LOCAL TEMPERATURE EFFECTS ON LOCATIONAL MARGINAL PRICES IN THE CALIFORNIA WHOLESALE ELECTRICITY MARKET

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Abstract

This paper quantifies the effect that local daily average temperatures have on the daily average locational marginal price (LMP) in California's wholesale electricity market. The LMP data is obtained from the California Independent System Operator (CAISO) for a period from October 2020 to October 2023. Weather station data is obtained from the National Oceanic and Atmospheric Administration (NOAA) for the same period. The LMP nodes are assigned weather station data using the Haversine Distance formula. The temperature effect is then estimated using a linear, quadratic, and binned two-way fixed effects regression controlling for both node and time fixed effects. The linear model indicates that a one degree increase in the local daily average temperature results in an increase of $0.85/MWh in the daily average locational marginal price. The quadratic model shows a decreasing marginal effect of temperature on price until approximately 68 degrees Fahrenheit, after which the marginal effect increases. The binned regression model was the most flexible showing that temperatures below 45 degrees Fahrenheit and above 80 degrees Fahrenheit had significantly greater locational marginal prices compared to when temperatures are between 65- and 75-degrees Fahrenheit. These results will have implications on the decision making within both the public and private sectors and influence the debate between nodal and zonal market structures.

Introduction

With global temperatures rising, largely due to human activity, it's important to understand the effects it will have on our lives. These rising temperatures will influence nearly every aspect of electricity from the method used to generate it, to how it flows through the grids and the way in which its consumed. When it comes the generation of electricity, for thermal power plants, when there is a rise in ambient air temperature, it can cause generation to be less efficient. This same degradation in efficiency can be seen within solar panels as well. Increases in temperature will also impact demand seen by the grid. This is because when it is hotter outside, more people are using air conditioning units to cool their homes causing the grid to see a higher level of load. With temperature also causing inefficiencies in power generation, there is a mismatch between supply and demand causing power outages. This is exactly what has been observed in the real world. These can lead to price effects that are seen by the consumer down the line.

Quantifying the effect local temperature has on the whole sale electricity market carries value in both the public and private sectors. Within the private sector, it'll allow for ISOs, and the smaller ancillary markets they serve, to better inform their policy making decisions. For the public sector it can inform their decision making in the short and long-term. It will also impact the system used for managing electricity markets around the world. Currently there are two systems used around the world for managing wholesale electricity markets, zonal and nodal pricing. The California ISO, and many other parts of the United States, utilize nodal pricing to manage their wholesale electricity markets while the entirety of the European Union and many of its neighboring countries, like the UK and Norway, utilize a zonal pricing structure to manage their markets.

This paper aims to quantify the effect of local daily average temperatures on the daily average locational marginal price (LMP) of electricity within the wholesale market of California. This is achieved through a linear, quadratic, and binned two-way fixed effects regression model. Both nodal and time fixed effects are included as both are believed to have effects on the LMP that are not captured within the regression equation. The model is estimated using weather station data from the National Oceanic and Atmospheric Administration (NOAA) and LMP data from the California Independent System Operator (CAISO). The nodes from CAISO are then assigned weather station data using the haversine distance equation. Due to there being significantly fewer stations than nodes, there are multiple nodes assigned the same weather station data. The shortest distance between a node and station is 0.17 kilometers and the furthest distance is 116.8 kilometers.

Prior literature has not quantified the exact effect of local temperatures on local electricity prices. Rather, they have sought to understand the effect of climate change on electricity expenditures (Véliza et al., 2017) or the impact of temperature forecasts on the day-ahead electricity market in Italy (Bigerna, 2018). This study is most related to the Bigerna (2018) study, however, where it differs is that it quantifies the effect of local temperatures on local electricity prices in a nodal market structure rather than the zonal market structure used in Italy.

The study finds that there is an economically and statistically significant quadratic relationship between local daily average temperatures and daily average locational marginal prices. When the local daily average temperature is at 80 degrees Fahrenheit, a one degree increase in temperature results in an increase of $1.34/MWh in daily average locational marginal price. This effect increases when local daily average temperature is 100 degrees Fahrenheit where a one degree increase in temperature results in an increase of $3.41/MWh in the daily average locational marginal price. The binned regression model additionally finds that when local daily average temperatures are lower than 45 degrees Fahrenheit, the daily average locational marginal price is $45.32/MWh greater than when temperatures are between 65- and 70-degrees Fahrenheit. When temperatures are above 80 degrees Fahrenheit, daily average locational marginal prices are $21.54/MWh greater than when temperatures are between 65- and 70-degrees Fahrenheit.

Electricity and Temperature Pricing

As previously mentioned, nodal market structures are predominantly utilized in many parts of the United States, including California. It works by placing thousands of nodes throughout a managed region. The wholesale electricity prices, the locational marginal price, seen at each of these nodes then varies depending on factors like the system wide marginal cost of energy, the marginal cost of congestion, and the marginal cost of losses. This means that the locational marginal price can vary across different regions of a managed area. For example, the price seen in San Francisco will be different from prices seen in Los Angeles. The prices may also vary between closer cities like San Francisco and San Jose. Zonal pricing on the other hand splits a managed area into different "zones" with the number of zones varying between country or region. For example, Italy is split into six different zones while Germany is split into 4. An overall electricity price is then set for each of these zones.

Quantifying how temperature increases electricity prices may influence countries currently using a zonal pricing structure to make the switch to a nodal structure as it allows for the price of electricity to differ for different areas. Additionally, it can allow for the public sector to understand where infrastructure is needed most and make informed planning decisions for generation and transmission needs. Within in the private sector, it would allow for companies and other entities to make better informed decisions when planning in the short and long-terms. In the short-term, they will be able to make better operational decisions for when they should operate their equipment and at which facilities. In the long-term, it'll allow for them to make informed investment decisions about where they should site new facilities to incur lower energy costs. The same applies for investments in generation facilities through which they may be able to capture greater profits through increased energy prices.

