**How Distributed Energy Resources and Dynamic Pricing Interact to Modify Residential Electricity Loads**

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The undersigned, appointed by the dean of the Graduate School, have examined the thesis entitled

**How Distributed Energy Resources and Dynamic Pricing Interact to Modify Residential Electricity Loads**

presented by Justin Hohner,

a candidate for the degree of Master of Science,

and hereby certify that, in their opinion, it is worthy of acceptance.

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Table of Contents

## LIST OF FIGURES



## LIST OF TABLES

**Abstract**

In this paper, we develop a model to analyze the effects of different electricity pricing regimes on the consumption decisions of consumers with installed solar photovoltaic generation assets under different asset configurations. Specifically, we explore the impacts of pricing structures (static, time-of-use, and real-time pricing) and technology deployments (grid only, solar, solar+battery) on consumers and utilities.

Distributed energy resources (DERs) by including energy storage can resolve the issues of intermittency and timing differences currently addressed by net metering. Adding energy storage with solar panels allows consumers to be completely grid-independent. Grid independence drastically changes the relationship consumers have with the grid and grid services. Individuals can increase resilience and have greater control of their costs. It may also create an opportunity for utilities to leverage consumer investment in distributed generation and storage technologies to improve grid operations and service. Encouraging consumer participation in the generation and dispatch of energy could take advantage of consumers' distribution to reduce transmission and distribution investments and their associated fixed costs.

This paper uses an hour-by-hour bottom-up simulation to model residential electricity load. The estimated load is then reduced by the consumers' sensitivity to price changes in the hour. For scenarios including a battery, a peak shaving algorithm is used to shift demand from the highest demand times to the least demand times using a 24-hour forecast. A geographically diverse set of locations are selected for regional comparison. Location-relevant prices are used for real-time pricing to keep costs in line with local differences.

The results from the model will demonstrate the potential effects of alternate pricing structures on both consumers and utilities. Understanding the different outcomes is important for evaluating alternative regulatory frameworks for establishing different pricing structures.

## Introduction

Distributed energy resources (DER) have the potential to change the business model of utilities. Allowing residential DERs to participate in electricity markets could transform customers from consumers to prosumers, who produce more than they consume. Grid operators may benefit from the distributed generation assets while providing a greater incentive and return on investment for consumers than net metering. Net metering and other incentive programs have successfully encouraged the adoption of DER but include limits that encourage right-sizing DER installations. By limiting the size of the system or profitability of the investment, net metering may reduce the risk the utility is exposed to and limit the benefits of consumer investments.

Net metering policy creates an obligation for utilities. Increasing levels of DER adoption could cause those obligations to be highly detrimental to utilities. By exposing consumers to more market price volatility shifts some of the risks to consumers. For loads that can be curtailed, greater price volatility benefits consumers by providing an opportunity to reduce bills when prices are high. In addition, providing the ability for consumers to sell and buy at market rates could create an incentive for consumers to invest further or increase the return on existing investments.

Net metering is an incentive program intended to increase consumer adoption of renewable generation technologies. Net metering offers an incentive to reduce the cost of installing and owning distributed generation and address the intermittency of renewable sources. Distributed generation (DG) technology like wind and solar cannot produce electricity on demand and requires storage. Customers are compensated for the electricity generated onsite and contributed to the grid to encourage the adoption of DG and charged for electricity consumed from the grid. Utilities can use credits to address the seasonal differences in generation capacity. Consumers are indifferent to when the electricity is generated and consumed through accounting techniques, reducing the need to also purchase batteries. How credits are managed affects the value captured by the consumer. Annual expiration of credits allows consumers to benefit in lower generation periods (winter) from the electricity generated during higher generation periods (summer) (Eid et al. 2014).

Consumers' benefits of net metering include lower bills, increase energy independence, and greater energy resilience. Excess generation is sold to the utility at a guaranteed rate, reducing the customer's electricity bill. Onsite electricity generation can cover most consumer electricity needs, reducing their dependence on the grid, increasing energy independence and resiliency. No transmission or distribution is needed. However, as an obligation for utilities, net metering is a loss or reduction in revenue and a shift in consumption patterns. Large-scale electricity storage is cost-prohibitive and geographically constrained, such as large water reservoirs for pumped storage. Without storage, electricity must be produced and consumed simultaneously, and the balance between supply and demand is maintained in part by the utility. Balancing requirements make utilities highly sensitive to the volume and timing of consumption. High variability of consumer loads requires investments in excess capacity only used during critical peak times. Capacity investments are allocated across all customers. If cost allocation is not adequate, higher penetration rates of DG also reduce the number of customers covering high fixed costs such as peak generation and transmission assets. A decreasing number of ratepayers are left to cover the costs, increasing monthly bills, leading to a death spiral. A death spiral can happen when high costs cause consumers to switch to a competing technology reducing the number of consumers available to recover costs raising the prices for the remaining customers (Costello and Hemphill 2014).

Caps are often placed on net metering programs to prevent consumers from over-investing in distributed generation assets, limiting the risk of price volatility and over generation faced by utilities. However, some net metering programs restrict the generation capacity, and others encourage right-sizing through rollover credit policies, for example, only carrying credits forward one month (Smith, Koski, and Siddiki 2021). In addition, utilities restrict how long generation credits are valid. When credits expire, the consumer cannot benefit from the electricity produced from the on-sight generation, thus encouraging the size of the installation to be no more than the household's electricity needs (Poullikkas, Kourtis, and Hadjipaschalis 2013).

Capacity limits reduce the utility obligation from purchasing excess electricity but do not address the risks and opportunities of price volatility. During peak periods, costs to produce and deliver electricity can grow exponentially. Demand response programs are used to reduce demand during periods of high demand. Demand response programs are structured around incentives or prices. Incentive programs compensate consumers for reduced demand while price-based demand response adjusts the price to reflect demand. Time-of-use pricing has two or more prices throughout the day depending on the typical load during that time. Peak and off-peak prices are predetermined and published by the utility and may change seasonally. Wholesale prices often determine Real-time pricing. Wholesale prices fluctuate with the cost of generation needed to meet demand at that time. Real-time prices reflect the cost of generating and delivering a unit of electricity, making the price a strong signal to consumers and a good proxy for the costs of delivering electricity at that time (Albadi and El-Saadany 2008). Consumers who adopt DER could be incented to reduce their consumption by paying rates that more accurately reflect the conditions at that time. As rates increase, so does the opportunity cost of using or storing electricity for consumers who have adopted DER. If rates paid for contributed electricity increase to reflect the supply and demand imbalance, consumers might contribute more electricity when rates are higher. Under net metering, most states (29 states) compensate consumers for excess electricity at retail rates (Smith, Koski, and Siddiki 2021).

Capacity limits for DG are a reasonable risk reduction approach given the variability of consumption and productions and no storage. Without storage, DG reduces total load and associated revenue but increases demand during peak periods. Typical peak generation times for solar panels are between 11 am and 4 pm ("What Time of the Day and during the Year Does a Solar System Work?" n.d.). However, some solar generation may fall outside the typical peak times (11 am to 4 pm), depending on the season and local conditions. According to an NREL factsheet, solar panels provide significant production during peak consumption times, between 4 pm and 6 pm (National Renewable Energy Laboratory (NREL) 2013). However, utility peak times often start when solar generation is declining, around 7 pm. Even if some of the consumers' needs are met in the first hour of the peak time, the utility could still save some significant expenses. Net metering, and distributed generation in general, threaten utility business models. Greater adoption of distributed generation could lead to a death spiral where DG adoption increases costs for those who remain on the grid, making DG more attractive.

Costs of batteries have become more competitive, making distributed energy resources more appealing. Different regulations are being adopted to better incorporate DER, such as Prosumer Aggregation Policies (Moura and Brito 2019). One example of a prosumer aggregation policy is Federal Energy Regulatory Commission (FERC) Order 2222 (*FERC Order No. 2222*, n.d.), allowing small, behind-the-meter meter distributed energy resources to participate in wholesale markets. Once fully implemented, FERC 2222 will allow distributed generation and storage installation of less than 10kWh to sell electricity at real-time prices. FERC Order 2222 could be a more competitive substitute for net metering programs. However, it is unclear what the implementation will be as the rules are still be evaluated by local governing bodies.

Exposing consumers to wholesale price volatility could be detrimental to consumers. Unpredictable and large swings in pricing could force consumers to choose between heating and cooling or suffering unbearable temperatures. Batteries present an opportunity for price arbitrage or hedging, and distributed generation offers a substitute for grid electricity. DER could be a better incentive for consumers to adopt renewable and distributed generation if consumers can participate in wholesale markets.

