected revenue, as in the Xcel Colorado example, and thus are usage-related.

If the line extension investment is tied to revenue (and most revenue is associated with usage-related costs, such as fuel, purchased power, generation, transmission and substations), then the resulting investment should be classified and allocated on a usage basis. The cost of service study should ensure that the costs customers prepay are netted out (including not just the costs but the footage of lines or excess costs of poles and transformers if a minimum system method is used) before classifying any distribution costs as customer-related.

155 California sets electric line extension allowances at expected net distribution revenue divided by a cost of service factor of roughly 16% (California Public Utilities Commission, 2007, pp. 8-9).

156 The company also has the option of applying the 2.75 multiple directly (Public Service Company of Colorado, 2018, Sheet R212).

Figure 40. San Diego Gas & Electric circuit peaks



Source: Fang, C. (2017, January 20). Direct testimony on behalf of San Diego Gas & Electric. California Public Utilities Commission Application No. 17-01-020

11.3 Distribution Demand Allocators

In any traditional study, a significant portion of distribution plant is classified as demand-related. A newer hourly allocation method may omit this step, assigning distribution costs to all hours when the asset (or a portion of the cost of the asset) is required for service.

For demand-related costs, class NCP is commonly, but often inappropriately, used for allocation. This allocator would be appropriate if each component overwhelmingly served a single class, if the equipment peaks occurred roughly at the time of the class peak, and if the sizing of distribution equipment were due solely to load in a single hour. But to the contrary, most substations and many feeders serve several tariffs, in different classes, and many tariff codes.[157]

11.3.1 Primary Distribution Allocators

Customers in a single class, in different areas and served by different substations and feeders, may experience peak loads at different times. Figure 40 shows the hours when each of San Diego Gas & Electric's distribution circuits experienced peak loads (Fang, 2017, p. 21). The peaks are clustered between the early afternoon (on circuits that are mostly commercial) and the early evening (mostly residential), while other circuits experience their peaks at a wide variety of hours.

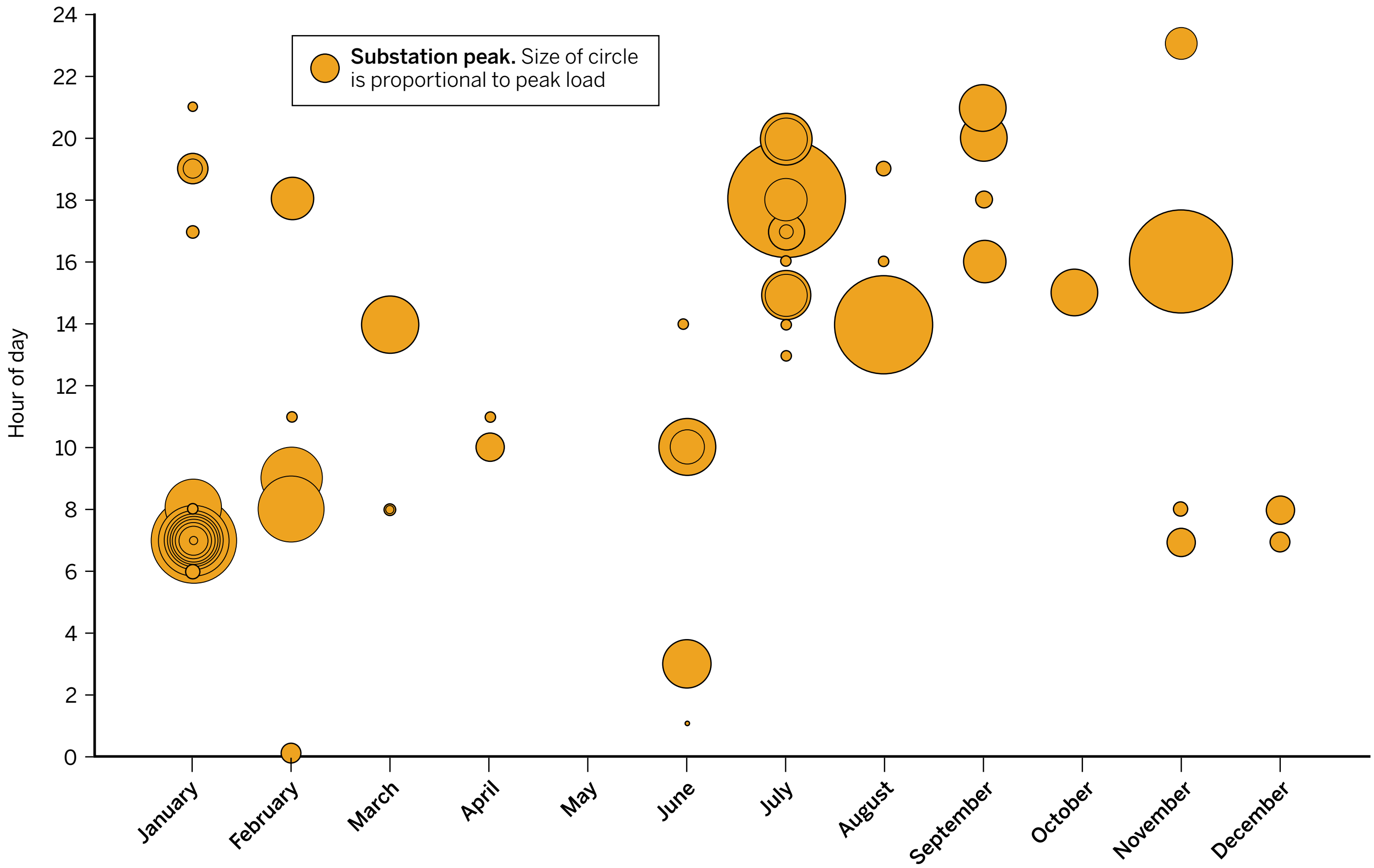
Figure 41 on the next page shows the distribution of substation peaks for Delmarva Power & Light over a period of one year (Delmarva Power & Light, 2016). The area of each bubble is proportional to the peak load on the station. Clearly, no one peak hour (or even a combination of monthly peaks) is representative of the class contribution to substation peaks.