Temperature affects nearly all aspects of electrical grids. It not only affects the power generation sources used, but also the way in which electricity is transmitted across the grid. This is due to how electrons behave. The speed at which they can travel is tied directly to temperature. When temperatures rise, there will be a greater resistance in the circuit causing electrons to move slower. The same effect is seen when temperatures are lower causing a lower resistance making it easier for the electrons to move through a circuit.

Temperature will also affect how electricity is consumed. When temperatures are higher, more people are likely to be using air conditioning units to cool themselves down. When they are lower, people are more likely to be using their heating systems. This in turn will impact the other aspects of the grid mentioned. If temperatures are higher, it means more people will be using air conditioning systems which in turn leads to a greater load on the grid. This demand will lead to more power needing to be generated, which becomes less efficient with higher temperatures. This means more power needs to be transmitted through the grids, leading to greater congestion due to the impact temperature has on the resistance of transmission lines.

These will all influence the locational marginal price of electricity. Currently there are regions in the United States that are managed by Independent System Operators (ISO).

California is one such a region. Their electricity market is set by the California Independent System Operator (CAISO). CAISO uses LMP as a way of pricing electricity in their managed wholesale markets. The reason temperature will influence these prices is due to the locational marginal price being made up of three components: the marginal energy cost (MEC), the marginal cost of congestion (MCC), and the marginal cost of loss (MCL). The MEC is first set by the ISO for the entire region. MCC and MCL both change depending on demand in the market. Higher temperatures will have some effect on all three aspects of the LMP: the MCE can be set higher if more costly generation methods need to be employed to meet the demand and offset the inefficacies; The MCC will be greater due to higher demand and the increased temperature lowering the efficiency of the transmission lines; Finally, the MCL will be higher due to greater losses from the lowered efficiency of transmission lines.

Literature Review

The research conducted in this paper relates to broader literature on the impacts of climate change and electricity markets, both on the demand and supply sides (Bigerna, 2018; Hill et al., 2021; Véliza et al., 2017). Much of the research done in this field has related to using models to project future demand and prices and understanding the impacts of climate change on interregional power systems. This literature has found that future temperature increases, and more frequent extreme weather events will have far reaching impacts on not only the demand and supply side of regional electricity markets but will also have an interregional impact.

A related study by Véliza et al. (2017) sought to quantify and understand what the effects of climate change were on electricity expenditures in the state of Massachusetts. Like this study, they choose that state due to the independent system operators use of locational marginal prices within its market. They first found that the load duration curve indicates that warmer summer temperatures raise summer-time consumption by about 15% and winter-time consumption declines by about 6%. This is consistent with the results described by Auffhammer et al. (2017). Their statistical results additionally indicated that electricity prices increase non-linearly with consumption. They then created a model to predict the effect a 2-degree Celsius increase in global mean temperatures will have on the price of and consumption of electricity. They found that the average households' annual expenditures on electricity will increase by about 12% and commercial customers will increase by 9%. These increases are largely caused by higher prices for electricity. This paper will differ from Véliza et al. (2017) by quantifying the effect of local temperatures on local prices.

The two most closely related papers to research conduct this one come from Hill et al. (2021) and Bigerna (2018). Hill et al. (2021) examines the impacts of long-term shifts in water availability and higher average temperatures on the both the supply and demand sides of the electricity market on the west coast of the US. It also examines how the interactions between the regions of California and the Pacific Northwest could be impacted. Unlike this study, their study is focused more on examining the impact hydroclimate changes will have on electricity markets in both regions and on their interregional interactions. To do this, they first simulated power system operations across the West Coast using the CAPOW model from Su et. al, 2020. To isolate any potential effects of climate change on the power system outcomes, they held generation capacity constant at the 2016 level and only consider changes to long-term demand caused by climate change. For the metrological and streamflow data, they collected observed air temperature and wind speed data for 17 weather stations in the Global Historical Climatological Network and collected solar irradiance data for six sites from the National Renewable Energy Laboratory's National Solar Radiation Database. Simulated data for all three variables were then acquired for both a hindcast period from 1970 to 2000 and a forecast period from 2030 to 2060 from a downscaled global climate model output that consisted of two representative concentration pathways (RCP) by ten global climate models (GCM). The simulated temperature and wind speed were bias corrected to match statistical properties of the observed weather station data over their observational period. A similar process was utilized for streamflow data. This resulted in 80 GCM-RCP-hydrologic model configurations. Due to the time it took to simulate a single year, they decided to select a subset of 11 model configurations. Prior to selection of the subset, they calculated daily adjusted demand in the Mid-Columbia and CAISO markets for their forecast period by subtracting any available hydropower, solar, and/or wind power generation from the simulated daily electricity demand. The two key performance metrics used to evaluate grid performance was reliability and wholesale electricity prices. Their study found that future excessive heat in California could exert a strong effect on prices and reliability in the Pacific Northwest. I extend their study by looking deeper at the local effects of temperature on the local wholesale electricity prices only in California.

A study done by Bigerna (2018) relates much closer to this paper's as it also provides empirical evidence for weather effects on the electricity markets in Italy. Similar to this paper, they conduct their analysis at a more granular level than previous studies by looking at the hourly effects of temperature on electricity price. Where the study in this paper differs is that they attempt to assess the impact of the temperature forecasts on the electricity day-ahead market prices rather than assessing the affect local daily average temperature has on local daily average locational marginal prices. Additionally, the nature of the Italian electricity market differs fundamentally from the California market. Italy uses a zonal pricing market splitting the country into six regions as opposed to the Californian nodal pricing market. The general model specification Bigerna utilizes is a simple supply equation that relates price as a function of quantity, a possible market structure, and temperature with an error term. They then create three, both parametric and non-parametric, specifications of the model to assess the impact temperature has on day-ahead electricity prices in the six regions of the Italian market. The first is a non-parametric regression to compute a kernel estimator of the relation price-quantity and price. The second is a simple ARMA(p,q) used for each regions price. The third model is a VAR(p) model specified for the six regional prices with exogenous variables X. Bigerna also considers three different temperature forecasting behaviors in the electricity market: short-term memory; long-term memory with perfect foresight; and long-term memory with a specific alert mechanism for extreme weather conditions. Bigerna utilized hourly temperature data from the Italian Military Airforce General Office for Meteorology collected at six airports located in the center of the six regions. They find that temperature does have a significant explanatory power for prices along with the traditional load and structural variables. They also find the marginal effect is on average in the order of one percentage point with it being higher for cooling-degree hours and lower for heating-degree hours. Additionally, they find the out of sample forecasting performance of their model to be satisfactory.