This paper explores how DER technology and dynamic pricing combine to impact consumer's electricity demand and bills. For the simulated households, we expect to see bills reduce and stabilize with the introduction of more dynamic pricing and onsite generation and storage. Providing consumers with an onsite storage and generation option should create an opportunity for consumers to improve returns on investment in DER technology. When coupled with RTP, consumers investments may present an option to shift from presumption to production. Section two describes the data generate to approximate local conditions, technology configurations, and calculations used in the simulation. Section three presents the results using a few select geographic locations as examples. Section four discusses, and section five concludes.

## Material and methods

We use simulations of household electricity consumption to identify the effects of different technologies and pricing structures. Simulations are run in different geographies to control for weather and price sensitivity. We model two households each in three states to account for different climatic zones. Within states, the two households are located within different independent system operator (ISO) networks to allow for differences in pricing, resulting in a total of six household simulations for each technology and pricing configuration.

Three different technology configurations were run using three different pricing schemes for each of the six households. Energy demands are adjusted according to regional price sensitivities before calculating billing information. Simulations were run using a house of the same size, appliances, and the number of occupants. See Table 11 for configuration options. Consumer electricity needs are simulated using the System Advisory Model (SAM) developed and distributed by the National Renewable Energy Lab (NREL) (Freeman et al. 2018). Technology impacts were evaluated first by adding a solar array to the base house with a grid connection and then adding a battery to the solar configuration. Each household and technology configuration has demanded load adjusted according to different pricing schemes.

Several measures are used to approximate and evaluate the welfare of customers and utilities. The measures used are based on "Managing the Benefits and Costs of Dynamic Pricing" (Faruqui and Lessem 2012) and include price volatility as a measure of risk, reward in gains from trade, consumer bill stability, and changes in consumption.

**Geography**

Geography can significantly impact electricity consumption and generation due to differences in weather and the amount of sunlight. Real-time prices were downloaded from wholesale markets for 2019. Because not all of the US has access to wholesale price data, the center of the US was selected to provide as much geographic diversity as possible. A northern, southern, and central city was chosen from the central US area. The northern city, Fargo, ND, was selected because it is covered by Southern Power Pool (SPP) and Midcontinent Independent System Operator (MISO). Similarly, Houston, TX, was selected in the south because data was available from the Electric Reliability Council of Texas (ERCOT) and MISO. St. Louis, MO and Kansas City, MO were selected for the central region because of the similar latitude and different ISO's, MISO, and SPP, respectively. Table 1 is provided for reference.

**Load data**

A majority of electricity consumption is determined by heating, cooling, and the physical characteristics of the house. SAM is used to generate load data and considers the DER technology installed, appliances in the home, weather, and solar data for the location and number of occupants. SAM generates hourly load data for one year. Weather and solar data were imported into SAM from NREL's National Solar Radiation Database (NSRDB) ("NSRDB Data Viewer" n.d.). NSRDB provides typical meteorological year (TMY) data that represents the median annual weather conditions ("TMY - NSRDB" n.d.). TMY is used to show common weather patterns for a particular and reduce outliers that may happen year to year. Electricity prices are set in SAM to estimate customer bills (Freeman et al. 2018).

To evaluate the impact pricing and technology and any potential differences caused by geographies, such as weather, the same house, and DER technology configurations were used in all scenarios. Weather data from the specific region is based on the location of the city used in the analysis. Most of the default options in SAM are accepted. Table 11 contains the relevant SAM settings. Our SAM configuration included a 2000 square foot two-story house with four occupants with heating and cooling set between 68- and 76-degrees Fahrenheit. Most appliances are assumed to be electric and include cooling, washer, dryer, dishwasher, refrigerator, and stove. Heating is not assumed to be electric because only 29% of homes have electric heat, according to ("One in Four U.S. Homes Is All Electric - Today in Energy - U.S. Energy Information Administration (EIA)" n.d.)

**Pricing and elasticity**

More dynamic prices should send stronger signals to consumers about the scarcity of generation and distribution capacity leading to a greater shift in consumption. Three different pricing schemes are used to approximate consumer responses to varying levels of dynamic pricing. Static prices are used as the basis for comparison and use a single price based on the average prices for the state based on EIA data from 2019 ("State Electricity Profiles - Energy Information Administration" n.d.). Time of use pricing defines peak and off-peak times with a higher fee for peak hours. Higher prices are set for peak time to encourage consumers to shift consumption to off-peak times and allocate costs according to increased demand during higher demand times. A 3:1 ratio of peak to off-peak prices was used to have a sufficient difference between pricing periods. A 3:1 ratio was a large enough pricing difference to cause a significant response in demand, according to Charles River Associates (Charles River Associates 2005). Finally, real-time prices are evaluated with hourly pricing data collected from the closest pricing location available from the ISO.

RTP prices are based on locational marginal prices (LMP) from the nearest (approximate) LMP from the wholesale independent system operator (ISO) LMP. LMP locations are approximate because some locational information is proprietary and not published by the ISO. ISO prices were downloaded from the regional provider for 2019. Because prices are real prices published by the ISO, they represent actual events from 2019. Real pricing provides actual price fluctuations but also introduced additional variation caused by local outages and severe weather events. Impacts of pricing outliers can be seen in RTP demand charts in Figure 5 through Figure 10. Significant changes in prices lead to outliers in demand.

Previous research has found that the price elasticity of demand for electricity changes from region to region. To reflect the differences in elasticity, we use the elasticities provided in Table 2 taken from (Bernstein and Griffin 2006). The analysis period for this study is one year, so only short-run elasticities are considered. Regional elasticities are used to adjust demand provided by SAM based on changes in price, as described below in the "Simulating Load, Pricing, and Elasticity (the model)" section.

**DER Technology configuration**

The base system is a grid-connected house with no solar or battery. To evaluate DER options, a 10-kW solar installation is added to the base system, and finally, a 15-kWh battery is added to the home. FERC order 2222, an order to allow DER to participate in wholesale markets, defines DER as small-scale distributed generation and storage between 1 and 10 kWh. The largest system size of 10-kWh is used for the solar and solar+battery setups. While a 15-kWh battery may be outside the definition of DER in FERC order 2222, the reference battery, a Tesla Powerwall, is roughly 15-kWh. Battery installation costs were ignored. A simulation of one year is run to estimate the load for each of these systems on an hourly basis.

Batteries add a lot of flexibility for consumers based on their individual preferences. Electricity can be purchased ahead of high consumption periods or stored when generation exceeds demand. The simplest use of batteries is considered in this study to reduce consumer preferences and the associated complexity. SAM's peak shaving mode with a look ahead to forecast demand is used to manage batteries. Batteries are used to store electricity to reduce peak demand. Peak demands are reduced by forecasting demand and storing electricity to smooth overall demand, shifting grid loads from higher to lower demand periods.

Peak shaving algorithms attempt to smooth consumption by reducing peaks. Other algorithms may better suit other consumer preferences and, for example, increase return on investment but risk a higher bill or a potential outage. The selected peak shaving algorithm assumes all peak loads are the same and shifts the peak loads to lower consumption times to lower costs. Different battery dispatch algorithms are likely to yield substantially different results. Some demand response programs allow a utility to manage the energy settings of a home, such as temperature settings. Like existing demand response programs, ownership and usage rights of batteries could also impact the selection and dispatch approach; utilities will likely have different success criteria than homeowners.

**Simulating Load, Pricing, and Elasticity (the model)**

SAM produces estimates of the energy required to meet the demands of the occupants. SAM's estimates include how much energy is needed to maintain the ambient temperature inside the house preferred by the occupants given the outside temperature or how much energy is needed to heat water for showers and run the dishwasher. Energy needs ($q_{dhi}$) are estimated by SAM ($f_d(w_{dhi}, h)$) based on weather ($w_{dhi}$) for a given hour (h). SAM also includes occupant activity which introduces some random variance ($\varepsilon$).

Equation 1

$$q_{dhi} = f_d(w_{dhi}, h) + \varepsilon_{dhi}$$

Though SAM includes pricing data, prices are only considered when calculating bills. We assume that consumers are sensitive to price fluctuations and reduce the estimates generated by SAM according to the changes in price. The percentage change in price ($P_d$) is calculated based on the current hour's price ($P_h$) and the previous hour's price ($P_{h-1}$).

Equation 2

$$P_d = \frac{P_h - P_{h-1}}{P_{h-1}}$$

The change in quantity demanded is determined using the percent change in price ($P_d$), regional elasticity ($\eta$) according to (Bernstein and Griffin 2006), and estimated energy needs produced by SAM ($q_{dhi}$).

