The Impact of Climate Change on Future ComEd Electricity Demand and Costs: New Evidence from Advanced Metering Infrastructure Data

Working paper, submitted for review

Abstract

Using anonymous electricity usage data captured by Advanced Metering Infrastructure (AMI), this first-of-its-kind analysis shows that by 2050 higher cooling needs in warmer summers will lead customers of Illinois' largest electric utility to use 3.9 TWh more electricity—with a 1.3 GW increase in peak usage—than in the base case scenario. Cumulatively, under conservative price projections, customers would pay an additional $10.9 billion (in 2018 dollars) over this period, with an annual increase of $517 million in the final year, amounting to 4.5% higher electricity costs for all customer classes. Climate change will hit residential electric bills hardest: the average cost increase for residential customers would be 7.7%, compared to 3% for the non-residential class.

Keywords

Climate change, Electricity, Electric utility, Advanced Metering Infrastructure, Consumer costs, Electricity demand, Weather, Electricity costs, Electric bills

1.0 Introduction

Although we have already begun to see climate change affecting spheres of economic activity, energy modelers rarely incorporate changing weather into future electricity demand models.[1] Forecasts solely based on econometrics using variables such as income, price and population but assuming no change in weather patterns are imprecise in an era of climate change.

Using newly-available interval usage data for individual residential customers in the ComEd service territory, the Citizens Utility Board (CUB) conducted a first-of-its-kind, forward-looking study designed to isolate the effect of anticipated temperature and humidity increases on energy consumption in northern Illinois households, while holding other weather variables constant. The analysis finds that electricity costs will increase significantly because of rising temperatures, even in the temperate American Midwest, and under conservative assumptions about future cost factors. It is clear from the data that addressing climate change has consumer benefits and that effective climate change mitigation strategies should be a priority for least-cost energy planning.

2.0 Overview

To forecast residential usage, CUB developed a degree-day model that correlates historical local weather data with anonymous electricity usage data captured by Advanced Metering Infrastructure (AMI), or "Smart Meters." We employed this model to estimate average daily residential usage through the end of 2050. Our projection of annual temperature increases was

[1]Intergovernmental Panel on Climate Change, *Climate Change 2014.*

Abbreviations: AEO, Annual Energy Outlook; AMI, Advanced Metering Infrastructure; API, Application Programming Interface; BRA, Base Residual Auction; CDD, Cooling Degree Days; CUB, Citizens Utility Board; EIA, Energy Information Administration; ELD, Enthalpy Latent Days; HDD, Heating Degree Days; ICC, Illinois Commerce Commission; LSE, Load-Serving Entity; RCP, Representative Concentration Pathway; PLC, Peak Load Contribution.

based on RCP 8.5 (Representative Concentration Pathway 8.5 detailed by the International Panel on Climate Change), while holding other weather variables constant.[2] We then extrapolated these results to project consumption of non-residential customers, based on the respective load proportions used for heating and cooling by each class. Comprised of the hourly usage data per month of between 358,428 and 726,136[3] individual customers from 2016 to 2018, this dataset allows the most accurate estimate of the relationship between temperature and electricity usage of any such study to date.

Under temperatures corresponding to the RCP 8.5 emissions trajectory, consumers in the ComEd service territory would briefly use less electricity on an annual basis, as milder winters require less energy for home heating. However, higher cooling needs in warmer summers would immediately increase peak demand and quickly overtake non-summer consumption savings, leading to increases in overall annual usage by 2023. By 2050, we estimate ComEd-area customers will use 3.9 TWh more electricity—with a 1.3 GW increase in peak usage—than in the base case scenario due to rising temperatures. These represent 4.3% and 5.7% increases, respectively. Cumulatively, under conservative price projections,[4] customers would pay an additional $10.9 billion (in 2018 dollars) over this period, with an annual increase of $517 million in the final year, amounting to 4.5% higher electricity costs for all customer classes. Proportionally, this increase would be larger for residential customers than non-residential

[2] Intergovernmental Panel on Climate Change, "Data Distribution Centre."
[3] The number of customers increases every month, as ComEd did not complete full AMI deployment until 2019.
[4] Price projections were taken from U.S. Energy Information Administration, *Annual Energy Outlook 2019*.

customers: the 2050 cost increase for residential customers would be 7.7%, compared to 3% for the non-residential class.[5]

These cost increases are based only on projected higher electricity usage associated with rising temperatures and do not take into account additional factors, such as the likely need to build expensive transmission lines or upgrade the distribution system to meet increased levels of demand.[6] Other climate-related factors are also likely to drive up electricity usage, lending urgency to the need for policies and programs designed to optimize efficient use of the electric system and to reduce costs.

3.0 Theory

Our analysis calculated climate-induced electricity costs by first correlating historical weather with granular consumption data, then using that relationship to project future hourly household usage based on the annual temperature increases predicted by the RCP 8.5 emissions scenario. We then estimated annual consumer electricity costs by applying energy, distribution, and capacity cost forecasts from the U.S. Energy Information Administration's (EIA) latest Annual Energy Outlook (AEO).[7]

Historically, researchers have used two methods of correlating local weather to energy usage: degree-day modeling and multivariate regression analysis. While multivariate regression models can provide accurate short-term projections, degree-day modeling produces higher accuracy in long-term projections. For this reason, we used the degree-days approach for our analysis.