Data

The daily average weather data comes from the National Oceanic and Atmospheric Agency's (NOAA) Global Surface Summary of the Day (GSOD) dataset. The data includes variables such as mean daily temperature, dew point, and precipitation among others. This information is collected at the weather station level across the United States. For the purposes of this study, weather station data for the state of California will be used from October 2020 to October 2023.

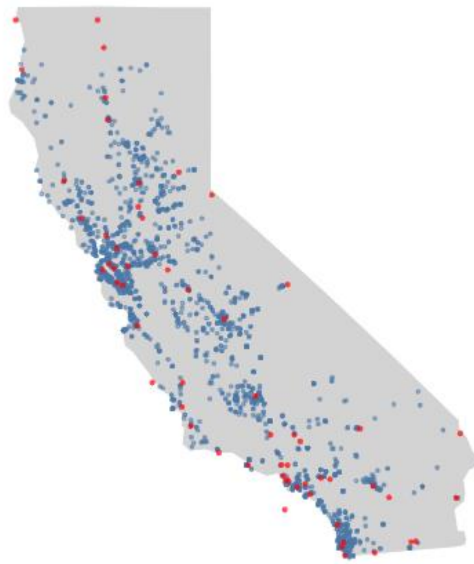
The daily average LMP data comes from the California Independent System Operator (CAISO) and covers a period from October 1, 2020 to October 31, 2023. This is due to the limitation of CAISO data only being available up to past three years. The original format of the data is hourly LMP for each node split into fifteen-minute intervals. That data is then collapsed into a daily average. This was mainly done as it became clear early on that using the fifteen-minute interval data would've been too large to work with. For the purposes of this study, it will be sufficient to instead use daily average LMP. While there may be other interesting effects from using an hourly-level analysis, its likely hourly temperatures and prices are highly correlated and using a daily analysis captures the bulk of the story about the local temperature-price relationship. Additionally, the weather station data from NOAA comes in the form of daily data and acquiring hourly data would be challenging. A single observation in the data is a single node for one day with its average LMP in price per megawatt hour (MWh) and local day temperature at the node. There are 1,581 nodes included in the study.

Since the purpose of this study is to quantify the effect that local daily average temperature has on daily average locational marginal price, weather station data from each of the NOAA stations must be assigned to each of the CAISO nodes. This will be done by using the haversine distance between the node and the weather station. The haversine, also known as the great circle, distance is a formula used to calculate the angular distance between two points on the surface of a sphere, in this case the Earth. The mathematical equation is shown below:

$$distance = 2r\ arcsine(\sqrt{\sin^2\left(\frac{\varphi_2 - \varphi_1}{2}\right) + \cos\varphi_1 \cdot \cos\varphi_2 \cdot \sin^2\left(\frac{\omega_2 - \omega_1}{2}\right)}$$

Where φ_1,φ_2 are the latitude of the node and the station in radian form and ω_1,ω_2 are the longitude of the node and the station in radian form. Using the formula, the distance between the first node is calculated with each of the weather stations. The station with the shortest calculated distance is then assigned to that node. This process is then repeated for each of the nodes. Figure 1 shows a map of California with the locations of LMP nodes plotted in blue and the locations of NOAA weather stations plotted in red.

Figure 1: Map of LMP nodes (Blue) and NOAA weather stations (Red) in California



Since there are significantly more nodes than there are weather stations, it means that a single station's data will be assigned to multiple nodes.

Table 1 – Summary Statistics of Key Variables

	Min	Mean	Max	Std Dev.
LMP ($/MWh)	-370.085	65.40495	916.2955	54.96334
Temperature (Fahrenheit)	8.4	62.10568	109.2	12.86393
Distance (Kilometers)	0.1709343	27.15102	116.8269	21.17728
Dew Point (Fahrenheit)	-9.3	44.06842	76.1	10.29159
Precipitation (Inches)	0	0.0389791	5.64	0.1983256

Table 1 shows the summary statistics for locational marginal price, temperature, node distance from NOAA station, dew point, and precipitation over the study's three-year timespan. The average LMP seen across all nodes in the study was $65.40/MWh. The minimum price seen was -$370.09/MWh and the maximum price seen was $916.30/MWh. Both the minimum and maximum prices are unsurprising. When supply is high and demand is low, there is more electricity demand than load. The resulting negative prices is a market signal that electricity generation needs to be reduced to match load. The maximum price is also unsurprising as it represents other market shocks to the wholesale market that are not necessarily limited to California. According to Federal Reserve Economic Data (FRED), February 2021 saw a spike in the Henry Hub natural gas spot price due to Texas' historical winter storm. Natural gas prices spiked again in the Summer of 2022. The average temperature over the three-year timespan was 62.11 degrees Fahrenheit with a minimum of 8.4 degrees Fahrenheit and a maximum of 109.2 degrees Fahrenheit. The average distance a node was located from a NOAA weather station was 27.15 kilometers with a minimum distance of 0.17 kilometers and a maximum of 116.83 kilometers. This maximum was expected as there are areas with only a single weather station as seen in Figure 1. The average dew point seen across the three years was 44.07 degrees Fahrenheit with a minimum of -9.3 degrees Fahrenheit and a maximum of 76.1 degrees Fahrenheit. The average precipitation across the three years was 0.039 inches with a minimum of 0 inches and a maximum of 5.64 inches.