Equation 3

$$Q_{dhi} = (1 + \eta P_d) q_{dhi}$$

The quantity demanded is reduced by the onsite generation ($q_{gen}$) for solar configuration. Equation 4 below shows the reduction in grid demanded electricity in calculating the annual bill.

Equation 4

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!'$"'$

Batteries create many opportunities for optimization. Because net metering effectively allows consumers to treat the grid as energy storage, adding a battery eliminates the need for a net metering policy. By selectively charging and discharging the battery can further improve the value capture by adding a battery. SAM's default behind the meter battery dispatch algorithm is a peak shaving approach intended to shift the highest use times to the lowest use times. By looking at a twenty-four-hour period, SAM is able to discharge the battery during the periods with the highest consumption and charge when the consumption is lowest. The method that SAM uses takes advantage of the perfect knowledge provided in the simulated environment. All weather, load, and generation data are accessible and can be used in a forecast. The perfect knowledge provided makes the results optimistic (DiOrio 2017). Optimistic results and simplicity of the approach make SAM's peak shaving algorithm a reasonable option for this study.

Net metering policies create a constraint that the expected value of installed solar is no greater than zero over the year. However, day to day, the expected value may be positive or negative. The constraint is imposed by limiting the system's generating capacity or by restricting how credit's rollover. Longer-term credit policies can allow consumers to consumer credits in the winter that were earned in summer. Shorter-term policies may apply credits only to the next monthly bill.

Equation 5

$$E + \sum_{!'\$}^{,-.} \sum_{"'\$}^{\%\&} ((\,(_{*+} - \&_{!"()})\,!_{!"(}, <= 0$$

Removing the constraint may create an incentive for consumers to invest in larger DER setups, producing more than they need. Limitations included in NEM policies and FERC 2222 reduce the risk of a consumer over generation. Installing onsite storage and more dynamic prices shifts the risks of over generation and price volatility from utilities to consumers. Ignoring capacity limits and rollover credit periods can provide greater insight into the potential loss or gains for utilities and consumers. We expect to see a greater return on investment for Solar+Battery systems with RTP and a greater cost for utilities for Solar systems with dynamic pricing.

In addition to greater returns for consumers with batteries, we expect to see overall bills reduced by onsite generation. Onsite generation is a substitute for grid electricity and should reduce the consumer's bill but not reduce the electricity demanded. Solar generation should produce a "duck curve" for the consumer, where generation is greater than consumption in the middle of the day and consumption is greatest in the evening when little solar generation happens.

Batteries should significantly flatten the peaks and valleys of consumption. Shifting demand from the peaks in the evening to the lows of the morning should reduce overall grid demand and monthly bills creating a monthly excess in generation and negative bills.

Real-time pricing should produce the greatest impact on demand while being revenue-neutral. Solar generations cannot be controlled by the consumer or utilities and will likely produce the worst response for both without batteries. Including batteries, however, should allow consumers to take better advantage of pricing. Further advantages could be gained for the consumer by improving battery dispatch algorithms, though profit maximizing is out of the scope of this paper.

## Results

### Consumer bills

Seasonal variations of consumers' bills are expected, especially because cooling is assumed to be electric while heating is not. However, smaller, more consistent monthly bills are beneficial to consumers. As demonstrated in Figure 11, dynamic pricing and the addition of DER technologies reduce consumers' bills. The general pattern of bills shows higher costs in the summer months, and the addition of solar creates negative bills in the spring months, Houston, Texas, on ERCOT pricing being the exception that has a large increase in August for grid-connected real-time pricing and a substantially negative bill for solar and solar+battery for the same month. The addition of dynamic pricing appears to further smooth and reduce bills. Lower bills are likely due to reduced peak demand when prices are highest.

Greater details of changes in monthly bills can be seen in Table 3 through Table 8, which show the mean and standard deviations decreasing with the addition of DER technology and dynamic pricing. A cross-sectional analysis in Table 9 illustrates the change in bills when pricing and technologies are combined, while Table 10 focuses on the impact of pricing for each technology. The consistent differences between peak and off-peak prices cause a consistent decrease in bills. Real-time pricing volatility causes variance in bills. Combined effects of technology and pricing show significant improvements resulting in a greater than 100% drop in bills. Looking at pricing effects on technology shows volatility introduced by the solar generation, which is reduced with the addition of a battery, TOU differences from solar to +battery. Statistical comparisons of equality in bills are shown in Table 18 through Table 23, specifically, a Kruskal-Wallis test is used to compare three groups of data with a null hypothesis that all three groups are equal. Table 18 shows statistical significance when dynamic pricing is applied to grid-connected households. In contrast, Table 19 and Table 20 show no statistical difference when dynamic prices are applied to solar and solar+batteries, apart from Kansas City, MO. The similarity in the Kansas City, MO bills appears to come from the similarities in pricing impacts across each pricing scheme. Pricing impacts are similar enough to cause what appears to be a type one error related to the way the Kruskal-Wallis test works. Testing for equality of bills for prices across all technologies shows statistical significances demonstrating a change in bills, Fixed price data in Table 21, TOU price data in Table 22, and RTP data in Table 23.

As can be seen in Figure 11 adding DER technology has the largest impact on bills because onsite generation replaces grid demand. The cost of solar and battery are not included in the monthly bills. Including the DER costs would change the outcome though we are only concerned with the monthly bills and not a holistic cost in this analysis.

Negative bills mean the customer has been paid more for the generated electricity than they paid for consumed electricity. A negative balance could be the result of reduced consumption, shifted loads, or excess generation. Assuming that compensation is a positive outcome for the consumer, the best configuration option appears to be Fixed Prices with Solar and a Battery. The worst configuration would be Fixed Prices with no DER. Solar+Battery and fixed prices produced the largest negative annual bills in all six locations, while grid-connected non-DER setups produced the largest annual bills across all six locations.

TOU and RTP lead to lower and more stable bills with a lower mean and standard deviation. Though neither consistently produces the lowest mean bill or standard deviation. The differences are likely due to fluctuations in real-time prices. Real-time prices can have substantial swings that may result from random weather patterns or possibly outages or maintenance issues in the local grid. Extreme weather patterns can negatively impact consumers that could be very costly if consumers are exposed to market prices.

Fixed prices represent a large amount of risk for the utility, however. Considering the risks associated with price volatility, Fixed Prices without DER would be the best option for the utility because they bear the risks of price fluctuation. Solar alone would be the worst option for utilities because of the price volatility and the addition of the lack of control and limited predictability of the distributed generation. The addition of a battery reduced the risks related to the stochastic nature of Solar generation and makes DER a dispatchable source of electricity. Batteries, however, do make the division of cost and value more difficult. Utilities should be compensated for the use of the grid, and consumers should be compensated for the value they contribute, which includes some distribution savings and generation costs.

DER technologies are a substitute for grid generation and increase household grid independence reducing and stabling bills, shifting variable costs to fixed costs reducing variable costs represented as bills. Fixed price non-DER bills are the largest and have the largest variation. When the consumer is paid retail prices for excess generation, their bills are effectively reduced to zero, and more dynamic pricing options further reduce bills, even becoming negative. Solar, especially as distributed generation, is uncontrollable and is not dispatchable. Paying retail prices through net metering policies could be costly for utilities. Adding battery allows additional control to DER, creating a dispatchable source of electricity and reducing the need for net metering policies. Though the algorithms do not specifically attempt to be profitable, reducing peaks leads to greater bill reductions, leading to more significant negative balances.

More dynamic prices further enhance the effects of the DER technology, as shown in the detailed Table 3 through Table 8 and cross-sectional comparison in Table 9 and Table 10. The 3:1 peak to the off-peak ratio used for TOU produces a fairly consistent drop in bills with an average of 45% reduction across all technology options and a 37% drop from fixed pricing in non-DER setups. RTP introduces variations that are likely related to specific supply and demand peaks in the geographic area. RTP creates a 65% drop on average across all technology. Batteries produce the least decline in bills (53% on average), and solar has the greatest average drop (75%), non-DER bills dropped by an average of 68%. Fargo, ND RTP on MISO is an example of an extreme outlier producing a 280% drop in bills, but SPP for the same city only dropped by 76%.

**Consumer Load**

Customer bills only show the cost reduction but do not show how demand is impacted. Reduction in loads reduces revenues for utilities and can have a negative impact on consumer experience. High prices may force consumers to reduce the load by cutting back on cooling or other time-sensitive activities or reschedule activities (I.e., bad customer experience).

