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Multiscale effects masked the impact of the COVID-19 pandemic on electricity demand in the United States

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HIGHLIGHTS

• COVID-19 modified when, where, and how we use electricity.
• The impact of COVID-19 varied across spatiotemporal scales.
• There are multiple offsetting effects that can mask the impact of COVID-19 on electricity demand.

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ABSTRACT

Shelter-in-place orders and business closures related to COVID-19 changed the hourly profile of electricity demand and created an unprecedented source of uncertainty for the grid. The potential for continued shifts in electricity profiles has implications for electricity sector investment and operating decisions that maintain reserve margins and provide grid reliability. This study reveals that understanding this uncertainty requires an understanding of the underlying drivers at the customer-class scale. This paper utilizes three datasets to compare the impacts of COVID-19 on electricity consumption across a range of spatiotemporal and customer scales. At the utility/customer-class scale, COVID-19-induced shutdowns in the spring of 2020 shifted weekday residential load profiles to resemble weekend profiles from previous years. Total commercial loads declined, but the commercial diurnal load profile was unchanged. With only total loads available at the balancing authority scale, the apparent impact of COVID-19 was smaller during the summer due in part to phased re-opening and spatial variability in re-opening, but there were still clear variations once total loads were broken down zonally. Monthly data at the state scale showed an increase in state-level residential electricity sales, a decrease in commercial sales, and a small net decrease in total sales in most states from April-August 2020. Analyses that focus on total load or a single scale may miss important changes that become apparent when the load is broken down regionally or by customer class.

1. Introduction

Understanding and predicting the diurnal profile of electricity demand (also called load) is critical for planning economically efficient electricity grid operations, designing rates, and evaluating infrastructure and market policies [1,2,3,4]. Grid operators rely on load forecasts that are highly dependent on the day of week and time of year, holidays, and medium-range weather forecasts [3]. While most of the load forecast uncertainty at these time scales is typically driven by uncertainty in weather forecasting [5,6], behavioral and economic shifts during the COVID-19 pandemic and their potential to persist beyond the current crisis are introducing new uncertainties [7].

Shelter-in-place measures to limit the viral spread of COVID-19 during the spring of 2020 disrupted the ways in which people work, learn, and socialize. These disruptions modified and may continue to modify when, where, and how we use electricity. For example, several large companies in the United States (U.S.) and United Kingdom have announced plans to allow for widespread permanent teleworking even after employees are allowed back into the office [8,9,10]. A recent Pew Research Center survey found that most of those working from home were not doing so before the pandemic and the majority of the teleworkers surveyed would prefer to keep working from home after the pandemic [11,12].

Teleworking and stay-at-home orders resulting from COVID-19 caused increases in residential electricity demand and decreases in commercial and industrial demand [13,14,15,16,17]. In the U.S., the Energy Information Administration (EIA) reported that nationwide total energy consumption in April 2020 dropped to its lowest level for any single month since September 1989 [18]. The changes in electricity consumption varied by sector. Residential electricity sales were 6%
higher in April 2020 than in any April of the five previous years while commercial and industrial sales decreased by 11% and 9%, respectively, compared with April 2019 [16]. Overall, electricity demand and prices dropped markedly in multiple electricity markets in the U.S. [19]. In an analysis of integrated electricity market data across the U.S., Ruan et al. found reductions relative to a backcast estimation (no COVID-19 scenario) of 6.4% – 10.2% in April and 4.4% – 10.7% in May [20]. They correlated reductions in electricity consumption in populous cities with reduced commercial activity and an increase in the stay-at-home population [20].

There were also shifts in the diurnal profile of electricity consumption associated with COVID-19. A blog post from the New York Independent System Operator (NYISO) reported later-than-normal morning peaks, higher midday residential energy use, and temporal patterns similar to “a widespread snow day” [7]. A comparison of electricity demand profiles across Europe during the second week of April 2020 showed that total weekday electricity consumption was considerably reduced in countries that instituted COVID-19 containment measures and that the weekday hourly profiles resembled pre-pandemic weekend profiles [21]. COVID-19-induced deviations from normal diurnal patterns of electricity consumption in the residential and commercial sectors appears to have contributed to several notable spikes in the error of day-ahead forecasts that underpin the electricity market in the U.S. (Fig. 1). While some of the U.S. reserve regions examined had minimal changes in the distribution of their errors, several had significant spikes or increases in the variability of their forecast error after the onset of COVID-19-induced shutdowns in March of 2020 (e.g., the Carolinas and the Midwest).