[5] This result is consistent with Mukherjee and Nateghi, "A data-driven approach", 673-694, which finds that the residential sector is more sensitive to climate variability than the commercial and industrial sectors.
[6] These costs are likely to be substantial. Research in Boehlert et al., "Climate change impacts and costs." estimates infrastructure expenditures may rise as much as 25% due to climate change alone.
[7] U.S. Energy Information Administration, *Annual Energy Outlook 2019*.

Degree-day modeling measures the acuteness of summer and winter conditions.[8] Beginning in the 1990s, several studies examined the sensitivity to degree day variables of natural gas and electricity consumption in the U.S. residential and commercial sectors.[9,10,11] Lee and Levermore used a degree-days model to estimate impacts of weather on energy consumption and demand in two South Korean cities and found that an increase in cooling degree days (CDDs) would lead to a considerable rise in energy consumption and demand.[12] A similar result was found for Guangzhou, China by Zheng, Huang, Zhou, and Zhu.[13] Bach pointed to heating and cooling degree days as good predictors of climate-driven energy loads.[14] From the available literature, we can conclude that degree days and energy consumption are highly correlated.[15]

4.0 Methodology

4.1 Data

The two main data sets used for this analysis are AMI usage data and historical local weather data. The details of the selection and cleaning of both data sets are explained in the following sections.

4.1.1 AMI Data

In 2017, the Illinois Commerce Commission (ICC) approved a plan for Illinois electric utilities to make granular smart meter data of individual residential customers available to researchers

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[8] Day, *Degree Days: Theory & Application.*
[9] Sailor and Munoz, "Sensitivity of electricity and natural gas consumption."
[10] Sailor, Rosen and Munoz, "Natural gas consumption and climate."
[11] Sailor, "Relating residential and commercial sector electricity loads to climate."
[12] Lee and Levermore, "Weather data for future climate change."
[13] Zheng et al., "Climate-change impacts on electricity demands."
[14] Bach, *Our Threatened Climate.*
[15] See Sailor, "Relating residential and commercial sector electricity loads to climate." and Belzer, Scott, and Sands, "Climate change impacts on energy consumption."

and other third parties, provided that the identity of any customer is not disclosed and cannot be determined.[16] The datasets used in this study were daily observations consisting of half-hourly interval volumes read from smart meters of ComEd customers for the years 2016-2018, identified only by customer class, a random ID number, and geographic location.

4.1.2 Climate/Weather Data

The three-year (2016-2018) climate data was collected from the Synoptic's Mesonet Application Programming Interface (API)[17] for the 166 weather stations across the ComEd service territory, of which, 13 stations were removed due to data unavailability. The data for each weather station included hourly averages of temperature and relative humidity. The location of the selected weather stations can be seen in Figure 1 below. In a few instances when certain parameters were not available for a specific weather station for a period of time, missing values were interpolated using values from the closest station.

Figure 1. Mesonet Weather Stations

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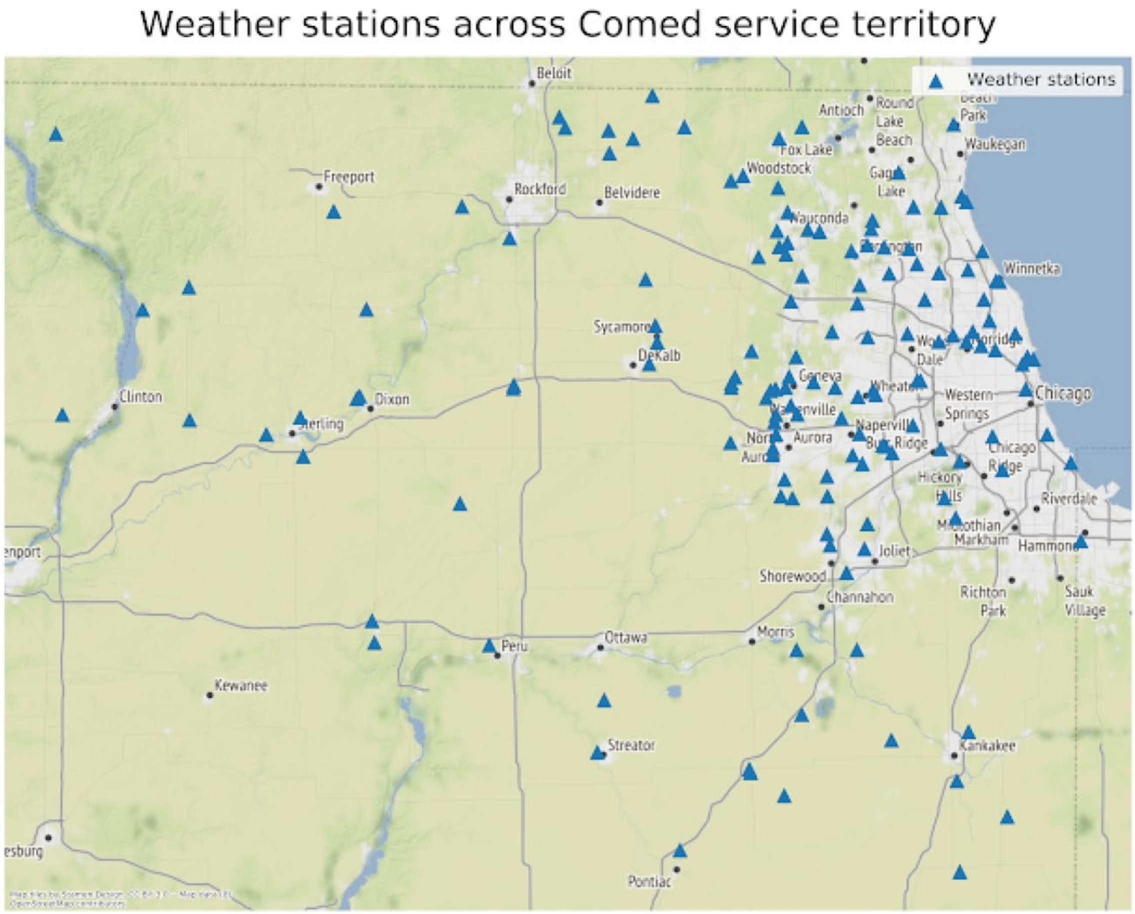
[16] According to the rules approved by ICC, an individual customer's data can only be included in the data release if it passes an anonymity screen. The screen requires that a customer's location cannot be provided if there are 15 or fewer customers in the given geographic area, or if they represent 15% or more of that area's load. See ComEd: An Exelon Company, "Anonymous Data Service." for more information.