Some loads can be shifted like taking a shower in the evening or moving laundry day to Wednesday Mornings instead of Saturday evening. Other more time-sensitive loads can be curtailed but can be a negative experience for consumers, such as not watching a movie for family night or changing thermostat settings because electricity is too expensive. Consumers may be able to reduce bills in the short run but in the long run higher prices, or drastic swings in prices may force consumers to seek substitutes.

In Fargo, ND on MISO, Fargo, ND on SPP, and Kansas City, MO, Grid-connected households show statistically significant differences between pricing schemes. The other grid-connected households do not show statistically significant differences. Solar and solar+battery households do not show statistically significant differences between pricing schemes, Table 12 through Table 14. Technology impacts are compared in Table 15 through Table 17 indicating strong statistically significant differences.

Looking at peak loads for each hour per month in Figure 1, Figure 2,

Figure 3, and Figure 4 show that DER technology has a much larger impact than dynamic pricing. Figure 1, Figure 2, and Figure 3 St. Louis, MO MISO Peak Hourly Load per Month (Grid Connected)show that, for each given technology configuration, the peak hourly load is very similar across all three pricing strategies. Dynamic (TOU and RTP) prices increase the effect of DER technology, further reducing peaks but otherwise have a far less significant impact on peak demand. However, Figure 4 shows substantial changes in peak hourly loads across technology configurations for a given pricing structure.