Figure 2 – Average LMP over Study Timespan

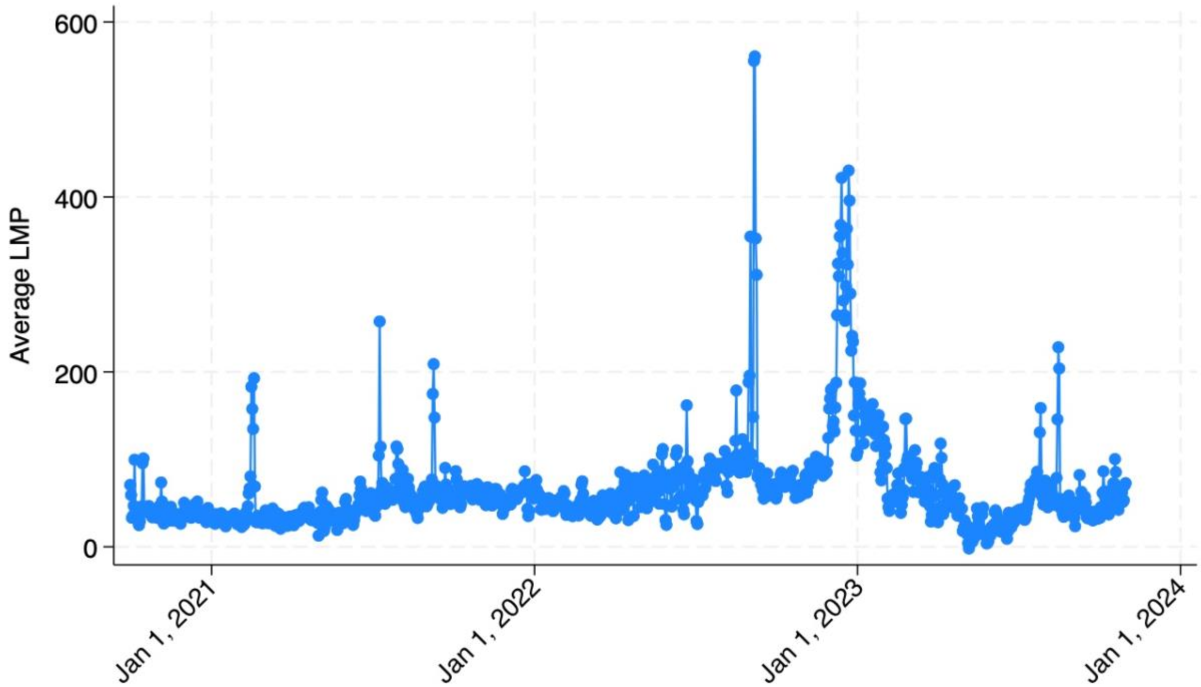


Figure 2 shows the average LMP across all nodes in California over the course of the study. As discussed above, there were numerous spikes to the price due to different factors, including record high temperatures in the summer of 2023 and natural gas price spikes.

Figure 3 – Average Temperature over Study Timespan

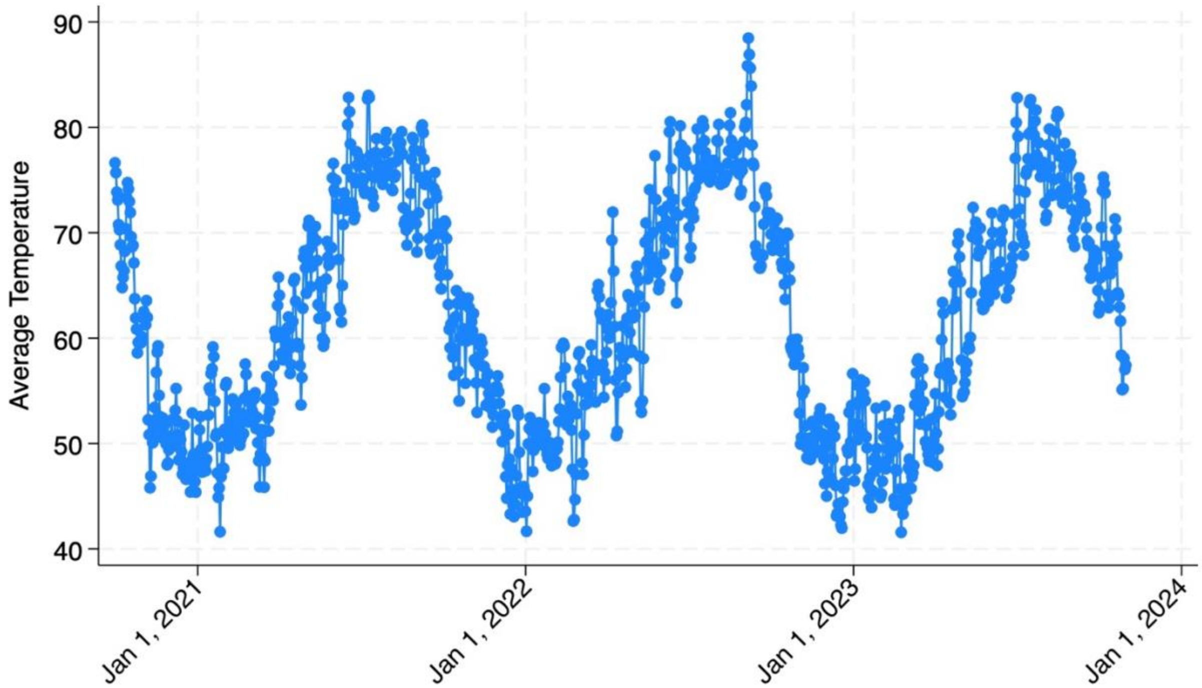


Figure 3 shows the average temperature across all nodes during the study's three-year timespan. The figure shows what was generally expected, temperatures rising during the spring and summer months and falling during the fall and winter months. However, something that is especially interesting is the sudden jump in average temperature during the 2023 summer. This was due to California seeing extreme heat. According to the California Governor's Office of Emergency Services, between July 1 and July 28, 2023, 117 highest max temperature records were tied, and 241 records were broken. This also coincides with Death Valley, California recording the sixth hottest measured temperature in world history on July 16, 2023.