The peaks for substations, lines and other distribution equipment do not necessarily align with the class NCPs. Indeed, even if all the major classes are summer peaking, some of the substations and feeders may be winter peaking, and vice versa. Even within a season, substation and feeder peaks will be distributed to many hours and days.

Although load levels drive distribution costs, the maximum load on each piece of equipment is not the only important load. As explained in Subsection 5.1.3, increased

157 Some utilities design their substations so that each feeder is fed by a single transformer, rather than all the feeders being served by all the transformers at the substation. In those cases, the relevant loads (for timing and class mix) are at the transformer level, rather than the entire substation.

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

energy use, especially at high-load hours and prior to those hours, can also affect the sizing and service life of transformers and underground lines, which is thus driven by the energy use on the equipment in high-load periods, not just the maximum demand hour. The peak hourly capacity of a line or transformer depends on how hot the equipment is prior to the peak load, which depends in turn on the load factor in the days leading up to the peak and how many high-load hours occur prior to the peak. More frequent events of load approaching the equipment capacity, longer peaks and hotter equipment going into the peak period all contribute to faster insulation deterioration and cumulative line sag, increasing the probability of failure and accelerating aging.

Ideally, the allocators for each distribution plant type should reflect the contribution of each class to the hours when load on the substation, feeder or transformer contributes to the potential for overloads. That allocation could be constructed by assigning costs to hours or by constructing a special demand allocator for each category of distribution equipment. If a detailed allocation is too complex, the allocators for costs should still reflect the underlying reality that distribution costs are driven by load in many hours.

The resulting allocator should reflect the variety of seasons and times at which the load on this type of equipment experiences peaks. In addition, the allocator should reflect the near-peak and prepeak loads that contribute to overheating and aging of equipment. Selecting the important hours for distribution loads and the weight to be given to the prepeak loads may require some judgments. Class NCP allocators do not serve this function.

Rocky Mountain Power allocates primary distribution on monthly coincident distribution peak, weighted by the percentage of substations peaking in each month (Steward, 2014, p. 7). Under this weighting scheme, for example:

- A small substation has as much effect on a month's weighting factor as a large substation. The month with the largest number of large substations seriously overloaded could be the highest-cost month yet may not receive the highest weight since each substation is weighted equally.
- The month's contribution to distribution demand costs is assumed to occur entirely at the hour of the monthly distribution peak, even though most of the substation capacity that peaks in the month may have peaked in a variety of different hours.
- A month would receive a weight of 100% whether each substation's maximum load was only 1 kVA more than its maximum in every other month or four times its maximum in every other month.

This approach could be improved by reflecting the capacity of the substations, the actual timing of the peak hours and the number of near-peak hours of each substation in each month. The hourly loads might be weighted by the square or some other power of load or by using a peak capacity allocation factor for the substation, to reflect the fact that the contribution to line losses and equipment life falls rapidly as load falls below peak.

Many utilities will need to develop additional information on system loads for cost allocation, as well as for planning, operational and rate design purposes. Specifically, utilities should aim to understand when each feeder and substation reaches its maximum loads and the mix of rate classes on each feeder and distribution substation.

In the absence of detailed data on the loads on line transformers, feeders and substations, utilities will be limited to cruder aggregate load data. For primary equipment, the best available proxy may be the class energy usage in the expected high-load period for the equipment, the class contribution to coincident peak or possibly class NCP, but only if that NCP is computed with respect to the peak load of the customers sharing the equipment. Although most substations and feeders serving industrial and commercial customers will also serve some residential customers, and most residential substations and feeders will have some commercial load, some percentage of distribution facilities serve a single class.

The NCP approximation is not a reasonable approximation for finer disaggregation of class loads. For example, there are many residential areas that contain a mix of single-family and multifamily housing and homes with and without electric space heating, electric water heating and solar panels. The primary distribution plant in those areas must be sized for the combined load in coincident peak periods, which may be the late afternoon summer cooling peak, the evening winter heating and lighting peak or some other time — but it will be the same time for all the customers in the area.[158]

Many utilities have multiple tariffs or tariff codes for residential customers (e.g., heating, water heating, all-electric and solar; single-family, multifamily and public housing; low-income and standard), for commercial customers (small, medium and large; primary and secondary voltage; schools, dormitories, churches and other customer types) and for various types of industrial customers, in addition to street lighting and other services. In most cases, those subclasses will be mixed together, resulting in customers with gas and electric space heat, gas and electric water heat, and with and without solar in the same block, along with street lights. The substation and feeder will be sized for the combined load, not for the combined peak load of just the electric heat customers or the combined peak of the customers with solar panels[159] or the street lighting peak.