**St. Louis, MO MISO**
**Peak Hourly Load per Month**

*Figure 1, St. Louis, MO MISO Peak Hourly Load per Month (Grid Connected)*

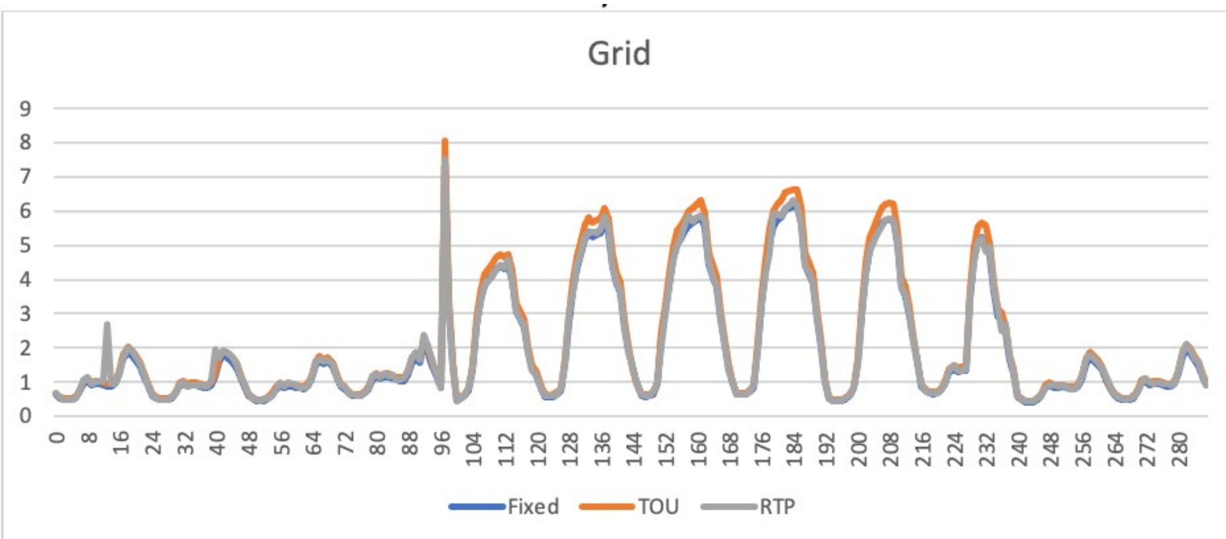



*Figure 2, St. Louis, MO MISO Peak Hourly Load per Month (Solar)*

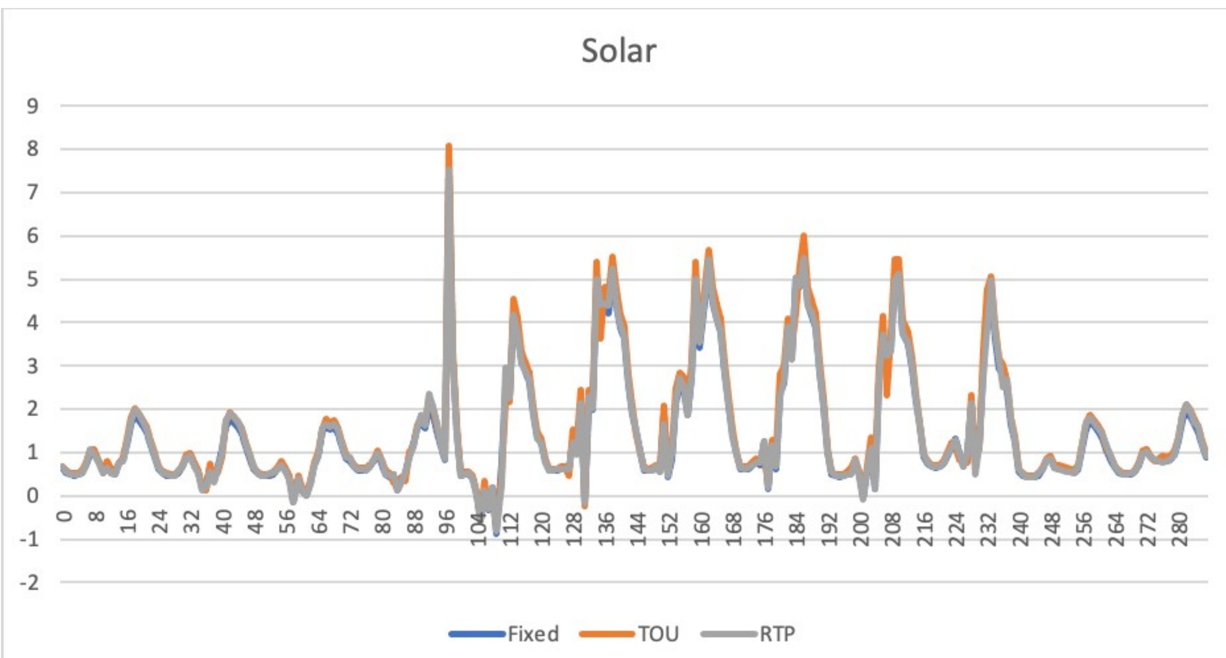


*Figure 3, St. Louis, MO MISO Peak Hourly Load per Month (Solar+Batteery)*

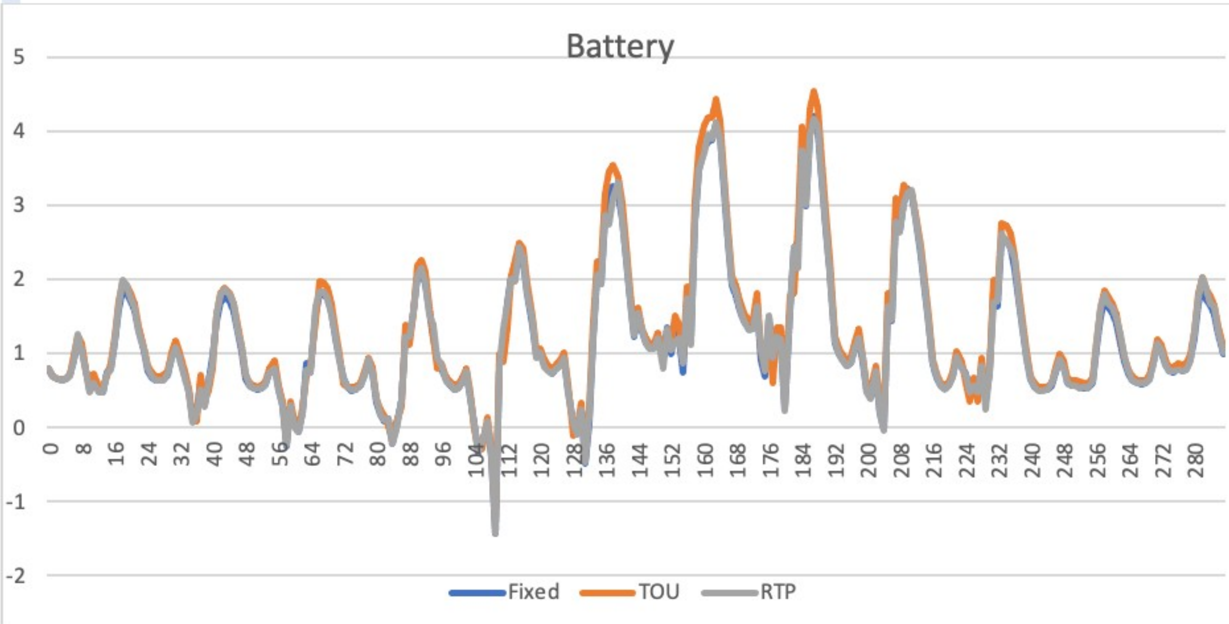
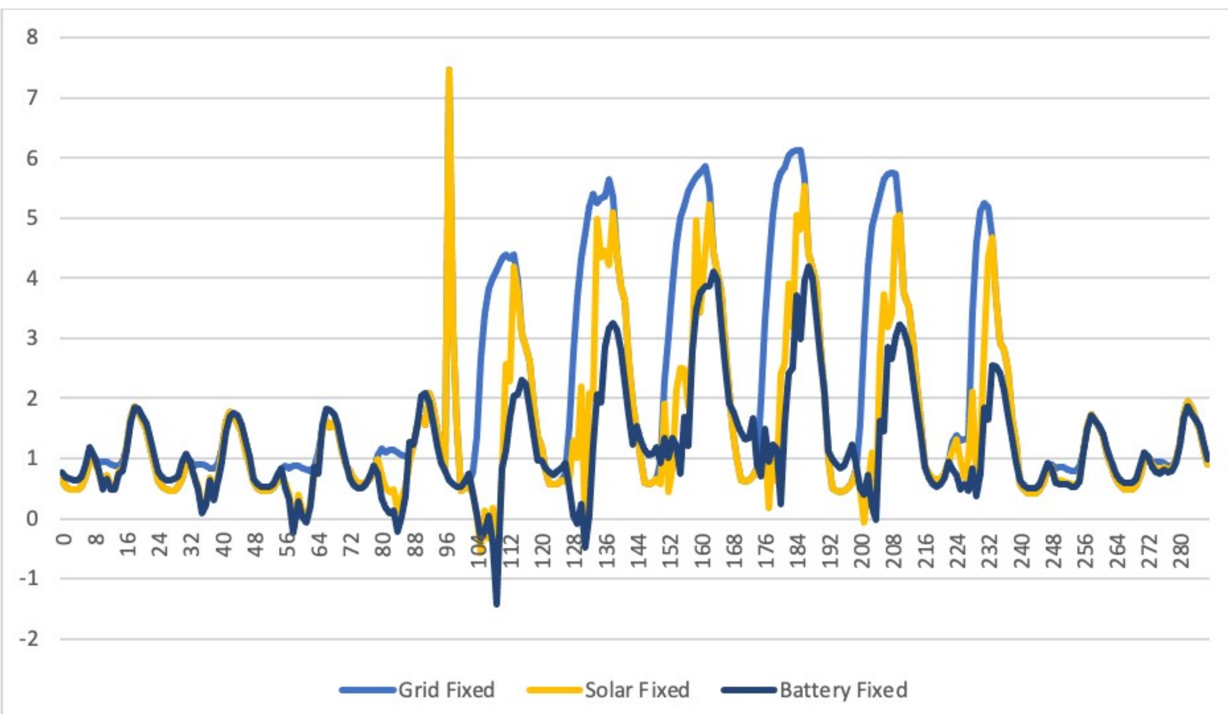



*Figure 4, St. Louis, MO MISO Peak Hourly Load per Month comparing Fixed prices*



Tables 15 through 20 show statistical results for the differences in load for each technology across pricing structures and for each pricing structure across technology configurations. The results confirm what Figures 1 through 4 suggest. There is no statistically significant difference in demand load for any given technology when different pricing structures are imposed. However, demand load is statistically different across technologies for any given pricing structure. This suggests that, even assuming consumers observe hourly price changes and respond to those changes in their consumption decision, pricing has little impact on peak load demand.

**Conclusion**

Onsite generation is a substitute for grid generation and causes a substantial drop in grid-consumed electricity. However, solar generation cannot be controlled or dispatched, and generation is primarily outside of typical consumption hours. Installed generation capacity is often limited through policy and may also force credits to expire to limit or prevent the profitability of DER assets. Capacity limits appear to reduce the risks of the consumer over generating, which could be costly for utilities and may lead to grid stability issues. The addition of a battery makes DERs dispatchable, reducing the risks of excess solar generation and the associated costs for utilities to purchase consumer generated electricity. Allowing consumers with batteries to participate in wholesale markets using dynamic pricing such as RTP could create a strong incentive for consumers to invest in additional generation and storage while not forcing utilities to purchase excess generation. Dispatchable distributed assets could also benefit utilities through lower costs of distribution and greater grid stability by providing access to electricity closer to where it is consumed.

Capacity limits reduce the complexity and liabilities prosumers add to utilities. Allowing DER enabled households to participate in the market removes the need for utilities to purchase excess electricity but also reduces or eliminates the revenue from that household. Given the current 10 kW capacity limit, household bills are reduced by roughly 100%. By doubling the capacity limits, the DER setup could produce as much electricity as the household previously consumed. Prosumers that install larger systems then would primarily produce electricity that benefits the utilities by, for example, helping to meet peak demand. Because solar generation cannot be controlled, doubling generation without onsite storage would only increase the generation outside of typical consumption times. Policies could be adjusted to require paring of storage and generation to allow households to install larger systems.

Though pricing has a smaller impact than technology, the signal sent by pricing affects consumption. The grid only households show the largest change from dynamic pricing in Table 12 and 18, households with solar also show some change in consumption, but the effect is much smaller. RTP can encourage consumers to shift demand and expose consumers to potential financial burdens during extreme pricing events. DER households with onsite generation and storage are unlikely to experience the downside of an extreme price event because most or all their electricity is generated onsite. Future policies should take price volatility into consideration because of the potential downsides. Clear communication and acceptance of those risks by consumers are important. Alternative pricing schemes that share the risk and rewards could be developed and offered to consumers unwilling or unable to bear the risks.

Dynamic pricing also impacts consumption but to a lesser extent than bills. Electricity's inelastic demand may cause a lower effect from pricing. Fixed prices and no cap create the best opportunity for consumers in terms of returns on investment, but consumers are benefiting at the expense of the utility. Capacity limits are a useful tool for utilities and regulators if dynamic pricing options are not available. However, DER installations with batteries and onsite generation appear to provide an opportunity for consumers and utilities to work more closely to generate more electricity on a smaller scale and more distributed way.

Adding batteries to a household allows the storage of electricity generated onsite and adds the option to shift loads. Load shifting with a battery enables consumers to save on their bills by purchasing lower-cost energy to consume during higher-cost periods. Shifted loads are an ideal outcome for both the consumer and utilities. Peak loads are reduced, and the consumer does not need to modify behavior or forego activities that consume electricity.

In addition to bill savings, consumers can earn income from the sale of electricity. Though the revenue is small relative to the cost of the DER installation given current capacity limits, any excess is an indication that even small-scale generation could be profitable for consumers. Consumers selling excess generation at fixed retail rates result in the largest payments, shown as a negative bill. Though higher payments may be a good outcome for consumers, the obligation for utilities to purchase at retail rates does not fully account for risks to the utilities. Real-time pricing, especially for consumers with storage and generation, may be a better way to share risk between consumer and utility. This analysis did not consider a profit-maximizing consumer that could lead to different consumption patterns and bill outcomes.

As can be seen in the changes in demand for grid-connected households (Table 12 and Table 18), dynamic pricing can be an excellent signal to consumers and encourages consumption shifts away from high demand or low supply times. Greater control over electricity contribution to the grid, such as batteries, can also create an opportunity cost that leads to more significant contribution during low supply times that may benefit utilities. Due to the pace of prices changes, another technology is needed to react promptly. Telecommunication devices and smart energy management could be combined to respond to rapid price changes that a person would not be able to. Current solutions require some interaction by the consumer to respond and modify their energy consumption, such as changing thermostat settings or turning off devices. Consumer's inability to respond to changes in prices demonstrates the risk faced by consumers to greater price volatility. Because extreme weather events or critical infrastructure problems can be detrimental to consumers, if they cannot respond quickly enough to price changes, they may face significant financial burdens. An extreme cold weather pattern caused such an event in Texas 2021, leading to outages across the state and unexpected bills for some consumers.