Empirical Methodology:

This study employs both a linear fixed effects model, equation (1), and a quadratic fixed effects model, equation (2). For both models, daily average locational marginal price is regressed on local daily average temperature with both year-by-month and node fixed effects. The quadratic model is estimated as it's believed that the extremes in temperature on both ends will likely have a significant impact on the locational marginal price of electricity.

$$LMP_{it} = \alpha + \beta_1 T_{it} + \gamma_i + \delta_t + \varepsilon_{it} \tag{1}$$

$$LMP_{it} = \alpha + \beta_1 x_{it} + \beta_2 T_{it}^2 + \gamma_i + \delta_t + \varepsilon_{it} \tag{2}$$

LMP_{it} is the locational marginal price on day t for node i, T_{it} is the temperature on day t for node i, γ_i and δ_t are the nodal and year-by-month time fixed effects respectively, and finally ε_{it} is the error term. Equation (3) below represents the binned regression model.

$$LMP_{it} = \sum_k \theta_k D_{kit} + \gamma_i + \delta_t + \varepsilon_{it} \tag{3}$$

D_{kit} is an indicator variable equaling 1 if T_{it} is in the kth bin of temperatures. θ_k is the coefficient of interest for the kth bin of temperatures. While a quadratic regression may more accurately represent the data by accounting for the extremes in temperature on both ends, the data may not be a perfect parabola. The binned regression allows for the model to fit the data more flexibly than forcing it to take a perfect shape. Again, γ_i and δ_t represent the nodal and year-by-month time fixed effects. Standard errors for all three equations are clustered at the nodal level to account for serial correlation within nodes.

The nodal and time-fixed effects allow for the model to account for any unobservable effects that cannot be directly included. Including nodal fixed effects into the model allow for the variation in node prices to be compared to only themselves rather than being compared to other nodes, allowing for a better quantification of the local effect of temperature on price. Nodes located in different areas may see different demand at different times. Take for example a node located in Los Angeles or San Francisco compared to a node located in Barstow. The demand seen in a major population center will be fundamentally different from the demand seen in a smaller town. Additionally, a node located in northern California near the border with Oregon will see different demand during different months than a node located in the Mojave Desert during the same times. Including the fixed effects allows for the nodes to essentially be compared on equal footing and account for those effects not included in the model. Time-fixed effects are included for similar reasons. It allows for the variations in price to be compared within each month. This is due to the fact there may be other variables affecting price in each month than just the temperatures seen during that month. Take for example February of 2021 where there was a significant increase in the LMP. During the same time, Texas experienced a historical winter storm that caused natural gas prices to increase significantly. The effects of those increased prices were not contained to just Texas, but also seen across the country. Additionally, since both prices and temperatures have been rising over time, due to factors like inflation and climate change, that rise between both may be falsely correlated. The inclusion of nodal and time fixed effects will allow for those fundamental differences to be accounted for. Since the focus of this study is to quantify the local effect of temperature on local prices and not on finding the difference in price effects by region or time, the fixed effects allow the study to reach its objective.

Results

Table 2 below displays results from equation (1) and (2) with clustering of standard errors at the nodal level.

Table 2: Results of Linear and Quadratic Regressions on LMP

	Locational Marginal Price ($/MWh)	Locational Marginal Price ($/MWh)	Locational Marginal Price ($/MWh)	Locational Marginal Price ($/MWh)	Locational Marginal Price ($/MWh)
Temperature	-0.068*** (0.0054152)	0.8451365*** (0.0118044)	-8.577463*** (0.2695006)	-5.303363*** (0.1982965)	-6.932126*** (0.2337574)
Temperature Squared			0.0656447*** (0.0020519)	0.0462501*** (0.0015058)	0.0516992*** (0.0017612)
Average Temperature					2.351879*** (0.0301102)
Dew Point					-0.4668581*** (0.0089399)
Precipitation					-5.2536*** (0.3977377)
Node FEs	N	Y	N	Y	Y
Time FEs	N	Y	N	Y	Y

R-Squared	0.0003	0.5461	0.0646	0.5580	0.5738
Observations	1,753,484	1,753,484	1,753,484	1,753,484	1,753,484

Notes: Columns 1 and 2 estimate equation (1). Columns 3 and 4 estimate equation (2). Column 5 estimates equation (2) with the addition of controls for daily average temperature across California, dew point, and precipitation. Standard errors in parenthesis are clustered at the nodal level. *p-value<0.1 **p-value<0.05 ***p-value<0.01

Equation (1) is first estimated in column 1 without node and time fixed effects. The results indicate there is a negative relationship between temperature and price, showing that a one-degree Fahrenheit increase in local daily average temperature results in a decrease of $0.068/MWh in daily average locational marginal price. This goes against what intuition would say about the relationship between temperatures and price and what prior literature has found. The model has an r-squared value of 0.0003 indicating it does explain much of the variation in prices.