Unless there is strong geographical differentiation of the subclasses, any NCP allocator should be computed for the

158 Distribution conductors and transformers have greater capacity in winter (when heat is removed quickly) than in summer; even if winter peak loads are higher, the sizing of some facilities may be driven by summer loads.

159 The division of the residential class into subclasses for calculation of the class NCP has been an issue in several recent Texas cases. In Docket No. 43695, at the recommendation of the Office of Public Utility Counsel, the Public Utility Commission of Texas reversed its former method for Southwestern Public Service to use the NCP for a single residential class (instead of separate subclasses for residential customers with and without electric heat), which reduced the costs allocated to residential customers as a whole (Public Utility Commission of Texas, 2015, pp. 12-13 and findings of fact 277A, 277B and 339A). The issue was also raised in dockets 44941 and 46831 involving El Paso Electric Co. El Paso Electric proposed separate NCP allocations for residential customers with and without solar generation, which the Office of Public Utility Counsel and solar generator representatives opposed. Both of these cases were settled and did not create a precedent.

combined load of the customer classes, with the customer class NCP assigned to rate tariffs in proportion to their estimated contribution to the customer class peak.

11.3.2 Relationship Between Line Losses and Conductor Capacity

In some situations, conductor size is determined by the economics of line losses rather than by thermal overloads or voltage drop. Even at load levels that do not threaten reliability, larger conductors may cost-effectively reduce line losses, especially in new construction.[160] The incremental cost of larger capacity can be entirely justified by loss reduction (which is mostly an energy-related benefit), with higher load-carrying capability as a free additional benefit.

11.3.3 Secondary Distribution Allocators

Each piece of secondary distribution equipment generally serves a smaller number of customers than a single piece of primary distribution equipment. On a radial system, a line transformer may serve a single customer (a large commercial customer or an isolated rural residence) or 100 apartments; a secondary line may serve a few customers or a dozen, depending on the density of load and construction. Older urban neighborhoods often have secondary lines that are connected to several transformers, and some older large cities such as Baltimore have full secondary networks in city centers.[161] In contrast, a primary distribution feeder may serve thousands of customers, and a substation can serve several feeders.

Thus, loads on secondary equipment are less diversified than loads on primary equipment. Hence, cost of service studies frequently allocate secondary equipment on load measures that reflect customer loads diversified for the number of customers on each component. Utilities often use assumed diversity factors to determine the capacity required for secondary lines and transformers, for various numbers of customers. Figure 42 on the next page provides an example of the diversity curve from El Paso Electric Co. (2015, p. 24).

Even identical houses with identical equipment may routinely peak at different times, depending on household composition, work and school schedules and building orientation. The actual peak load for any particular house may occur not at typical peak conditions but because of events not correlated with loads in other houses. For example, one house may experience its maximum load when the family returns from vacation to a hot house in the summer or a very cold one in the winter, even if neither temperatures nor time of day would otherwise be consistent with an annual maximum load. The house next door may experience its maximum load after a water leak or interior painting, when the windows are open and fans, dehumidifiers and the heating or cooling system are all in use.

Accounting for diversity among different types of residential customers, the load coincidence factors would be even lower. A single transformer may serve some homes with electric heat, peaking in the winter, and some with fossil fuel heat, peaking in the summer.

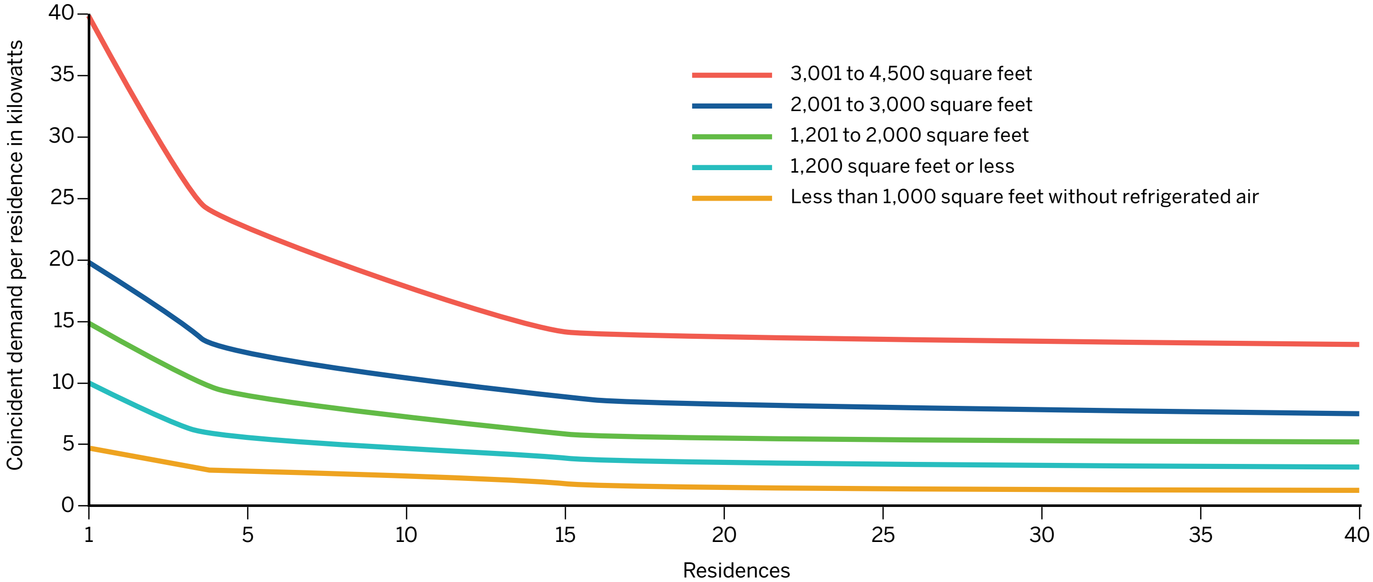
The average transformer serving residential customers may serve a dozen customers, depending on the density of the service territory and the average customer NCP, which for the example in Figure 42 suggests that the customers' average contribution to the transformer peak load would be about 40% of the customers' undiversified load. Thus, the residential allocator for transformer demand would be the class NCP times 40%. Larger commercial customers generally have very little diversity at the transformer level, since each transformer (or bank of transformers) typically serves only one or a few customers.