Capacity limits appear to do a good job of reducing the liability for utilities by limiting generation to enough to cover household electrical needs. Though capacity limits reduce the liability for utilities, they also reduce consumer investment choices. The above results suggest consumer value may be destroyed through restricted "use it or lose it" credit rollover policies included with net metering policies. The negative bill balances reported in Table 3 through 8, which reflect net value creation for consumers, are wiped away when credits cannot be rolled forward. As a result, any additional investment from consumers would result in net generation that creates zero value for the consumer, thus discouraging further investment. Bills are near zero with existing capacity limits. Limiting self-generation also does not address the risks of outages or price volatility for consumers. Adding storage to consumer DER installations reduces the need for capacity limits and allows consumers to store energy rather than carry credits.

Allowing DER to participate in wholesale electricity markets benefits utilities by removing the obligation to purchase electricity from consumers. However, the utilities will still need to manage the electricity that is added to the grid. Operational challenges aside, consumer participation in the wholesale market is beneficial to consumers and utilities. Additionally, capacity limits should be increased to allow greater generation to increase consumers' return on investment and, therefore, increases the incentive to adopt DER technologies. Once a greater number of consumers adopt DER technologies, pricing policies could be reviewed to enhance consumer behaviors.

**Future research**

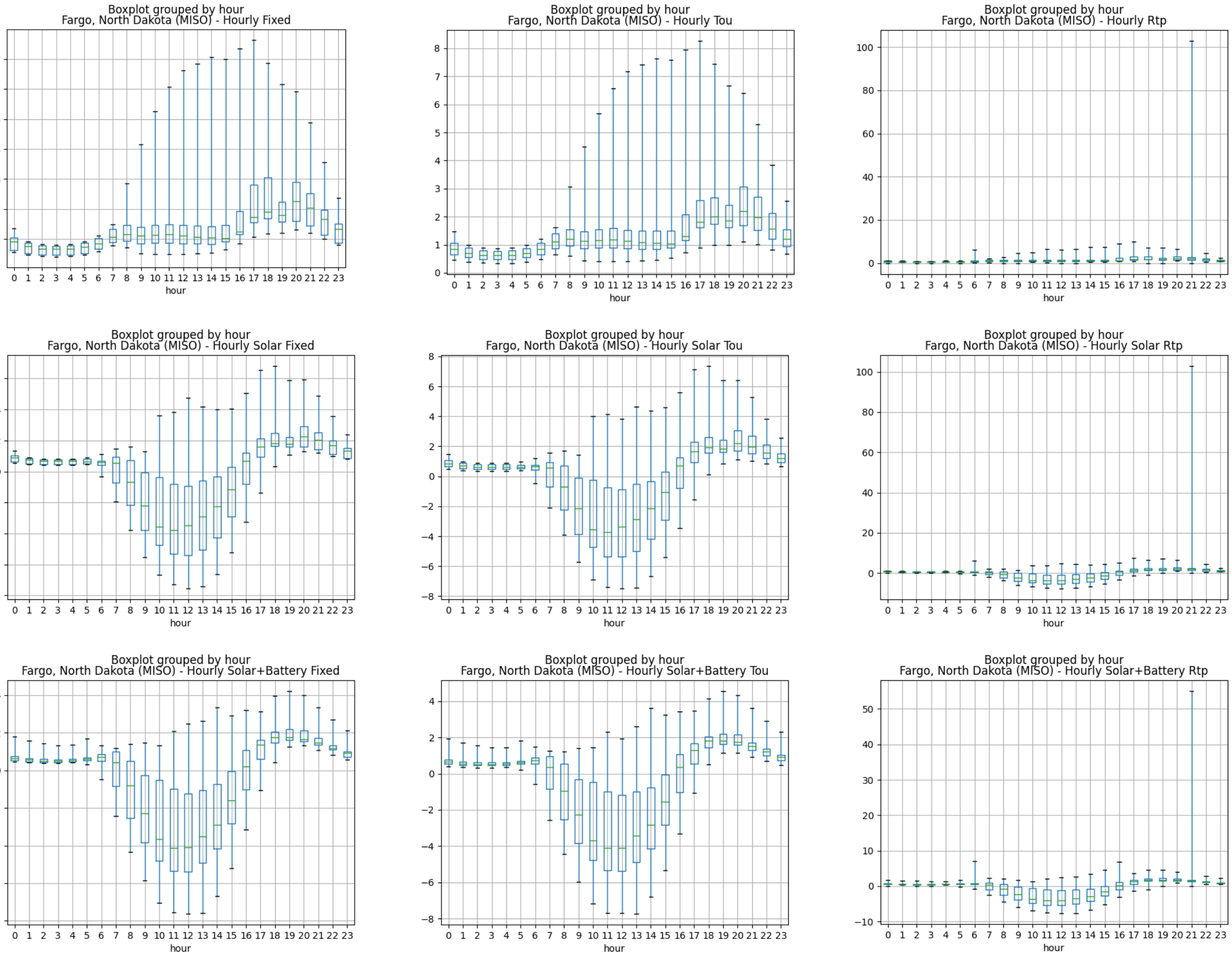
Capacity limits prevent consumers from installing generation beyond their needs. What benefits are gained or lost by increasing or eliminating capacity limits? FERC order 2222 will allow DER participation in wholesale markets, creating an opportunity for distributed generation to be a greater source of renewable electricity in the generation mix. Small-scale, distributed batteries could also be used to capture excess renewable generation that may otherwise be curtailed or sold at negative prices.

Pricing policies, like TOU use price to force consumption behavior in aggregate. Using an aggregate measure similar to elasticity to estimate or forecast the target reduction could lead to equity issues. Because electricity is an input for household activities demand, each activity will have its own utility curve, and each consumer will make decisions to reduce consumption differently. Without a better understanding of the trade-offs, consumers are making in those decisions setting prices to reduce consumption may introduce equity issues. Additional research into energy efficiency adoption, load shifting, and curtailment may identify new ways to incentivize consumer load reductions.

Additional battery management algorithms are likely to lead to different outcomes for consumers' bills, resilience, and profitability. Further research is needed to explore profit-maximizing behavior and adoption for consumers. Not all consumers are likely to invest in larger DER setups. How many consumers convert to profit-seeking behavior will affect how much additional generation the utilities have to manage. Profit maximizing algorithms will also likely create different outcomes for excess generation.