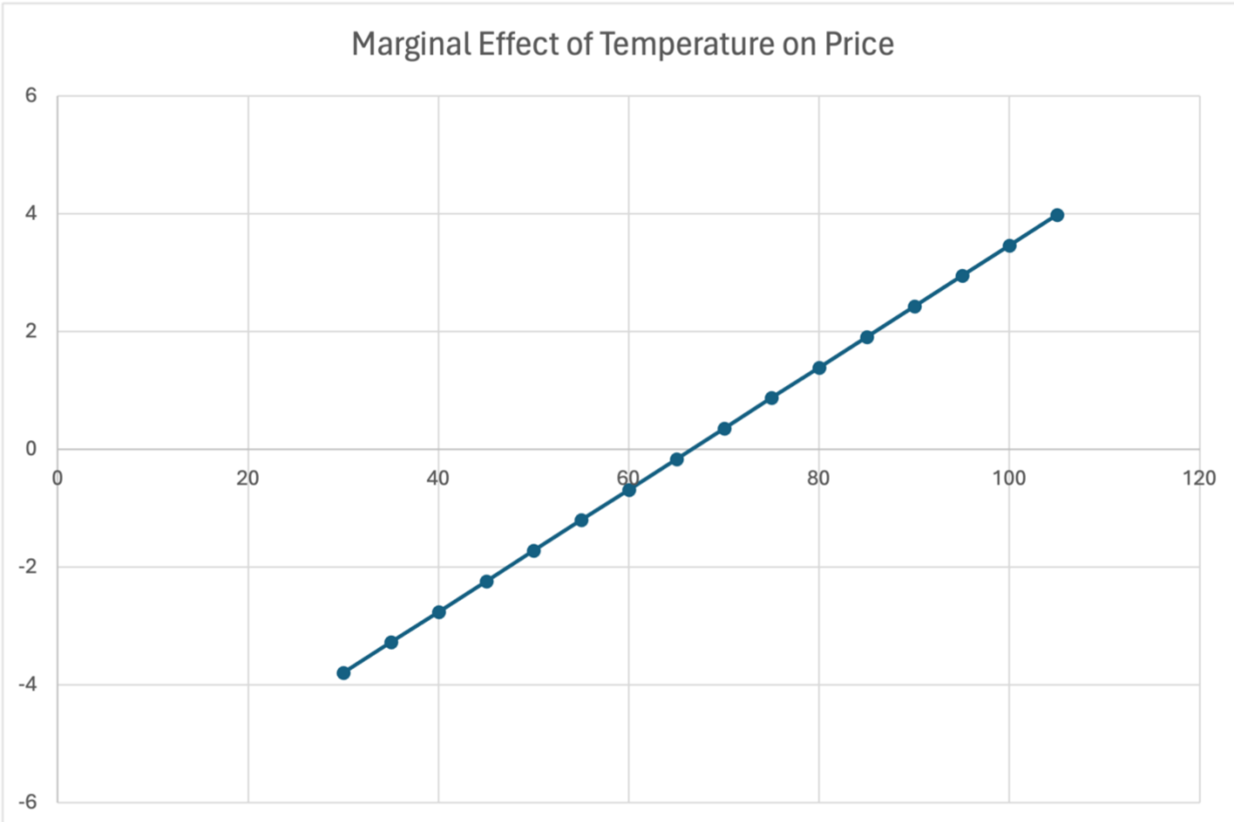
Column 2 estimates equation (1) with node and time fixed effects. The result is more in line with intuition and prior literature showing that a one-degree Fahrenheit increase in local daily average temperature increases the daily average locational marginal price by $0.85/MWh. The estimation has an r-squared value of 0.5461 indicating that the inclusion of node and time fixed effects substantially increases the share of price variation explained by the model. Both estimates from columns 1 and 2 are statistically significant at the 1% level.

Column 3 estimates equation (2) not controlling for node and time fixed effects. The coefficients on temperature and temperature-squared are both statistically significant at the 1% level. The marginal effect of local daily average temperature indicates that at approximately 65 degrees Fahrenheit, a one-degree increase in temperature has no effect on the locational marginal price. The marginal effect of local daily average temperature at 80 degrees Fahrenheit shows that a one degree increase in temperature results in an increase of $1.93/MWh in the daily average locational marginal price by. At 100 degrees Fahrenheit, a one degree increase in the local daily average temperature results in an increase of $4.55/MWh in the daily average locational marginal price. The estimated equation has an r-squared value of 0.0646, indicating a larger share of the variation in price is explained by this model compared to the linear regression model with no fixed effects. However, the linear model with the inclusion of fixed effects still explains a significantly larger share of the price variation.

Column 4 estimates equation (2) with the node and time fixed effects. Both coefficients are again statistically significant at the 1% level but with an increase in the magnitude on the temperature coefficient and a decrease in the magnitude on the temperature squared coefficient. At approximately 58 degrees Fahrenheit, there is little to no effect on the daily average locational marginal price when local daily average temperature increases by one degree. This is lower than what was seen in the quadratic model with no fixed effects. The marginal effect shows that at 80 degrees Fahrenheit, a one degree increase in the local daily average temperature increases the daily average locational marginal price by \$2.10/MWh. At 100 degrees Fahrenheit, for an additional one degree increase in in local daily average temperature, there is an increase of \$3.95/MWh in the daily average locational marginal price. While the quadratic model with fixed effects saw a slightly larger marginal effect at 80 degrees Fahrenheit, the effect at 100 degrees Fahrenheit was significantly smaller with the difference being \$0.60/MWh. This model has an r-squared value of 0.5580, indicating it explains a larger share of the variation in price compared to the other three models. Intuitively this makes sense as a quadratic model would be able to better account for the extremes in temperature. Additionally, the inclusion of the node and time fixed effects lead to better estimates as they allow for any unobservables not included in the model to be controlled for. The marginal effect in the quadratic model is only equal to the effect in the linear model at approximately 65 degrees Fahrenheit. Below and above 65 degrees Fahrenheit, the effects are substantially different as indicated earlier.

Figure 4 shows a graphical representation of the marginal effect of local daily average temperature on the locational marginal price estimated in Column 5. This model adds controls for the daily average temperature across California, dew point, and precipitation.