The same factors (household composition, work and

160 The same is true for increased distribution voltage. Seattle City Light upgraded its residential distribution system from 4 kV to 26 kV in the early 1980s based on analysis done in the Energy 1990 study, prepared in 1976, which focused on avoiding new baseload generation. The line losses justified the expenditure, but the result was also a dramatic increase in distribution system circuit capacity. The Energy 1990 study was discussed in detail in a meeting of the City Council Utilities Committee (Seattle Municipal Archives, 1977).

161 In high-load areas, such as city centers, utilities often operate secondary distribution networks, in which multiple primary feeders serve multiple transformers, which then feed a network of interconnected secondary lines that feed all the customers on the network (See Behnke et al., 2005, p. 11, Figure 8). In secondary networks, the number of transformers and the investment in secondary lines are driven by the aggregate load of the entire network or large parts of the network. The loss of any one feeder and one transformer, or any one run of secondary line, will not disconnect any customer. The existence of the network, the number of transformers and the number and length of primary and secondary lines are entirely load-related. Similar arrangements, called spot networks, are used to serve individual large customers with high reliability requirements. A single spot network customer may thus have multiple transformers, providing redundant capacity.

Figure 42. Typical utility estimates of diversity in residential loads



Source: El Paso Electric Co. (2015, October 29). *El Paso Electric Company's Response to Office of Public Utility Counsel's Fifth Request for Information.* Public Utility Commission of Texas Docket No. 44941

school schedules, unit-specific events) apply in multifamily housing as well as in single-family housing. But the effects of orientation are probably even stronger in multifamily housing than in single-family homes. For example, units on the east side of a building are likely to have summer peak loads in the morning, while those on the west side are likely to experience maximum loads in the evening and those on the south in the middle of the day.

Importantly, Figure 42 represents the diversity of similar neighboring single-family houses. Diversity is likely to be still higher for other applications, such as different types and vintages of neighboring homes, or the great variety of customers who may be served from the shared transformers and lines of a secondary network.

Until 2001, the major U.S. electric utilities were required to provide the number and capacity of transformers in service on their FERC Form 1 reports. Assuming an average of one transformer per commercial and industrial customer, these reports typically suggest a ratio ranging from 3 to more than 20 residential customers per transformer, with the lower ratios for the most rural IOUs and the highest for utilities with dense urban service territories and many multifamily consumers.[162] Only about a dozen electric co-ops filed a FERC Form 1 with the transformer data in 2001, and their ratios vary from about 1 transformer per residential customer for a few very rural co-ops to about 8 residential customers per transformer for Chugach Electric, which serves part of Anchorage as well as rural areas.

Utilities can often provide detailed current data from their geographic information systems. Table 30 on the next page shows Puget Sound Energy's summary of the number of transformers serving a single residential customer and the number serving multiple customers (Levin, 2017, pp. 8-9). More than 95% of customers are served by shared transformers, and those transformers serve an average of 5.3 customers. Using the method described in the previous paragraph, an estimated average of 4.9 Puget Sound Energy residential customers would share a transformer, which is close to the actual average of 4.5 customers per transformer shown in Table 30 (Levin, 2017, and additional calculations by the authors).

The customers who have their own transformer may be too far from their neighbors to share a transformer, or local load growth may have required that the utility add a transformer. In many cases, residential customers with

162 Ratios computed using Form 1, p. 429, transformer data (Federal Energy Regulatory Commission, n.d.) and 2001 numbers from utilities' federal Form 861 (U.S. Energy Information Administration, n.d.-a, file 2).

Table 30. Residential shared transformer example

	With multiple residences per transformer	With single residence per transformer	Total
Number of transformers	197,503	47,699	245,202
Number of customers	1,054,296	47,699	1,101,995
Customers per transformer	5.3	1	4.5

Sources: Levin, A. (2017, June 30). Prefiled response testimony on behalf of NW Energy Coalition, Renewable Northwest and Natural Resources Defense Council. Washington Utilities and Transportation Commission Docket No. UE-170033; additional calculations by the authors

individual transformers may need to pay to obtain service that is more expensive than their line extension allowances (see Section 11.2 or Section 15.2).

Small customers will have similar, but lower, diversity on secondary conductors, which generally serve multiple customers but not as many as a transformer. A transformer that serves a dozen customers may serve two of them directly without secondary lines, four customers from one stretch of secondary line and six from another stretch of secondary line running in the opposite direction or across the street.