The potential for increased uncertainty due to long-term changes induced by COVID-19 will create challenges in predicting future hourly load profiles. Accurate hourly load forecasts are critical for both short-term operations and longer-term planning. These projections need to capture sectoral and geographical differences, as a decrease in overall electricity consumption but overall higher diurnal load profile uncertainty can affect regional production costs, ancillary service needs and investment costs (e.g., ramping and storage), and market prices differently [22,23]. For example, the effect of the pandemic on electricity demand has been shown to differ among residential, commercial, and industrial sectors [16,15] and the effect of the pandemic on electricity generation fuel mixes has been shown to differ among the three U.S. Regional Transmission Organizations (RTOs) [24]. Future load profiles will need to reflect societal changes that were not present in pre-COVID-19 operational and long-term studies. Prior research on the energy and climate impacts of teleworking has focused primarily on changes in vehicle distance traveled, with overall energy use being a secondary focus [25]. While some pre-COVID-19 studies have addressed the impacts of teleworking on total energy use in the residential and commercial sectors [26,27], their results were provided at annual time scales as opposed to hourly.

This paper addresses a need for new research investigating the impacts of COVID-19 on hourly electricity load profiles by customer class within a given region of the electrical grid, complemented with insights on how these hourly profile changes vary across spatiotemporal scales. The novelty of this work is that we analyzed three independent datasets of observed electricity consumption differing by spatiotemporal scale and level of customer data aggregation to explore how these differences affected our ability to detect changes in electricity demand due to COVID-19. Our work expands upon the growing literature on impacts of COVID-19 on electricity consumption, most of which is focused on a single scale or sector. The electricity sector in the U.S. is composed of a series of nested actors (e.g., customers, utilities, balancing authorities [BAs], and RTOs), each of whose decisions affect outcomes at both larger and smaller spatial scales. For example, local utilities make decisions regarding rates and infrastructure buildout while RTOs lead long-term resource adequacy planning efforts and BAs are responsible for real-time balancing of supply and demand. We will show that COVID-19 impacted the electric sector in a variety of ways and that the apparent nature of those impacts varied depending on spatiotemporal and sectoral scales. We highlight several types of offsetting effects that acted to mute the COVID-19 signal. Our analysis suggests that modeling diurnal load patterns by customer class is necessary not only to understand recent changes in the total load profile due to COVID-19, but also to improve future load forecasts to account for the persistence of COVID-19-induced changes in patterns of electricity consumption.

![Fig. 1. Time series of day-ahead forecast error from the EIA-930 dataset (https://www.eia.gov/beta/electricity/gridmonitor/dashboard/electric_overview/US48/US48) in multiple regions within the U.S. Errors are smoothed using a 21-day running mean. To show changes pre- and post-COVID, the mean error +/-1 standard deviation before (red) and after (blue) 15-March 2020 are plotted on top of the error time series.](https://www.eia.gov/beta/electricity/gridmonitor/dashboard/electric_overview/US48/US48)
2. Data and methods

We brought together three unique datasets in order to show how the impact of COVID-19 varied across a range of spatiotemporal scales (Table 1). This use of three different datasets is driven by a lack of homogenous, high spatiotemporal resolution electricity data across the entire U.S. Combined, these three datasets provide a comprehensive view of the impact of COVID-19 on electricity consumption patterns at a range of scales from hourly demand for individual customers all the way up to monthly impacts at the state level. Using three datasets allows us to compare and contrast how the scale differences between each dataset impact the ability to isolate the impact of COVID-19.

We start by first examining changes in the hourly demand for electricity by customer class for a single utility using 30-minute anonymized electricity usage data available from the Commonwealth Edison (ComEd) utility. The ComEd service territory spans all or part of 24 counties in northern Illinois, including Cook County and the greater Chicago metropolitan area (Fig. 2). The ComEd Anonymous Data Service (ADS; [28]), available for a fee, covers ComEd customers where Advanced Metering Infrastructure devices have been deployed. To our knowledge, it is one of the few publicly available datasets of its type in the U.S. Anonymized electricity consumption data are classified by customer class (4 residential and 11 non-residential customer classes) and zip code. While the number of customers in the ADS varies from month to month, an average month has more than 3.5 million residential customer records and 330,000 non-residential customer records. This constitutes nearly all of the 3.65 million residential and 386,000 non-residential customers ComEd reported in 2018 [29]. This study uses ADS data from April 2018 through September 2020. The raw ADS metered electricity consumption data (kWh) is in 30-minute intervals for each customer. We aggregate these into residential and non-residential customer classes. We then convert the units from kWh per 0.5 h to MWh per h (a multiplier of 1000/2 kW/MW).