[17] Synoptic: Sharing Earth's Data, "Mesonet API."



4.2 Data Cleaning

The smart meter data from ComEd were cleaned for analysis. Half-hourly data were transformed into hourly averages to maintain format compatibility with the local weather data. Customers with any missing data (less than 1% of the total) were removed from the data set. Outliers in the data set were handled by eliminating customers with average daily usage above the 99th percentile and below 1 percentile. The final data set used for analysis contained a total of 15.3 billion total hourly usage observations.

The weather data from 153 stations across the ComEd territory were transformed into weighted hourly averages based on the number of customers in their local range. Each customer in the data set was assigned the closest weather station.[18] We then calculated the population-weighted hourly averages for each parameter in each hour of the three-year period.

Finally, hourly averages of the energy usage data and weather parameters were merged together to form the final data set for analysis, comprising 26,280 hourly averages for three parameters: temperature, relative humidity and average energy usage.

5.0 Usage Models

5.1 Temperature and Humidity

Our temperature projections are based on the results of the Fourth National Climate Assessment, published by the U.S. Global Change Research Program. This report found that annual average temperatures in northern Illinois had increased by 0.3° C by 2018 relative to the observed average temperatures from 1985-2015. [19] Under the RCP8.5 emissions scenario, mid-century average temperatures were projected to increase by 2° C. Therefore, we projected temperatures to increase to 1.2° C in 2030 and 1.7° in the year 2050 relative to 2018 averages.

Using the results of our peak temperature regression model, which estimated peak temperatures to increase 2.2° for every 1° C increase in average annual temperature, we then projected annual peak temperatures for the study period. This resulted in an increase to 2.6° C in 2030 and 3.5° C in 2050.[20]

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[18]We used the Haversine formula to determine proximity. See Gottwald, et al. *The VNR Concise Encyclopedia of Mathematics.*
[19] Hayhoe et al., "Our Changing Climate," 87.
[20] This estimate matches closely with the Fourth National Climate Assessment mid-century projection of 6.7^0 F.

Our humidity projections were taken from the Global Fluid Dynamics Laboratory-Earth Systems Model's RCP8.5 projection.[21]

5.2 Consumption

Increased consumption due to rising temperatures is a primary driver of climate-related electricity costs.[22] To estimate future consumption, we combined the historical weather and AMI data to create a degree-days usage model that takes into account local temperature and humidity. This method uses three variables to estimate total daily usage: cooling degree days (CDD), heating degree days (HDD), and enthalpy latent days (ELD).[23] CDD and HDD are generated by comparing the average daily temperature to a base temperature, or T, in this study 65° F. If the average temperature is above T, we subtracted T from the average and the result is the daily CDD value. If the average temperature is below T, we subtracted the average from T and the result is the HDD. ELD values show the energy required to reduce humidity without changing temperature, allowing our degree day regression to isolate the effects of temperature and humidity.[24], [25]

5.3 Peak Usage

While the degree day model provides a reliable method for predicting total daily usage, it does not include the hourly information necessary to estimate the effect of rising temperatures on peak

[21] Geophysical Fluid Dynamics Laboratory, "Earth System Models."
[22] For a good discussion, particularly with regards to the impact on peak demand, which is a large driver of costs, see Auffhammer, Baylis and Hausman, "Climate change is projected to have severe impacts."
[23]For a clear description of degree days and how they are used in the energy sector, see U.S. Energy Information Administration, "Units and Calculators Explained."
[24] See Appendix A for ELD equation.
[25] See Appendix B, Table 1 for regression results.

demand. To investigate this effect, we developed a model that uses two separate regressions to determine the relationship between average annual temperature and peak demand.