Where no detailed data are available on the number of customers per transformer in each class, a reasonable approximation might be to allocate transformer demand costs on a simple average of class NCP and customer NCP for residential and small commercial customers and just customer NCP for larger nonresidential customers.

11.3.4 Distribution Operations and Maintenance Allocators

Distribution O&M accounts associated with a single type of equipment (FERC accounts 582, 591 and 592 for substations and Account 595 for transformers) should be classified and allocated in the same manner as associated equipment. Other accounts serve both primary and secondary lines and service drops (accounts 583, 584, 593 and 594) or include services to a range of equipment (accounts 580 and 590). These costs normally should be classified and allocated in proportion to the plant in service, for the plant accounts they support, subfunctionalized as appropriate. For example, typical utility tree-trimming activities are almost entirely related to primary overhead lines, with very little cost driven by secondary distribution and no costs for protecting service lines (see, for example, Entergy Corp., n.d.).

11.3.5 Multifamily Housing and Distribution Allocation

One common error in distribution cost allocation is treating the residential class as if all customers were in single-family structures, with one service drop per customer and a relatively small number of customers on each transformer.[163] For multifamily customers, one or a few transformers may serve 100 or more customers through a single service line.[164] Treating multifamily customers as if they were single-family customers would overstate their contribution to distribution costs, particularly line transformers and secondary service lines.[165]

This problem can be resolved in either of two ways. The broadest solution is to separate residential customers into two allocation classes: single-family residential and multifamily residential, as we discuss in Section 5.2.[166] Alternatively, the allocation of transformer and service costs to a combined residential class (as well as residential rate design) should take into account the percentage of customers who are in multifamily buildings, and only components that are not shared should be considered customer-related.

163 One large service drop is much less expensive than the multiple drops needed to serve the same number of customers in single-customer buildings. Small commercial customers may also share service drops, although probably to a more limited extent than residential customers.

164 Similarly, if the cost of service study includes any classification of shared distribution plant as customer-related (such as from a minimum system), each multifamily building should be treated as a single location, rather than a large number of dispersed customers. For utilities without remote meter reading, the labor cost for that activity per multifamily customer will be lower than for single-family customers.

165 Allocating transformer costs on demand eliminates the bias for that cost category.

166 If any sort of NCP allocator is used in the cost of service study, the multifamily class load generally should be combined with the load of the type of customers that tend to surround the multifamily buildings in the particular service territory, which may be single-family residential or medium commercial customers.

11.3.6 Direct Assignment of Distribution Plant

Direct cost assignment may be appropriate for equipment required for particular customers, not shared with other classes, and not double-counted in class allocation of common costs. Examples include distribution-style poles that support streetlights and are not used by any other class; the same may be true for spans of conductor to those poles. Short tap lines from a main primary voltage line to serve a single primary voltage customer's premises may be another example, as they are analogous to a secondary distribution service drop.

Beyond some limited situations, it is not practical or useful to determine which distribution equipment (such as lines and poles) was built for only one class or currently serves only one class and to ensure that the class is properly credited for not using the other distribution equipment jointly used by other classes in those locations.

11.4 Allocation Factors for Service Drops

The cost of a service drop clearly varies with a number of factors that vary by class: customer load (which affects the capacity of the service line), the distance from the distribution line to the customer, underground versus overhead service, the number of customers sharing a service (or the number of services required by a single customer) and whether customers require three-phase service.

Some utilities, including Baltimore Gas & Electric, attempt to track service line costs by class over time (Chernick, 2010, p. 7). This approach is ideal but complicated. Although assigning the costs of new and replacement service lines just requires careful cost accounting, determining the costs of services that are retired and tracking changes in the class or classes in a building (which may change over time from manufacturing to office space to mixed residential and retail) is much more complex. Other utilities allocate service lines on the sum of customer maximum demands in each class. This has the advantage of reflecting the fact that larger customers require larger (and often longer) service lines, without requiring a detailed analysis of the specific lines in use for each class.

Many utilities have performed bottom-up analyses, selecting a typical customer or an arguably representative sample of customers in each class, pricing out those customers' service lines and extrapolating to the class. Since the costs are estimated in today's dollars, the result of these studies is the ratio of each class's cost of services to the total cost, or a set of weights for service costs per customer. Either approach should reflect the sharing of services in multifamily buildings.

11.5 Classification and Allocation for Advanced Metering and Smart Grid Costs

Traditional meters are often discussed as part of the distribution system but are primarily used for billing purposes.[167] These meters typically record energy and, for some classes, customer NCP demand for periodic manual or remote reading and generally are classified as customer-related. Meter costs are then typically allocated on a basis that reflects the higher costs of meters for customers who take power at higher voltage or three phases, for demand-recording meters, for TOU meters and for hourly-recording energy meters. The weights may be developed from the current costs of installing the various types of meters, but as technology changes, those costs may not be representative of the costs of equipment in rates.

In many parts of the country, this traditional metering has been replaced with advanced metering infrastructure. AMI investments were funded in many cases by the American Recovery and Reinvestment Act of 2009, the economic stimulus passed during the Great Recession, but in other cases ratepayers are paying for them in full in the traditional method. In many jurisdictions, AMI has been accompanied by other complementary "smart grid"

167 Some customers who are small or have extremely consistent load patterns are not metered; instead, their bills are estimated based on known load parameters. The largest group of these customers is street lighting customers, but some utilities allow unmetered loads for various small loads that can be easily estimated or nearly flat loads with very high load factors (such as traffic signals). An example of an unmetered customer from the past was a phone booth. Unmetered customers should not be allocated costs of traditional metering and meter reading.