We next use the EIA-930 hourly electricity grid monitoring data (https://www.eia.gov/beta/electricity/gridmonitor/dashboard/electric_overview/US48/US48) to examine changes in hourly total load profiles at the BA scale, with a focus on the BA containing the ComEd service territory, the PJM Interconnection. Balancing authorities are responsible for real-time balancing of supply and demand for electricity within defined load-balancing areas. Because BAs use day-ahead load forecasting (primarily driven by weather forecasts and the day of the week) to adjust expected demand and minimize costs to the end-user, day-ahead planning is sensitive to anomalous conditions such as COVID-19 that may cause their forecasts to deviate from reality (e.g., Fig. 1). The PJM Interconnection governs the delivery of electricity within parts of thirteen states and the upper midwest of the U.S (Fig 2). It is an interesting case study for analyzing COVID-19 impacts both because of its size (PJM is a substantial fraction of total electricity served in the entire eastern interconnection) and the fact that it spans more than a dozen states, each of which responded to COVID-19 in different ways. Total hourly demand in the PJM BA is available in the EIA-930 dataset as is hourly demand for each of the 20 zones within PJM. We use PJM load data from 2018 through 2020. Using multiple years of data allows us to place the changes due to COVID-19 in the context of historical variability. For context, the BA-scale analysis was repeated for two additional large BAs (the California Independent System Operator [CISO] and New York Independent System Operator [NYISO]) in the Supplemental Material.

Our final analysis explores COVID-19-induced changes at the state scale. Only monthly data are available for this analysis. The EIA-861M dataset (https://www.eia.gov/electricity/data/eia861/) reports monthly sales of electricity by sector (residential, commercial, industrial, and transportation) for each of the 50 U.S. states and Washington, D.C. State-level sales data is available from January 1990 through December of 2020. We use this dataset to compute monthly year-over-year changes in sales of electricity. To examine the impact of COVID-19, we computed the monthly year-over-year change in total, residential, and commercial electricity sales for each state in 2020 compared to 2019. These year-over-year changes were also computed for every year going back to 1990 in order to put the COVID-19 changes in the context of historical variability. The state scale analysis has implications for policy which in turn influences long-term planning.

3. Results

We performed three unique analyses of the impact of COVID-19 on electricity demand across a range of spatiotemporal scales starting from the finest span-time temporal scale and gradually upscaling to monthly state-level sales of electricity. In each section we examine two basic questions:

1. How did COVID-19 impact the ways in which we consume electricity in the U.S.?
2. When did these changes appear and when are they no longer apparent?

3.1. Changes in hourly loads by customer class at the utility scale

The ComEd dataset facilitates an analysis of COVID-19 impacts on an hourly basis by customer class at the utility scale. We start by focusing in detail on the changes observed in February-April 2020 which corresponds to the onset of COVID-19 in the U.S. To do this, we compare total, residential, and non-residential hourly weekday loads between February 3 and April 30, 2020 (Fig. 3). A mandatory shelter-in-place order for the state of Illinois was issued on 20-March 2020 [30]. The impact of this order is evident in the ComEd data starting the week of 16-March 2020. Total loads declined across the diurnal cycle after the order was issued (Fig. 3a). This was likely due to a combination of decreasing non-residential loads associated with business closures (Fig. 3c), although it may be possible that gradual springtime warming also played a role. The normalized total loads show a more gradual early morning ramp, higher midday loads, and a later and less steep evening ramp (Fig. 3d). Disaggregating the load by customer classes highlights the different changes in the residential and non-residential load profiles (Fig. 3b,c). While non-residential loads declined, the non-residential load shape was largely unaffected (Fig. 3c,f). In contrast, the residential weekday load profile showed a dramatic change in shape consistent with changes in the total load profile, with a more gradual morning ramp, higher midday loads, and a smaller and less steep ramp to the evening peak (Fig. 3b,e).