First, a regression was performed using the local weather and AMI data to estimate the relationship between temperature and usage solely during the five coincident peak usage hours of the year.[26] For each of the three years in our historical data set, customer usage during the five highest usage hours was matched with corresponding local weather conditions. A simple multivariate regression was done with hourly volume as the dependent variable and temperature, humidity, and wind speed as independent variables.[27]

The next step was to quantify the relationship between annual average temperature and temperature during the hours of peak usage. To do this, we performed another simple regression analysis using the same peak usage hours from the previous regression, with local temperature as the dependent variable and annual average temperature as the independent variable.[28] The results of these regressions allowed us to calculate the impact of an increase in average annual temperature on peak demand.

6.0 Usage Projections

6.1 Residential Volume

To establish a baseline average daily electricity usage, we calculated the average usage of individual customers in the AMI dataset for each day in 2016-2018. We then projected daily usage for the years 2020-2050 by increasing the local average daily temperatures in the weather

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[26] The five highest coincident peak hours are used to determine the Peak Load Contribution (PLC) obligation by PJM Interconnection, thus we focused on these hours.
[27] See Appendix B, Table 2 for regression results.
[28] See Appendix B, Table 3 for regression results.

dataset by each year's average annual increase and estimated individual customer daily usage, using the results of our degree-days model. An average of these individual usage values was then taken to produce a single daily average usage value for each day of the projection period. By subtracting the 2018 baseline usage values and multiplying the resulting increase or decrease in usage by the number of residential customers, we generated daily and annual usage increase projections for ComEd's residential customer base.

6.2 Peak Usage

Annual increases in residential peak usage were calculated based on each year's projected increase in average temperature, the relationship between annual average temperature and peak temperatures, and the projected effect of local temperature on peak demand usage. We then multiplied this figure by the number of residential customers, giving an end result that is [29] equivalent to the annual increase in the Peak Load Contribution (PLC) of the residential customer class.

7.0 Cost Projections

7.1 Residential Projections

Annual costs to ComEd residential customers for energy, distribution, and transmission services were estimated on a volumetric basis. For each year, the annual increase in total residential usage was multiplied by the sum of projected retail prices for those components, taken from the U.S. Energy Information Administration's (EIA) 2019 Annual Energy Outlook.[30]

[29] We projected the number of residential customers to increase annually according to the historical household formation rate of 0.8%.
[30] U.S. Energy Information Administration, "Table: Electricity Supply, Disposition, Prices, and Emissions."

ComEd currently procures capacity through PJM's annual Base Residual Auction (BRA) process. Annual MW-day increases in required capacity procurement were calculated as the product of the annual increase in residential PLC, 365, and the 9% reserve margin requirement. The increase in capacity cost is the product of this MW-day capacity requirement and the projected capacity prices, which were held level at current prices.[31], [32]

7.2 Non-Residential Projections

Commercial and industrial customers have markedly different usage patterns from residential customers, as well as different heating and cooling requirements. Our AMI dataset included only residential customer usage, from which we extrapolated projected increases in non-residential usage. We projected annual volume changes for non-residential customers by applying the percent change in residential usage to the base case non-residential volume projection, adjusted for the relative difference in proportional heating and cooling load for both classes.

EIA's Residential Energy Consumption and Commercial Building Energy Consumption Surveys shows the average share of annual electricity consumption devoted to heating and cooling for residential and commercial buildings.[33, 34] In the East North Central Census region (that includes Illinois), residential buildings use 27.3% of their annual load for heating and cooling while commercial buildings use 13.8%, on average. Therefore, we estimated the annual change in non-residential volume to equal the base case volume projection, multiplied by the percent change in

[31]The use of current capacity prices going forward is a very conservative assumption—increases in peak load will require building additional generation resources, which almost certainly will increase auction clearing prices.
[32] PJM's BRA process produces a weighted-average MW-day price for an LSE's delivery year capacity obligation – the total capacity cost for the LSE is then the weighted average price multiplied by the number of days in the delivery year, which, in ComEd, is then allocated to customers according to customer class PLCs. *See* PJM Interconnection, *PJM Manual 18: PJM Capacity Market* and Commonwealth Edison, "ComEd Rider PE."
[33] U.S. Energy Information Administration, "Residential Energy Consumption Survey."
[34] U.S. Energy Information Administration, "Commercial Buildings Energy Consumption Survey."

residential volume, further scaled by the ratio of commercial heating and cooling load share to residential heating and cooling load share, or 50.6%.

Because it relies on the historical relationship to residential usage, our estimate for non-residential usage has a lower level of confidence. An area ripe for further research is the specific relationship between industrial and commercial electricity consumption and temperature.