Figure 4 – Marginal Effect of Temperature on LMP



When controlling for those variables, the magnitude on the Temperature coefficient decreases while the magnitude on the temperature squared coefficient increases. All included variables were statistically significant at the 1% level. At approximately 68 degrees Fahrenheit, there is no marginal effect of local daily average temperature on the daily average locational marginal price. At 80 degrees Fahrenheit, the marginal effect shows that for a one degree increase in the local daily average temperature there is an increase of \$1.34/MWh in the daily average locational marginal price. The marginal effect at 100 degrees Fahrenheit indicates that when local daily average temperature increases by one degree Fahrenheit, the daily average locational marginal price increases by \$3.41/MWh. Both effects were lower than the quadratic model with no fixed effects and the model with fixed effects. This is due to the inclusion of the average temperature, precipitation, and dew point variables. Daily average temperature across California was included as it allows for a better estimation of the local effect of temperature on local prices. Temperatures are likely to be correlated across nodes, when temperatures are higher in one area, it's likely temperatures are higher in nearby areas as well. This would lead to an increase in system-wide energy cost for all nodes as more expensive generators may need to be turned on. Controlling for the average temperature across the state allows for the isolation of the local effect of temperatures on local prices. The effect that column 5 shows can be thought of in the following way: Imagine two otherwise identical days for two similar nodes, for the same month and year, and for the same California average temperature, how much higher is the locational marginal price on the locally hotter day? This is a key difference between column 5 and columns 1-4. Even with the inclusion of this variable, local daily average temperatures still have a substantial effect on local prices. The model shows that for a one-degree Fahrenheit increase in the average temperature across California, daily average locational marginal price increases by $2.35/MWh. Precipitation was included as generally, when it is raining, temperatures feel cooler resulting in less load on the grid due to use of cooling units decreasing the locational marginal price. Dew point was included as a proxy for humidity levels. Both coefficients have a negative impact on the locational marginal price with the coefficient on dew point having a larger magnitude. The r-squared value is 0.5738 indicating the largest share of variation in price is explained by the model.

Table 3 displays the results of equation (3) where temperatures are placed into bins. The equation is estimated using node and time fixed effects as it was shown in the previous two equations that its inclusion has a significant impact on the estimated effect of local daily average temperature on the daily average locational marginal price.

Table 3: Results of Binned Regression on LMP

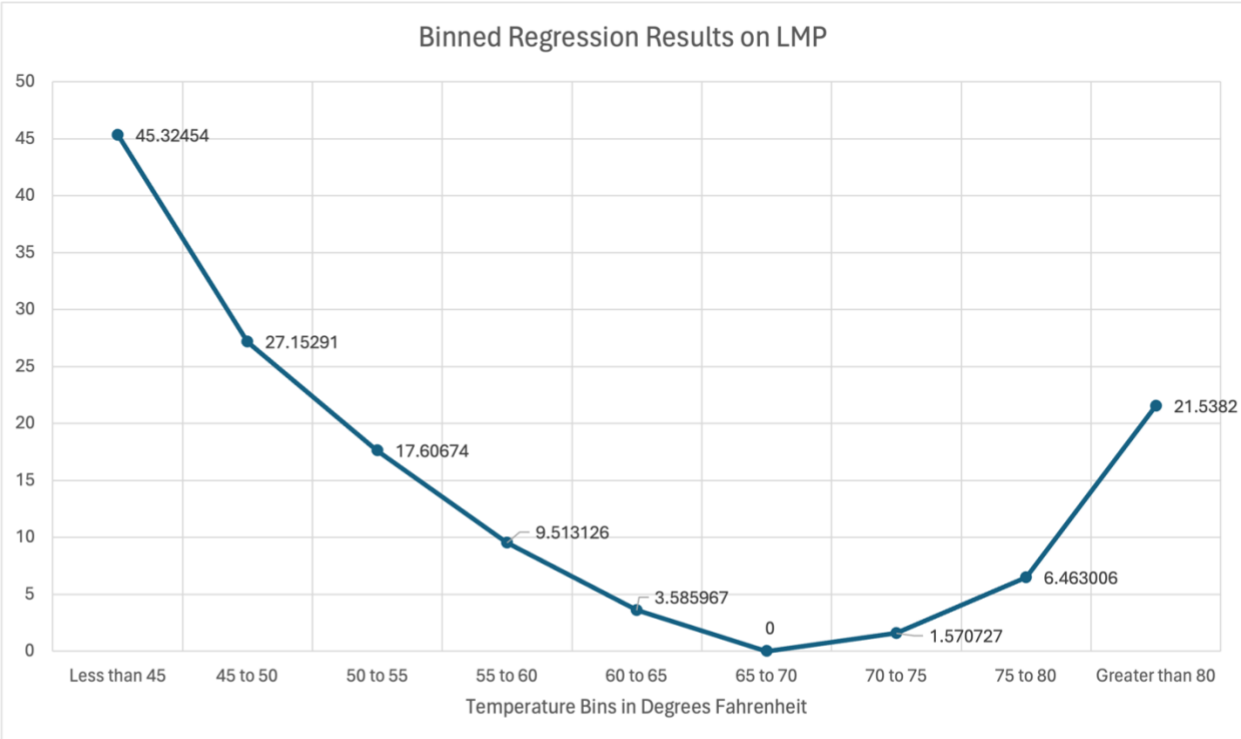
	Locational Marginal Price ($/MWh)
Temperatures Less than 45	45.32454*** (0.8899943)
Temperatures Between 45 and 50	27.15291*** (0.4886347)
Temperatures Between 50 and 55	17.60674*** (0.3453875)
Temperatures Between 55 and 60	9.513126*** (0.2481162)

Temperatures Between 60 and 65	3.585967*** (0.1386143)
Temperatures Between 70 and 75	1.570727*** (0.1775529)
Temperatures Between 75 and 80	6.463006*** (0.3348547)
Temperatures Greater than 80	21.5382*** (0.6561302)
Average Temperature	2.336212*** (0.0189425)
Node FEs	Y
Time FEs	Y
R-Squared	0.5811
N	1,753,484

Notes: The regression estimates equation (3) with a control for average temperature. Standard errors in parenthesis are clustered at the nodal level. *p-value<0.1 **p-value<0.05 ***p-value<0.01

Equation (3) is a way to expand on the quadratic fixed effects model from equation (2). While that model was able to explain a significant amount of the variation in price by accounting for the extremes in temperature, it was not the most flexible way to do so. In this model, temperatures were binned into nine categories of five-degree increments. Due to these bins representing indicator variables, the 65-to70 degree temperature bin was omitted to prevent collinearity and serve as the comparison bin. The coefficients on each of the other bins represents how much larger the daily average locational marginal price is for local daily average temperatures in that bin compared to the 65-to-70-degree bin. Figure 5 below shows a graphical representation of the binned regression results.