Changes to the mean residential load profiles in April 2020 are consistent with people not waking up as early, not departing for work en ~
mass between 7 am – 8 am, and using electricity at home more consistently throughout the day. The April 2020 residential weekday profiles closely resemble the residential weekend load profiles for April in 2018 and 2019 (Fig. 4b). This transition to ‘perpetual weekend’ load profiles is consistent with NYISO’s observation of load profiles similar to “a widespread snow day” [7]. Before the COVID-19 shutdown, weekday residential evening ramps were commonly greater than + 1000 MW in a 3-hour period in February 2020. After 16-March weekday residential load profiles had ramps that were half as steep. Total April 2020 weekday electricity consumption for non-residential customers was 16% lower than in April 2019 while consumption for residential customers was 12% higher. This may be due in part to year-to-year changes in weather, but the changes in the shape of the load profiles are more consistent with impacts of the shelter-in-place order.

Our first analysis showed that the COVID-19 shutdowns in February-April 2020 dramatically shifted the patterns of electricity consumption for both residential and non-residential customers of the ComEd utility. Our next question is to examine how long those changes persisted. The most obvious changes to the load profiles resulted from people staying at home on weekdays and thus minimizing the difference between weekday and weekend load profiles for residential customers. Using this finding, we next compare monthly snapshots of average weekday and weekend load profiles across the first six months of Illinois’ pandemic response as a measure to gauge the persistence of COVID-19 impacts (Fig. 4 and Figs. S1-S3 in the Supplemental Material). The top row shows the mean weekday and weekend load profiles in April as a means of
connecting to the first analysis in this section. The patterns discussed above are still readily apparent in this plotting convention—most notably the shift of weekday residential load profiles to resemble weekend load profiles of previous years (Fig. 4b).

The impact of COVID-19 shutdowns became harder to see during the transition from the spring to summer months of 2020. In particular, the diurnal cycle of the total load in July 2020 was indistinguishable from previous years (Fig. 4d). There are a few likely reasons why this is happening. First, the shutdown in Illinois was near total in the spring whereas some summer months were still relatively shutdown while others had somewhat returned to normal. For example, some businesses had re-opened while a substantial portion of the population continued to do remote learning and teleworking. Secondly and perhaps more importantly, load profiles in the spring and fall are less dependent on external temperatures and more dependent on occupancy schedules (e.g., when and where people use electricity) compared to the summer. In the summer, loads are more strongly driven by air conditioning demands and electricity consumption for cooling is impacted much more strongly by temperature when temperatures are high (i.e., summer) compared with when temperatures are milder (e.g., [31,32]). As such people staying home during the day has a relatively smaller impact. A temperature-driven load profile also reduces the difference between weekday and weekend total load profiles and thus obscure the ‘perpetual weekend’ signal that was apparent in April. Even in July there are still clear variations in the load profile if you break the ComEd data down into its residential and non-residential components (Fig. 4e,f). Residential loads in July were noticeably higher during the day and had a shape closer to the weekend profile from 2019 (Fig. 4e). This is consistent with people staying home and using more electricity during the day. Non-residential weekday loads in July were suppressed compared to the previous two years (Fig. 4f).

Changes in the shape of the total load profile re-emerged by September (the last month for which we had data). The total weekday load profile in September of 2020 had a similar shape as the weekday profiles from 2018 and 2019 (Fig. 4g). Residential loads in September again showed the absence of the morning bump associated with people getting up and leaving for work (Fig. 4h). Non-residential loads in September remained suppressed, but maintained a shape consistent with previous years (Fig. 4i).

Overall, at the utility scale we noted a series of changes for both residential and non-residential customers after the onset of COVID-19. Of interest to operational planners and consistent with previous results, we found a change in the shape of mean weekday load profiles in the spring of 2020 such that weekday total load profiles looked like weekend profiles from previous years. We were further able to explain these differences by isolating residential and non-residential responses to COVID-19. Changes in the shape of the residential load profile and in the magnitude of non-residential loads persisted through September 2020—the last month of ComEd data that we had. Our analysis at this scale suggests that maintaining a distinction between residential and non-residential loads could enhance utility-scale load forecasting models that are typically based on the day of the week, day of the year, and meteorology.