8.0 Results

8.1 Residential Customers

Our degree-days model predicted increased electricity usage for residential customers, rising from a 392 GWh increase in 2020 to 1,838 GWh in 2050, representing a 6.5% increase by the final year, compared with 2018. Residential peak usage grew by 119 MW in 2020, rising to 1,210 additional MWs by 2050—a much faster growth rate of 12.3%, as of 2050. Overall residential customer bill increases would total $49 million in 2020, rising annually to $284 million in 2050, a 7.7% bill increase over the base case.

Figure 2. Residential Volume and Peak Load Increase[35]

[35] The spikes in annual volume in Figure 2 through Figure 7 are a consequence of the periodic weather fluctuations included in climate models because of the complex nature of weather systems. The impact of humidity is primarily relevant above a certain temperature when there are a large(r) number of cooling degree days. So the overall trend is up but on a year-to-year basis there are spikes due to projected periodic weather fluctuation around the number of CDDs.

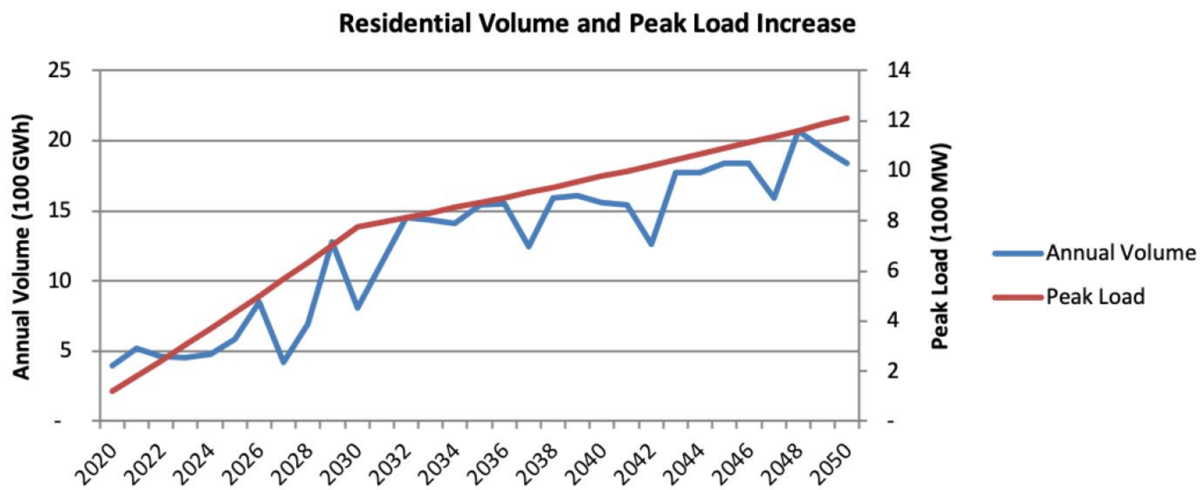


Figure 3. Annual Residential Cost Increase

8.2 Non-Residential Customers

Non-residential volume was projected based on the historical ratios of residential and non-residential annual usage. We estimated non-residential consumption to begin increasing due to climate change in 2020, with an increase of 443 GWh. This increase continued through 2050, resulting in 2,150 GWh in additional usage—a 3.3% increase over the base case. The cumulative increase would be 45.5 TWh. While these results show a higher total increase in volume for non-residential customers, it is a lower percentage increase than for residential customers, due to the smaller share of total heating and cooling load for commercial and industrial customers. We estimated the total non-residential increase in peak usage due to climate change to reach almost 98 MW in 2050. Non-residential customers begin seeing higher bills in 2020, with annual increases up to $233 million in 2050, a 3% increase over the base case. The cumulative non-residential cost increase over the course of the study is $4.9 billion.