Table 31. Smart grid cost classification

	Legacy approach			
Smart grid element	Equivalent cost	FERC account	Classification	Smart grid classification
Smart meters	Meters	370	Customer	Demand, energy and customer
Distribution control devices	Station equipment and devices	362, 365, 367	Demand	Demand and energy
Data collection system	Meter readers	902	Customer	Demand, energy and customer
Meter data management system	Customer accounting and general plant	903, 905, 391	Customer and overhead	Demand, energy and customer

investments. On the whole, these investments include:

- Smart meters, which are usually defined to include the ability to record and remotely report granular load data, measure voltage and power factor, and allow for remote connection and disconnection of the customer.
- Distribution system improvements, such as equipment to remotely monitor power flow on feeders and substations, open and close switches and breakers and otherwise control the distribution system.
- Voltage control equipment on substations to allow modulation of input voltage in response to measured voltage at the end of each feeder.
- Power factor control equipment to respond to signals from the meters.
- Data collection networks for the meters and line monitors.
- Advanced data processing hardware and software to handle the additional flood of data.
- Supporting overhead costs to make the new system work.

The potential benefits of the smart grid, depending on how it is designed and used, include reduced costs for generation, transmission, distribution and customer service, as described in Subsection 7.1.1. A smart meter is much more than a device to measure customer usage to assure an accurate bill — it is the foundation of a system that may provide some or all of the following:

- Benefits at every level of system capacity, by enabling peak load management since the communication system can be used to control compatible end uses, and because customer response to calls for load reduction can be measured and rewarded.
- Distribution line loss savings from improved power factor and phase balancing.
- Reduced energy costs due to load shifting.
- Reliability benefits, saving time and money on service restoration after outages, since the utility can determine which meters do not have power and can determine whether a customer's loss of service is due to a problem inside the premises or on the distribution system.
- Allowing utilities to determine maximum loads on individual transformers.
- Retail service benefits, by reducing meter reading costs compared with manual meter reads and even automated meter reading and by reducing the cost of disconnecting and reconnecting customers.[168]

The installations have also been very expensive, running into the hundreds of millions of dollars for some utilities, and the cost-effectiveness of the AMI projects has been a matter of dispute in many jurisdictions. Since these new systems are much more expensive than the older metering systems and are largely justified by services other than billing, their costs must be allocated over a wider range of activities, either by functionalizing part of the costs to generation, distribution and so on or reflecting those functions in classification or the allocation factor.

Special attention must be given to matching costs and benefits associated with smart grid deployment. The expected benefits spread across the entire spectrum of utility costs, from lower labor costs for meter reading to lower energy

168 The data systems can also be configured to provide systemwide Wi-Fi internet access, although they usually are not. See Burbank Water and Power (n.d.).

Table 32. Summary of distribution allocation approaches

Element	Method	Comments	Hourly allocation
Substations	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy ALLOCATOR: Loads on substations in hours at or near peaks	Reflect effect of energy near peak and preceding peak on sizing and aging	Allocate by substation cost or capacity, then to hours that stress that substation with peak and heating
Poles	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	Pole costs driven by revenue expectation	As primary lines
Primary conductors	FUNCTIONALIZATION: Entirely primary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	• Distribution network is installed due to revenue potential • Sizing determined by loads in and near peak hours	• Cost associated with revenue-driven line extension to all hours • Cost associated with peak loads and overloads on distribution of line peaks and high-load hours
Line transformers	FUNCTIONALIZATION: Entirely secondary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Secondary energy DEMAND ALLOCATOR: Diversified secondary loads in peak and near-peak hours	Reflect diversity	Distribution of transformer peaks and high-load hours
Secondary conductors	FUNCTIONALIZATION: Entirely secondary CLASSIFICATION: Demand and energy* ENERGY ALLOCATOR: Energy or revenue DEMAND ALLOCATOR: Loads in hours at or near peaks	Energy is more important for underground than overhead	Distribution of line peaks and high-load hours
Meters	FUNCTIONALIZATION: Advanced metering infrastructure to generation, transmission and distribution, as well as metering ALLOCATOR FOR CUSTOMER-RELATED COSTS: Weighted customer	Allocation of generation, transmission and distribution components depends on use of advanced metering infrastructure	N/A

* Except some to customer, where a significant portion of plant serves only one customer

costs due to load shifting and line loss reduction. Legacy methods for allocating metering costs as primarily customer-related would place the vast majority of these costs onto the residential rate class, but many of the benefits are typically shared across all rate classes. In other words, the legacy method would give commercial and industrial rate classes substantial benefits but none of the costs.

Table 31 identifies some of the key elements of smart grid cost and how these would be appropriately treated in an embedded cost of service study. These approaches match smart grid cost savings to the enabling expenditures.

11.6 Summary of Distribution Classification and Allocation Methods and Illustrative Examples

The preceding discussion identifies a variety of methods used to functionalize, classify and allocate distribution plant. Table 32 summarizes the application of some of those methods, including the hourly allocations that may be applicable for modern distribution systems with:

- A mix of centralized and distributed resources, conventional and renewable, as well as storage.
- The ability to measure hourly usage on the substations and feeders.
- The ability to estimate hourly load patterns on transformers and secondary lines.