Figure 5 – Regression Results from Equation 3



When temperatures are below 45 degrees Fahrenheit, the locational marginal price is approximately $45.32/MWh greater than the comparison bin, when temperatures are between 65- and 75-degrees Fahrenheit. This difference in locational marginal price falls as temperatures rises closer to the comparison bin. At 60-to-65 degrees Fahrenheit, the difference is only $3.59/MWh. As temperatures increase past the comparison bin, the difference in their prices begins to increase. Between 70 and 75 degrees, the difference is $1.57/MWh. Between 75 and 80 degrees, the difference is $6.46/MWh. Lastly, when temperatures are greater than 80 degrees, daily average locational marginal prices are $21.54/MWh greater than when local daily average temperatures are between 65- and 70-degrees Fahrenheit. The model has an r-squared value of 0.5811.

Discussion

These results show a clear quadratic relationship between the local temperatures and local electricity prices in California. This relationship will have implications within both the private and public sectors. The private sector will be able use this understanding of the relationship to drive better decision making in the short- and long-terms. In the short-term, it allows for companies to better plan the day-to-day operations of their facilities, such as manufacturing plants. This will be driven by understanding that the lowest average locational marginal price is achieved when temperatures are between 65- and 70-degrees Fahrenheit. By using weather forecasts, they can understand when they will incur the greatest energy costs for their facilities, allowing for greater operational and financial planning. In the long-term, it can allow for them to make better siting decisions for new facilities. Understanding that local daily average temperatures between 65- and 70-degrees Fahrenheit incur lower daily average locational marginal prices compared to when temperatures are higher and lower will lead to the decision being made to site new facilities in areas of California with daily average temperatures between 65- and 70-degrees Fahrenheit. This will allow for facilities to incur the lowest energy costs allowing for the firm to extract greater profits. For firms building generation facilities, they may choose instead to site new facilities in areas with greater or lower average temperatures to gain from the increased energy costs associated with those temperatures increasing their profits.

Within the public-sector, knowing this relationship between local temperatures and local prices will allow for more informed decision making for policymakers and regulators. Understanding that temperatures between 65- and 70-degrees Fahrenheit see the lowest energy costs will allow them to gain a better understanding of the electricity market and why some areas are seeing greater costs than others. An example of policies lawmakers may choose to pursue are those that enable efforts to decrease daily average temperatures observed in areas with higher energy costs to get closer to that 65-to-70-degree range to decrease the energy costs of consumers and producers. It also carries impacts in the debate between nodal and zonal market structures. For markets operating under a zonal structure, if there are areas within that zone that see average temperatures between 65 and 70 degrees Fahrenheit while other areas see higher or lower average temperatures, it can be a signal that a uniform price for the whole zone is not adequate. There will be consumers paying higher prices than they otherwise would be while other consumers are paying lower prices than they otherwise would be. In this case, regulators may choose to switch to the nodal market structure to better reflect the prices that consumers should be seeing within these areas.

Extensions

This study acts a baseline for research into local temperature effects on local prices with multiple avenues for additional research. One such extension would be to examine the heterogenous effects of temperature on price. This study only quantifies the average effect of local temperatures on local prices across all nodes. However, one could imagine that the local effect may vary depending on the individual aspects and characteristics of the nodes. These aspects include the generator type and capacity at the node, transmission capacities at the node, and congestion seen at the node. Examining these drivers of heterogeneity on the responsiveness of price to temperature would be a worthwhile endeavor and lead to a better understanding of the local temperature-price relationship. An additional avenue is the extension of the model to other independent system operators in the United States such as the Energy Reliability Council of Texas (ERCOT) and the Midcontinent Independent System Operator (MISO). These regions may see a different relationship between local temperatures and local prices for a variety of reasons such as geography, climate, generator capacities by type, and grid transmission capacities. Additionally, both ERCOT and MISO observe their own extreme weather events that have previously impacted their energy prices such as Texas' historic winter storm in February 2021. Lastly, combining the results of this study with climate project models to generate forecasts for future effects of local temperatures on local prices may lead to a better understanding of the future relationship between local temperatures and local prices and how it might change.

Conclusion

This study aimed to quantify the effect local daily average temperatures have on daily average locational marginal prices within the wholesale electricity market in California. Using pricing data from CAISO from October 2020 to October 2023 and weather station data from NOAA for the same period, we conclude there is a significant effect of local daily average temperatures on the daily average locational marginal price in the form of a quadratic relationship. When local daily average temperature is 80 degrees Fahrenheit, the marginal effect of a one degree increase in temperature is an increase of $1.34/MWh in the daily average locational marginal price. This effect rises when local daily average temperature is 100 degrees

Fahrenheit, where for a one degree increase in temperature, daily average locational marginal price increases by \$3.41/MWh. The binned regression model showed that when local daily average temperatures are below 45 degrees Fahrenheit, the daily average locational marginal price is \$45.32/MWh greater than when temperatures are between 65- and 70-degrees Fahrenheit. When local daily average temperatures are greater than 80 degrees Fahrenheit, the daily average locational marginal price is \$21.54/MWh greater than when temperatures are between 65- and 70-degrees Fahrenheit. These results continued to be both economically and statistically significant when controlling for daily average California temperature, node fixed effects, and year-by-month fixed effects.

While it has been intuitively understood that higher temperatures lead to higher electricity prices, this study quantifies that effect at the local level within a nodal market structure. These results will have impacts for both the private and public sectors in their decision making and policy considerations. Further extensions to this study discussed above will lead to a better understanding of this local temperature-price relationship in California and other regions of the US and how the relationship may change in the future.

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