Figure 4. Annual Non-Residential Volume and Peak Load Increase

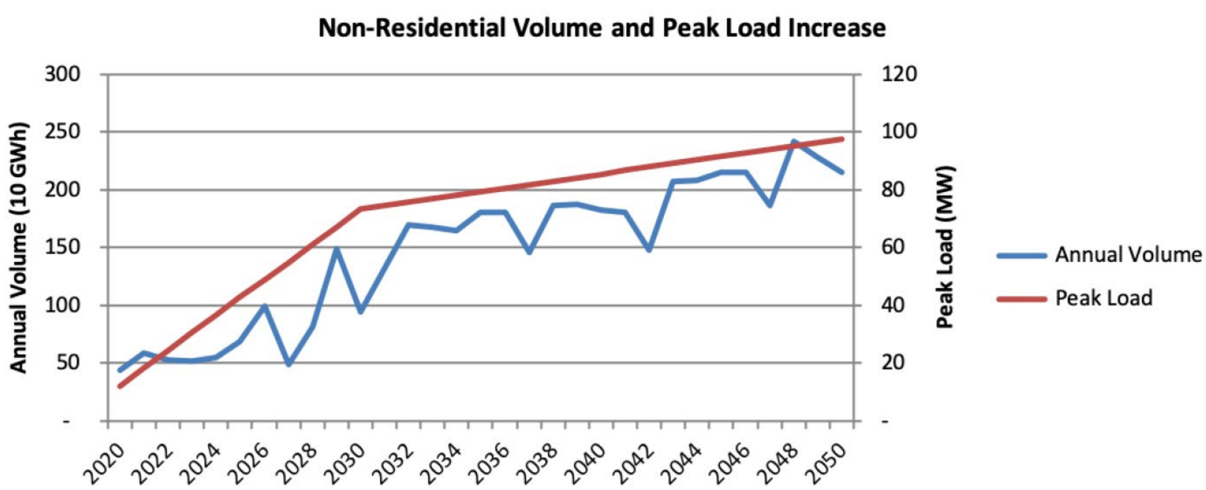
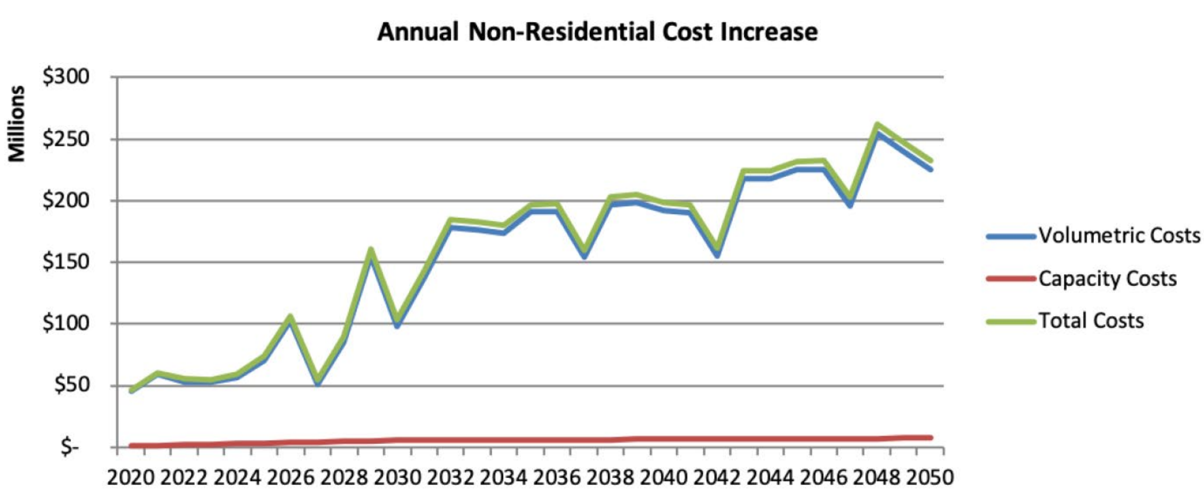


Figure 5. Annual Non-Residential Cost Increase



8.3 All Customers

The total climate-related usage increase for all ComEd customers is a cumulative 84.4 TWh by 2050, a 4.3% increase over the base case. The combined peak load for all ComEd customers is estimated to increase by 1.31 GW in 2050, a 5.7% increase. ComEd customers are estimated to begin seeing higher bills due to climate change beginning in 2020, with total increased costs of $95 million, rising to $517 million in 2050, a 4.5% increase over the base case. The total temperature-related increase over the study period is $10.9 billion (2018 USD).