Table 33. Illustrative allocation of distribution substation costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Class NCP: substation (legacy)	$9,730,000	$9,730,000	$7,297,000	$3,243,000	$30,000,000
Average and peak	$10,056,000	$10,056,000	$8,100,000	$1,788,000	$30,000,000
Hourly	$9,939,000	$10,533,000	$9,009,000	$519,000	$30,000,000

Note: Numbers may not add up to total because of rounding.

Where the available data or analytical resources will not support more sophisticated analyses of distribution cost causation, the following simple rules of thumb may be helpful.

- The only costs that should be classified as customer-related are those specific to individual customers:
  - Basic metering costs, not including the additional costs of advanced meters incurred for system benefits.
  - Service lines, adjusting for shared services in buildings with multiple tenants.
  - For very rural systems, where most transformers and large stretches of primary line serve only a single customer (and those costs are not recovered from contributions in aid of construction), a portion of transformer and primary costs.
- Other costs should be classified as a mix of energy and demand, such as using the average-and-peak allocator.
- The peak demand allocation factor should reflect the distribution of hours in which various portions of distribution system equipment experience peak or heavy loads. If the utility has data only on the time of substation peaks, the load-weighted peaks can be used to distribute the demand-related distribution costs to hours and hence to classes.

11.6.1 Illustrative Methods and Results

The following discussion and tables show illustrative methods and results for several of the key distribution accounts, focused only on the capital costs. The same principles should be applied to O&M costs and depreciation expense. These examples use inputs from tables 5, 6, 7 and 27.

Substations

Table 33 shows three methods for allocating costs of distribution substations. The first of these is a legacy method, relying solely on the class NCP at the substation level.[169] The second is an average-and-peak method, a weighted average between class NCP and energy usage. The third uses the hourly composite allocator, which includes higher costs for hours in which substations are highly loaded.

Primary Circuits

Distribution circuits are built where there is an expectation of significant electricity usage and must be sized to meet peak demands, including the peak hour and other high-load hours that contribute to heating of the relevant elements of the system. Table 34 on the next page illustrates the effect of four alternative methods. The first, based on the class NCP at the circuit level, again produces unreasonable results for the street lighting class. The second, the legacy minimum system method, is not recommended, as discussed above. The third and fourth use a simple (average-and-peak) and more sophisticated (hourly) approach to assigning costs based on how much each class uses the lines and how that usage correlates with high-load hours.

Transformers

Line transformers are needed to serve all secondary voltage customers, typically all residential, small general

169 The street lighting class NCP occurs in the night, and street lighting is a small portion of load on any substation, so the street lighting class NCP load rarely contributes to the sizing of summer-peaking substations. The NCP method treats off-peak class loads as being as important as those that are on-peak. This is particularly inequitable for street lighting, which is nearly always a load caused by the presence of other customers who collectively justify the construction of a circuit.

Table 34. Illustrative allocation of primary distribution circuit costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Class NCP: circuit (legacy)	$69,565,000	$69,565,000	$43,478,000	$17,391,000	$200,000,000
Minimum system (legacy)	$113,783,000	$51,783,000	$24,739,000	$9,696,000	$200,000,000
Average and peak	$67,041,000	$67,041,000	$53,997,000	$11,921,000	$200,000,000
Hourly	$66,258,000	$70,221,000	$60,059,000	$3,462,000	$200,000,000

Note: Numbers may not add up to total because of rounding.

service and street lighting customers and often other customer classes as well. We present four methods in Table 35: two archaic and two more reflective of dynamic systems and more granular data. All of these apportion no cost to the primary voltage class, which does not use distribution transformers supplied by the utility.

The first method is to apportion transformers in proportion to the class sum of customer noncoincident peaks. This method is not recommended because it fails to recognize that there is great diversity between customers at the transformer level; as noted in Subsection 11.3.3, each transformer in an urban or suburban system may serve anywhere from five to more than 50 customers. The second is the minimum system method, also not recommended because it fails to recognize the drivers of circuit construction, as discussed in Section 11.2. The third is the weighted transformers allocation factor we derive in Section 5.3 (Table 7), weighting the number of transformers by class at 20% and the class sum of customer NCP (recognizing that the diversity is not perfect) at 80%. The last is an hourly energy method but excluding the primary voltage class of customers.

Customer-Related Costs

The final illustration shows two techniques for the apportionment of customer-related costs, based on a traditional customer count and a weighted customer count. Even for simple meters used solely for billing purposes, larger customers require different and more expensive meters. There are fewer of them per customer class, but the billing system programming costs do not vary by number of customers. In addition, a weighted customer account is also relevant to customer service, discussed in the next chapter, because the larger use customers typically have access to superior customer service through “key accounts” specialists who are trained for their needs.

Table 35. Illustrative allocation of distribution line transformer costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Customer NCP (legacy)	$32,258,000	$16,129,000	$0	$1,613,000	$50,000,000
Minimum system (legacy)	$32,461,000	$14,773,000	$0	$2,766,000	$50,000,000
Weighted transformers factor	$29,806,000	$14,903,000	$0	$5,290,000	$50,000,000
Hourly	$23,810,000	$23,810,000	$0	$2,381,000	$50,000,000

Note: Numbers may not add up to total because of rounding.