3.2. Changes at the balancing authority scale

Scaling up from an individual utility with customer-class resolution load data, we next analyzed changes in the shape of the hourly diurnal load profile at the BA scale to discuss the potential impact of COVID-19 on grid operations. For this analysis we used data from the PJM BA in the eastern U.S. (Fig. 2). Total electricity loads were used because the data publicly available at this scale is not broken down into its residential and non-residential components. We analyzed two additional large BAs (CISO and NYISO) in a similar manner. Those results are included in the Supplemental Material (Figs. S4-S5) but are not discussed in the text.

The diurnal cycle of average total demand on weekdays and weekends from 2018 to 2020 is shown in Fig. 5. Several features are consistent with the earlier patterns from the ComEd dataset. Total loads were
reduced in March, April, and May of 2020 (Fig. 5c,d,e). Importantly, the reduction in total loads in the spring of 2020 was noticeably larger than the change observed between 2018 and 2019. This suggests that the changes in the spring of 2020 were not due to natural weather-driven year-to-year variability. The weekday PJM data also showed a shift to a more weekend-like load profile after the onset of COVID-19 shutdowns in March-May 2020 (Fig. 5c,d,e).

The changes due to COVID-19 after June of 2020 are harder to see and are in many cases similar to the scale of interannual variability from prior years (i.e., the changes from 2019 to 2020 for a given month are of the same magnitude as the changes from 2018 to 2019). The inability to break the load down into residential and non-residential components

Fig. 5. The diurnal profile of mean weekday (solid lines) and weekend (dashed lines) total load profiles in the PJM BA by month in 2018 (cyan lines), 2019 (blue lines), and 2020 (magenta lines).

Fig. 6. The change in average load by month between 2019 and 2020 (i.e., the mean in 2019 – the mean in 2020) as a function of time of day for 19 zones within the PJM BA. Each zone is shown as a distinct color. Changes are expressed as a difference relative to the 2019 values.
makes the obvious shifts that were visible in the customer-class ComEd data in July and September harder to spot in the BA-level data. Phased re-openings and variability in openness across a region as large as the PJM BA further complicates things because the heterogeneity in local responses to the pandemic means there are no clear demarcations between “open” and “shut-down” months.

While the changes in total load for PJM are minimal in the summer, examining the load profiles in individual zones within PJM shows the summertime changes apparent in the ComEd data starting to re-appear (Fig. 6 for PJM and Figs. S6-S7 in the Supplemental Material for CISO and NYISO). Here we show the difference between the 2019 and 2020 weekday average load as a function of time of day for each of the 19 PJM zones with quality data in both years. One additional zone had questionable data in 2019 which made the comparison across years invalid. It is illustrative to look at the patterns in January and February (Fig. 6a, b) as a means of benchmarking the COVID-19-induced patterns that started in March (Fig. 6c). While there were year-over-year changes in both January and February, all but one of the PJM zones have approximately the same magnitude year-over-year change (i.e., there is little variability from zone-to-zone). More importantly, the changes in January and February vary little throughout the day (i.e., the lines are flat).

This is in contrast to the changes after March 2020 (Fig. 6c-l) when the differences are larger, have a diurnal structure reflective of changing schedules of when and where people consume electricity, and have significantly more variability from zone to zone. The increased zone-to-zone variability likely reflects the fact that there was significant variation in re-opening from state to state and even between cities or counties within a state. Even in the summer months when it is hard to see any signal in total load for all of PJM (e.g., Fig. 5f,g,h), there are still a handful of zones with clear structural changes in their average load (Fig. 6f,g,h). Loads were suppressed during the early morning hours before people traditionally leave for work. The changes then gradually become more positive during the afternoon. In June, July, and August there are some zones with net positive year-to-year changes and some with net decreases (Fig. 6f,g,h). This suggests that there may be offsetting effects when the changes are summed across all 19 zones in PJM.

In summary, the total load response to COVID-19 appears more muted at the BA scale of PJM than at the ComEd scale where we could subdivide the load into its residential and non-residential components. For the BA as a whole, the shift toward weekend-like load profiles occurring on weekdays is recognizable in the spring of 2020 but becomes undiscernible after June. Weekend and weekday load profiles are very similar during the summer due to being more dependent on diurnal temperature changes. However, breaking the data into individual zones within PJM shows that changes in the total load profile due to COVID-19 persisted in some zones all the way through the summer. This analysis suggests that while PJM as a whole may have been relatively unaffected in the summer of 2020, persistent shutdowns associated with COVID-19 may have altered the power grid dynamics and the flow of electricity from zone to zone throughout the summer.