Figure 6. Annual Volume and Peak Load Increases, All Classes

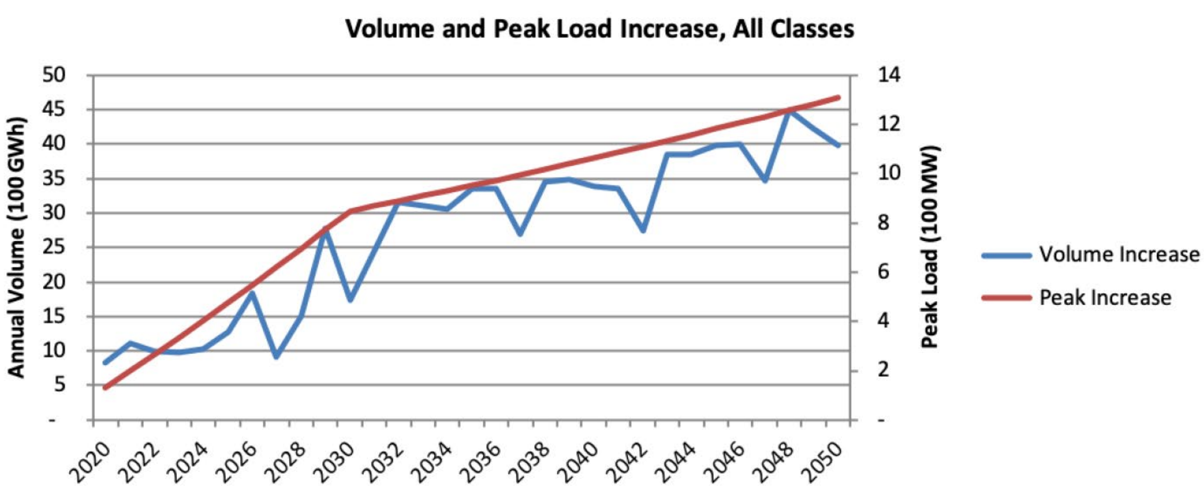
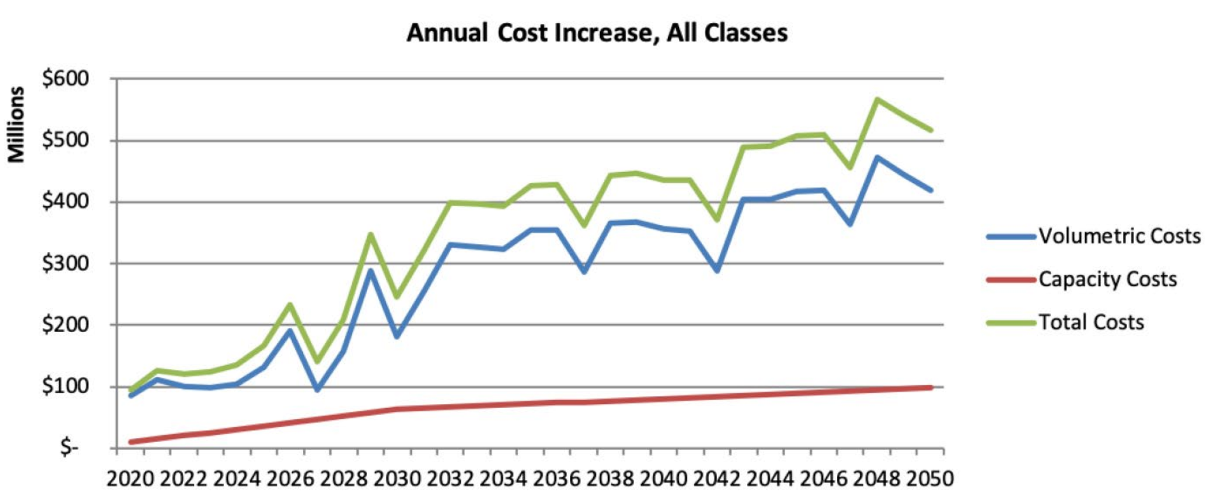


Figure 7. Annual Cost Increase, All Classes



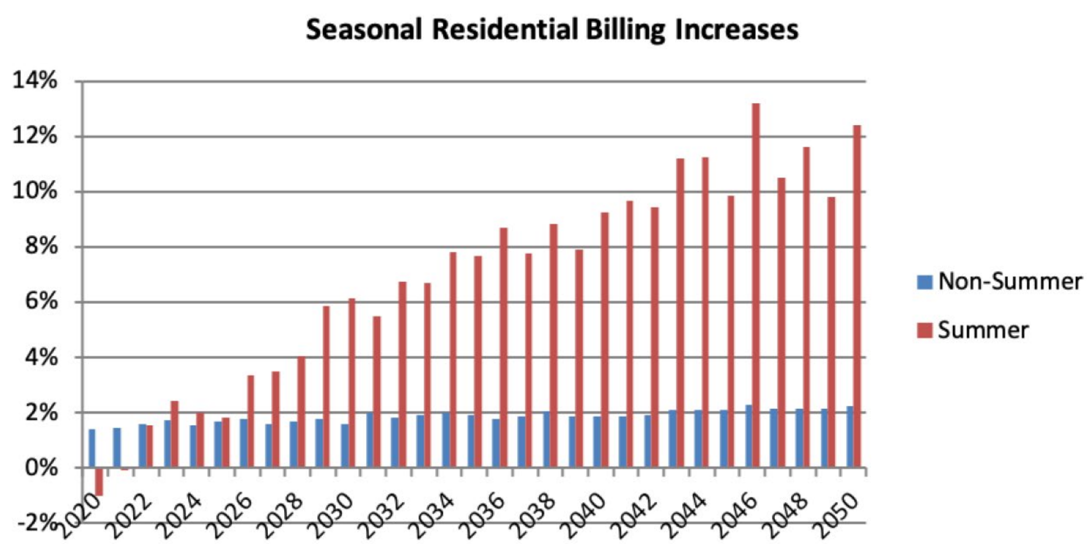
9.0 Discussion

This study employed newly available AMI data to estimate the increased usage due to warming weather in northern Illinois through 2050, and projected its effect on consumer costs. The analysis showed that—in the absence of effective measures to reduce emissions and improve system efficiency by reducing peak demand—climate change will increase overall ComEd customer costs by at least $10.9 billion. While the overall annual temperature-driven percentage increase in costs over the 30-year period for all customer classes averaged 3.2%, it increased every year, rising to 4.5% in 2050. Moreover, as previously shown, the residential sector increase is significantly higher: averaging 7.7% in higher costs. Particularly in low-income communities where utility costs amount to a high proportion of household income, increased costs because of climate change would pose a significant burden.

A significant difference in the cost impacts of residential and non-residential customers is in capacity cost responsibility. Our model predicts a higher increase in peak demand for residential customers, due to their proportion of heating and cooling load and larger customer base. Currently, non-residential customers make up the majority of overall ComEd capacity costs. Our results suggest that residential cooling demand will begin to tip that balance, as residential consumers begin to bear a higher cost for the region's capacity needs in the absence of effective policies that reduce peak load and improve system efficiency.