Table 36. Illustrative allocation of customer-related costs by different methods

	Residential	Secondary commercial	Primary industrial	Street lighting	Total
Unweighted					
Customer count	100,000	20,000	2,000	50,000	172,000
Customer factor	58%	12%	1%	29%	100%
Customer costs	$58,140,000	$11,628,000	$1,163,000	$29,070,000	$100,000,000
Weighted					
Weighting factor	1	3	20	0.05	
Customer count	100,000	60,000	40,000	2,500	202,500
Customer factor	49%	30%	20%	1%	100%
Customer costs	$49,383,000	$29,630,000	$19,753,000	$1,235,000	$100,000,000

Note: Numbers may not add up to total because of rounding.

Table 36 first shows a traditional calculation based on the actual number of customers. Then it shows an illustrative customer weighting and a simple allocation of customer-related costs based on that weighting. Each street light is treated as a tiny fraction of one customer; although there are tens of thousands of individual lights, the bills typically include hundreds or thousands of individual lights, billed to a city, homeowners association or other responsible party.[170]

170 In some locales, street lighting is treated as a franchise obligation of the utility and is not billed. In this situation, there are no customer service or billing and collection expenses.

Question:

31. Please provide in either Excel or comma-separated-value format the 8760-hour anonymized load profiles for historical test year 2019, as follows:

a. 200 randomly selected customers who are currently in rate schedule RSP, are not enrolled in AC Cycling, Peak Time Rewards, Critical Peak Pricing, Senior Citizen, Los Income Credit or Income Assistance provisions, did not have behind the meter generation in 2019, and were customers throughout 2019. For each customer in this sample, identify whether they reside in an apartment building with 5 or more units.

b. 200 randomly selected customers who are currently in rate schedule RSP, are not enrolled in AC Cycling, Peak Time Rewards, or Critical Peak Pricing, did not have behind the meter generation in 2019, but are enrolled in the Senior Citizen provision, and were customers throughout 2019. For each customer in this sample, identify whether they reside in an apartment building with 5 or more units.

c. 200 randomly selected customers who are currently in rate schedule RSP, are not enrolled in AC Cycling, Peak Time Rewards, or Critical Peak Pricing, did not have behind the meter generation in 2019, but are enrolled in the RIA provision, and were customers throughout 2019. For each customer in this sample, identify whether they reside in an apartment building with 5 or more units.

d. 200 randomly selected customers who are currently in rate schedule RSP, are not enrolled in AC Cycling, Peak Time Rewards, or Critical Peak Pricing, did not have behind the meter generation in 2019, but are enrolled in the LIAC provision, and were customers throughout 2019. For each customer in this sample, identify whether they reside in an apartment building with 5 or more units.

e. 200 randomly selected customers who are currently in rate schedule RSP and reside in an apartment building with 5 or more units, are not enrolled in AC Cycling, Peak Time Rewards, Critical Peak Pricing, did not have behind the meter generation in 2019, and were customers throughout 2019. For each customer, identify whether the customer is currently in provision RSC, RIA, or LIAC.

f. 200 randomly selected customers who are currently in any residential rate, who were customers throughout 2019, and had behind-the-meter solar installed throughout 2019. For each of these customers provide the AC and DC ratings of their solar system in 2019 and the hourly inflow and hourly outflow for each hour, ensuring by identification or data format that all solar system sizing data, inflow and outflow data can be associated by customer. For each customer in this sample, identify whether they reside in an apartment building with 5 or more units.

g. 200 randomly selected customers who are currently in rate schedule RSH, are not enrolled in AC Cycling, Peak Time Rewards, or Critical Peak Pricing, and were customers throughout 2019. For each customer in this sample, identify whether they reside in an apartment building with 5 or more units.

h. 200 randomly selected customers who are currently in rate schedule RPM, are not enrolled in AC Cycling, Peak Time Rewards, or Critical Peak Pricing and were customers throughout 2019. For each customer in this sample, identify whether they reside in an apartment building with 5 or more units.

<u>Response:</u>

Please see the Company's response to each subpart below. Note that the Company does not track whether a customer resides in an apartment building with 5 or more units.

For the Attachments provided, please note the following:

- Unit of Measure: KWh
- Time Intervals: Time provided in EST. INT01 captures 00:00:00 - 00:59:59. Intervals are not cumulative. If an interval is missing, the energy is not captured in the following period.
- The identifier is a unique 9-letter code that's consistent for each customer across files. This code is used to protect customer privacy.

a. Please see Attachment 1
b. Please see Attachment 2
c. Please see Attachment 3
d. Please see Attachment 4
e. As noted above, the Company does not have the information requested.
f. Please see Attachment 5 for Inflow and Attachment 6 for outflow. Please see Attachment 7 for the AC and DC Rating (kW)
g. Please see Attachment 8
h. There are currently no customers on Rate RPM. Rate RPM will be available for customers on June 1, 2021.

Emily Davis

Emily A. Davis
April 28, 2021

Rates and Regulation

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	U-20963 ALJ Sharon Feldman

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-10** were served on the following:

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The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for MEC, NRDC, SC, and CUB

Date: June 22, 2021

By: Karla L Gerds Digitally signed by Karla Gerds Date: 2021.06.22 15:11:13 -04'00' ____________________

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