3.3. Changes at the state scale

Our final analysis looks at changes in electricity sales in 2020 at the state scale. In addition to providing another scale to compare and contrast, the long data record at the state scale also allows us to put changes observed in 2020 in perspective with the magnitude of historical inter-annual variability. We start by analyzing changes in total electricity sales for each year from 1990 to 2019 and from 2019 to 2020 (Fig. 7) and then break the sales down by residential and commercial customers to diagnose the sector-specific impacts of COVID-19 (Fig. 8). Historically, the normalized year-over-year changes in total electricity sales has a slightly positive mean (+1.4%) a standard deviation of +/-5.9%. The historical mean +/-1, 2, and 3 standard deviations is shown in these figures as a means of evaluating the magnitude of the changes in 2020 compared to historical variability.

Consistent with our results above and previous results, total electricity consumption decreased in the spring of 2020. While the distribution of the year-over-year changes from 2019 to 2020 was obviously shifted to the lower (left) side of the historical variability, the changes in

Fig. 7. Monthly frequency distributions of the year-over-year changes in the electricity consumption of states before COVID (dashed lines) and after COVID (solid lines). Distributions are shown for the change in total electricity sales. Each state and each year-over-year change is a unique data point that contributes to the distribution. The vertical gray line and gray shading in the background shows the 19-year pre-COVID mean +/-1, 2, and 3 (darker to lighter) standard deviations.
March-May of 2020 were not dramatically more negative compared to January or February of 2020 which were not impacted by COVID-19. By the summer, the mode of the year-over-year change in total electricity was still negative, but the distribution of changes overlapped significantly with the distribution of historical changes. This confirms that our previous finding of a muted impact in the summer also translates to the state scale. In the fall, the year-over-year change was again negative and looked similar to changes observed in the spring of 2020.

As with the ComEd and PJM data, breaking down the state-level data by sector clarifies the impact of COVID-19. The monthly distributions of year-over-year changes of electricity sales to residential and commercial customers are shown in Fig. 8. Consistent with the ComEd data, April 2020 commercial sales decreased sharply while residential sales were weakly positive compared to 2019. The modal change in commercial electricity sales was more than three standard deviations from the historical variability in both April and May of 2020 (Fig. 8d,e). Examining the residential and commercial changes separately also highlights the fact that COVID-19-induced changes likely continued through the summer of 2020 with residential sales being consistently higher than 2019 and commercial sales lower.

The fact that residential and commercial sales moved in opposite directions in 2020 was itself a historical anomaly. For the period from 1990 to 2019, the year-over-year changes in residential and commercial electricity sales had the same sign more than 70% of the time (not shown). This may reflect the fact that year-over-year changes are largely driven by weather variability and population or economic growth, each of which would likely enhance or suppress residential and commercial electricity consumption in similar ways. However, after February of 2020 residential and commercial sales moved in opposite directions nearly 65% of the time – a near complete reversal from the historical trend (not shown). The fact that sales moved in opposite directions for these two key customer classes also helps to explain why the total load changes were not substantially different in the summer of 2020 compared to the historical period (Fig. 7f,g,h). At the state level, these two key sectors moving in opposite directions masked truly historical anomalies when the year-over-year changes in the residential and commercial sectors are analyzed independently. Those historical results, influenced by shelter-in-place orders and school and business closures, provide a basis for integrated long-term planning. Such changes would impact potential critical infrastructure development for states such as location of new substations, the optimal siting of grid-scale batteries, and potential system responses to extreme events.

4. Conclusions

COVID-19 induced substantial changes in when and where we use electricity and created an unprecedented source of uncertainty for the electric grid. The primary outcome of our analysis is to show that the apparent impact of COVID-19 varied depending on the spatiotemporal scale and level of aggregation of data being examined. At every scale COVID-19 impacts first appeared in the spring of 2020 and persisted at least through the fall of 2020. We identified three factors that acted to mask the impact of COVID-19:

1. Across all three scales we examined, the impact of COVID-19 was dampened because changes in residential loads and non-residential loads had a similar magnitude but moved in opposite directions.
2. During the summer of 2020 total loads became more strongly dependent on diurnal temperature variations and less dependent on inhabitance schedules. This acted to reduce the impact of more people staying home during the day – a signal that was clearly evident in the spring and then re-emerged in the fall of 2020.
3. Phased reopening and spatial variability in reopening during the summer of 2020 masked the COVID-19 signal when total load data were analyzed at the balancing authority scale. Breaking the data down into smaller zones within the balancing authority showed that the impact of COVID-19 persisted through the summer and into the fall of 2020.