# Fargo, North Dakota MISO

*Figure 5, Annual Hourly Load Demand (Fargo, North Dakota MISO)*



# Fargo, North Dakota SPP

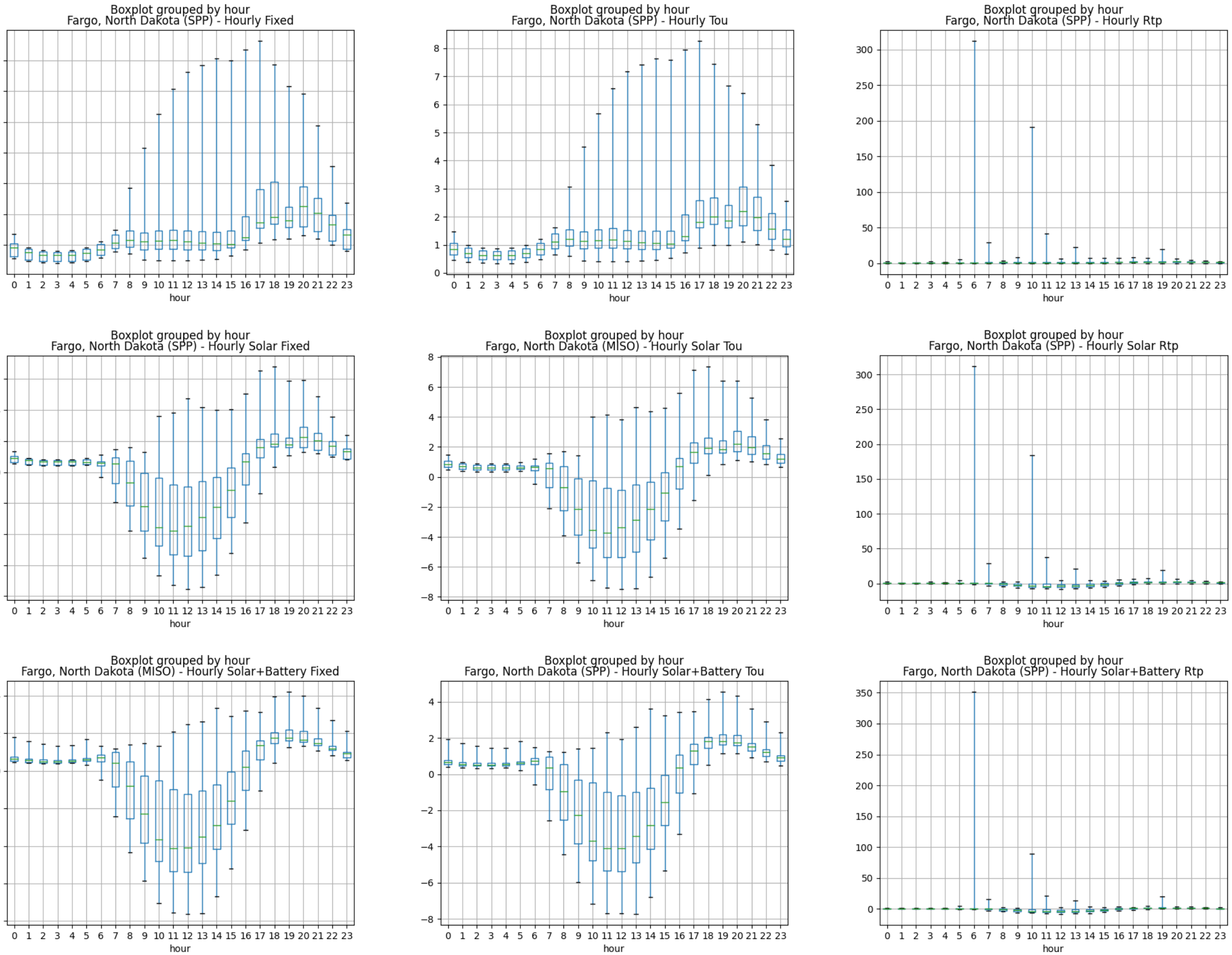
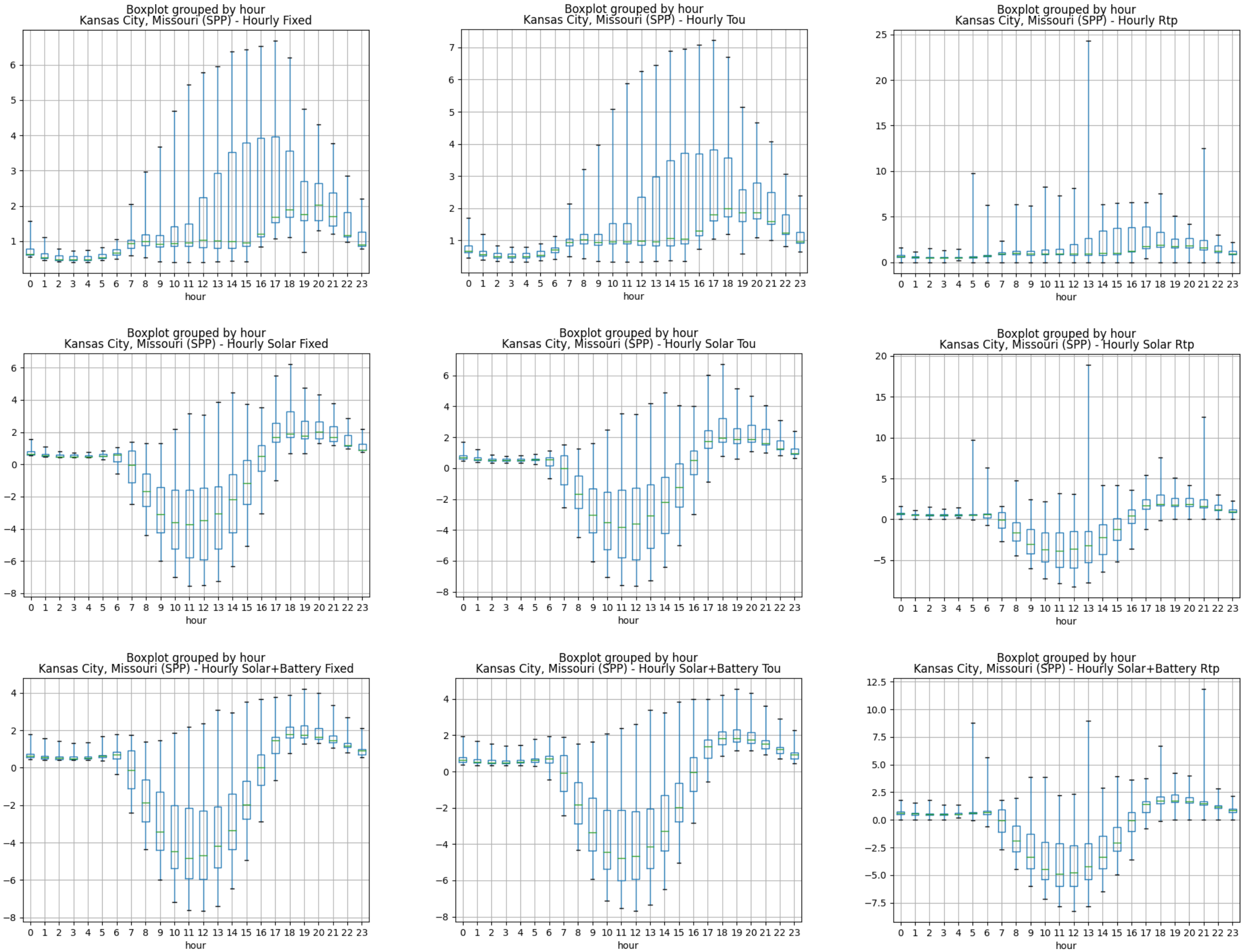