It is also important to note that cost increases due to rising temperatures will be concentrated in the summer months, when cooling costs are highest. Figure 8 compares the annual change in volume between Summer (May-September) and Non-Summer (October-March) billing periods. In the first decade, non-summer bills would increase by an average of 1.6% while summer bills would increase by 2.7%. By the final decade, average non-summer bill increases would rise to 2.1%, while average summer bill increases would rise to 10.9%.

Figure 8. Seasonal Residential Billing Increases



We emphasize that our results are conservative projections that do not include higher costs due to population growth or increased electricity usage driven by electrification of transportation and heat. Also, our projections are based only on weather-related changes in electricity consumption. They do not include increases in the component costs of electricity associated with expensive transmission and distribution system upgrades, lower system efficiency if hotter summers contribute to 'peakier' load shapes, increased energy costs due to continued reliance on high marginal-cost fossil-fuel generation, and higher market energy and capacity prices due to increased demand.[36] These factors will almost certainly result in enormous new costs and are ripe for modeling in future analyses.

The study results highlight the growing importance of peak demand as a cost driver in an era of climate change and the concomitant consumer benefits that can be achieved from peak-demand reductions. While increased volumetric costs constitute a significant portion of projected cost increases, capacity-related increases indicate efforts to manage peak usage, which can mitigate the consumer costs of climate change even if usage volume rises. If, for example, annual volume increases are held constant but the annual increase in peak usage is limited by 20%, the final cumulative cost increase is lessened by $373 million, a 3.4% reduction. If the peak usage impact is limited by 50%, the savings compared with the base case increase to $934 million, a 8.6% reduction.

The higher electricity costs under a business-as-usual approach and the substantial savings that would be achieved by a successful mitigation strategy show the value of public policies designed to reduce consumption and optimize system load shapes. Costs for delivering electricity and market energy prices would decline along with carbon emissions if peak usage were curtailed. Effective peak-reduction strategies and load shaping efforts are therefore critical to success in addressing the twin challenges of higher emissions and higher costs.

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[36] This assumes minimal change to the current generation mix, a necessary assumption of the RCP 8.5 emissions pathway.

The right set of public policies can not only mitigate climate change through replacement of fossil fuels with carbon-free resources, but substantially reduce consumer costs. The regulatory policy levers are well known: energy efficiency initiatives, price responsive demand, innovative rate plans such as hourly pricing and time-of-use rates, central load control programs, and deployment of energy storage and distributed resources where cost-effective.

These load-shaping policies are largely under the purview of state regulators operating under statutory goals and standards. Each jurisdiction must identify the most cost-effective approaches, given differences in existing generation mix, deployment of advanced metering, market structure, geo-demographic characteristics, and other factors of state and local concern. But the huge financial and environmental benefits make optimizing the electric system an urgent task in all jurisdictions.

It is far from the only task. We conclude from this study—the first to employ newly available granular smart grid data to quantify the effect of rising temperatures on electricity costs—that the adverse effect on consumers from climate change will be substantial. Under conservative assumptions, higher electricity costs for consumers in just one Illinois utility service territory will amount to $10.9 billion by 2050. Were similar data available for the other 49 states, the national scale of costs to result from this single element of unchecked climate change could be precisely projected. It is clear from the data that addressing climate change has consumer benefits and that effective climate change mitigation strategies should be a priority for least-cost energy planning.

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Appendix A. Referenced Formulae

Enthalpy Latent Days

Where E is enthalpy and *a* is the enthalpy at measured temperature and humidity ratio of 0.0116.

In the equation,

$$ELD = \frac{1}{24}\sum_{1}^{24} a(E - E_0)$$

- a = 0, if the temperature is below 78° or if the enthalpy difference is 0 and
- a = 1, if the temperature is above 78°.

Appendix B. Regression Results

Table 1. Regression Results for Average Daily Daily Usage (standard deviations from the mean)

Constant	11.17***
	(85.28)
Heating Degree Days	0.288***
	(45.02)
Cooling Degree Days	2.005***
	(62.98)
Enthalpy Latent Days	0.190***
	(8.103)
Wind Speed	-0.121***
	(-5.158)
R-squared	0.917
No. Observations	1096

Standard errors reported in parentheses. *, **, *** indicates significance at the 90%, 95%, and 99% level, respectively.

Table 2. Regression Results for Peak Hour Usage (standard deviations from the mean)

Local Temperature	0.0754***
	(2.8e-05)
Local Humidity	0.0027***
	(1.1e-05)
Local Wind Speed	-0.017***
	(5.8e-05)
R-squared	0.619
No. Observations	37,300,665

Standard errors reported in parentheses. *, **, *** indicates significance at the 90%, 95%, and 99% level, respectively.

Table 3. Regression Results for Peak Usage Hour Temperature (standard deviations from the mean)

Average Annual	2.159***
Temperature	(0.028)
R-squared	0.951
No. Observations	298

Standard errors reported in parentheses. *, **, *** indicates significance at the 90%, 95%, and 99% level, respectively.