5. Discussion

Because there were offsetting signals, some of the trends we identified would not have shown up as clearly if we only had total load data. A longer record of granular (e.g., sectoral or by customer class) electricity consumption data would help to isolate changes due to the natural year-to-year changes driven by weather variability and changes due solely to the pandemic. Widespread customer-level data would also allow us to comment in more detail on how the pandemic response in different

Fig. 8. As in Fig. 7, but for residential (red lines) and commercial (blue lines) electricity sales.
regions of the U.S. resulted in changes to electricity consumption. While a handful of region-specific, grid-scale hourly load forecasting models are emerging that focus on isolating residential and non-residential hourly loads (e.g., [33,34]), more widespread analyses of the type presented here are needed to inform system operators and utilities for long-term resource planning.

In terms of the long-term implications of our work, we showed that, in agreement with previous work, residential electricity demand increased throughout most of 2020 across multiple spatiotemporal scales. A higher proportion of people teleworking indefinitely suggests that this trend should persist, although the magnitude is dependent on factors that are highly uncertain. A shift toward a higher residential portion of the total load could make residential rooftop solar slightly more favorable. It may be that people have more incentive to invest in solar panels to lower their individual bills when they spend a higher fraction of their time at home. Additionally, a midday increase in residential loads can increase the rates of self-consumption for PV-generated power rather than exporting it to the grid. This may reduce challenges in integrating residential solar power. Time-of-use pricing programs will also be impacted by higher residential loads during the daytime. With people staying home during the day there will almost certainly be fewer households making temperature setbacks during the day which should drive increases in residential cooling and heating demands. Widespread electrification of residential heating should make changes in residential consumption and load profiles more important to driving variations in total load. The findings also expose the data needed to isolate customer classes to evaluate heterogeneity in customer adaptations to extreme weather events and the effectiveness of time-of-use pricing programs.

Multiple grid regions saw a sharp spike in their day-ahead forecast error when COVID-19-induced shutdowns started in March and April of 2020. These errors are due to fundamental shifts in the ways in which we consume electricity. Such changes could have major implications for electricity operations planning. As one example, the shape of the pre-COVID residential weekday load profile in the ComEd service area closely follows that of California ISO’s “duck curve” [35]. Our analysis shows that the increased daytime loads under widespread teleworking could be expected to “flatten” the duck curve similar to the shift seen in the ComEd profile during shelter-in-place conditions in March and April of 2020. This flattened daily net load profile could lower ramping needs, reduce oversupply risks [36–38], and change market prices [39]. Such an impact on a duck curve load shape was observed during March and April 2020 in a small community in Austin, Texas with extensive solar penetration [40]. It should be pointed out that we did not observe these shifts at the BA scale. Better understanding these potential shifts is critical to inform and update load forecasting approaches that typically draw upon historical hourly load profiles for future electricity system planning and operations [41–43].

Finally, the observed and potential shifts in electricity load profiles documented in this paper also motivate new approaches to predicting long-term changes in total hourly loads that explicitly represent potential shifts in behaviors and economics [44]. While some changes to the way we work and live are likely to revert to pre-COVID-19 conditions, others like widespread teleworking may be permanent fixes of “the new normal.” This research demonstrates the potential for long-term changes like permanent teleworking to increase total weekday electricity loads during workday hours and to reduce the slope and magnitude of the morning and evening ramps. Our results suggest that the “new normal” may not be a singular permanent change in how people consume electricity, but rather an increase in the variability of electricity consumption patterns across sectors and scales.

CRediT authorship contribution statement

Casey D. Burleyson: Conceptualization, Data curation, Formal analysis, Writing – original draft, Visualization. Aowabin Rahman: Conceptualization, Formal analysis, Writing – review & editing. Jennie S. Rice: Conceptualization, Formal analysis, Writing – review & editing. Amanda D. Smith: Conceptualization, Formal analysis, Writing – review & editing. Nathalie Voisin: Conceptualization, Formal analysis, Writing – review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2021.117711.

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