*Figure 6, Annual Hourly Load Demand (Fargo, North Dakota SPP)*

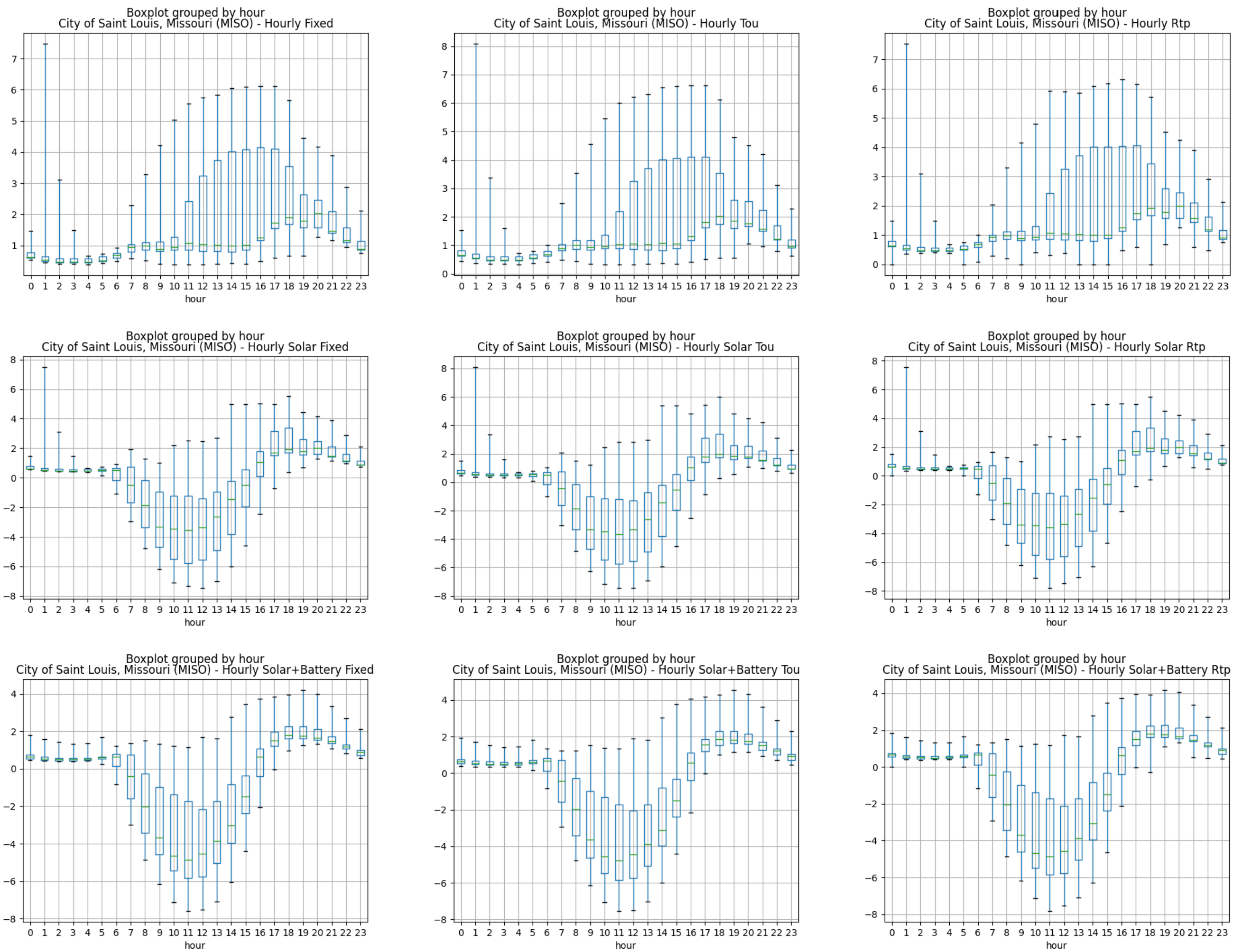
# Kansas City, Missouri SPP

*Figure 7, Annual Hourly Load Demand (Kansas City, Missouri SPP)*



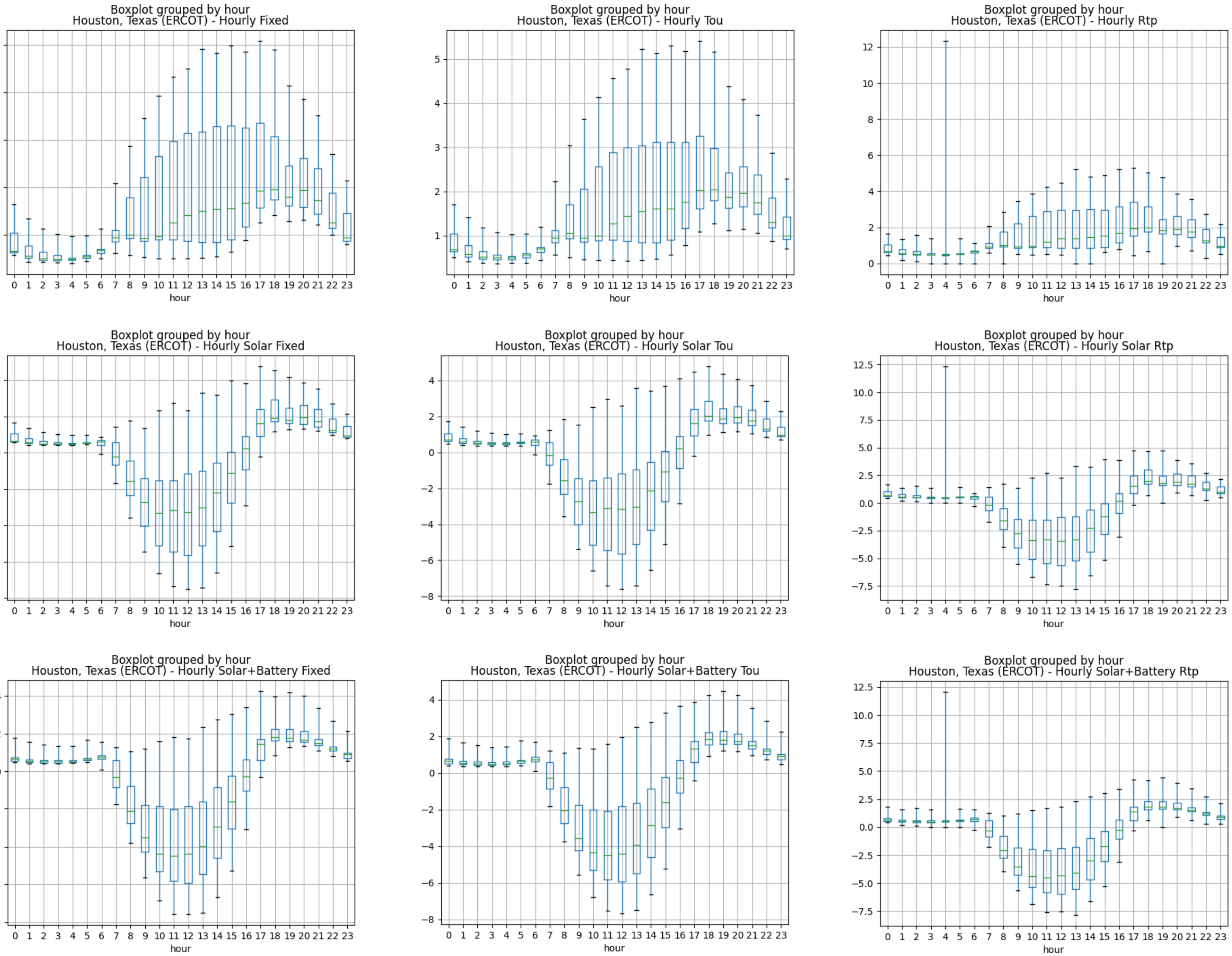
# St. Louis, Missouri MISO

*Figure 8, Annual Hourly Load Demand (St. Louis, Missouri MISO)*



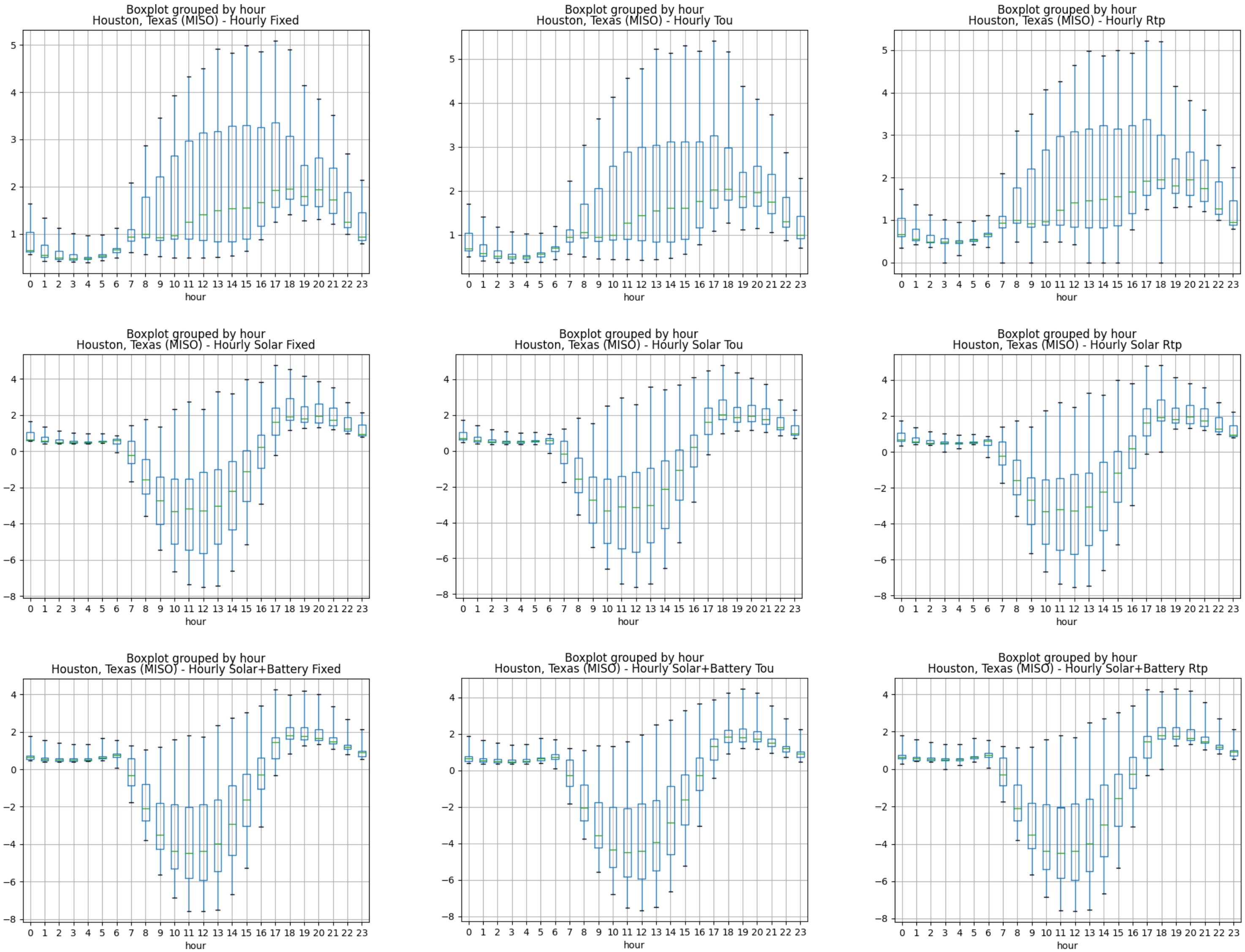
# Houston Texas ERCOT

*Figure 9, Annual Hourly Load Demand (Houston, Texas ERCOT)*



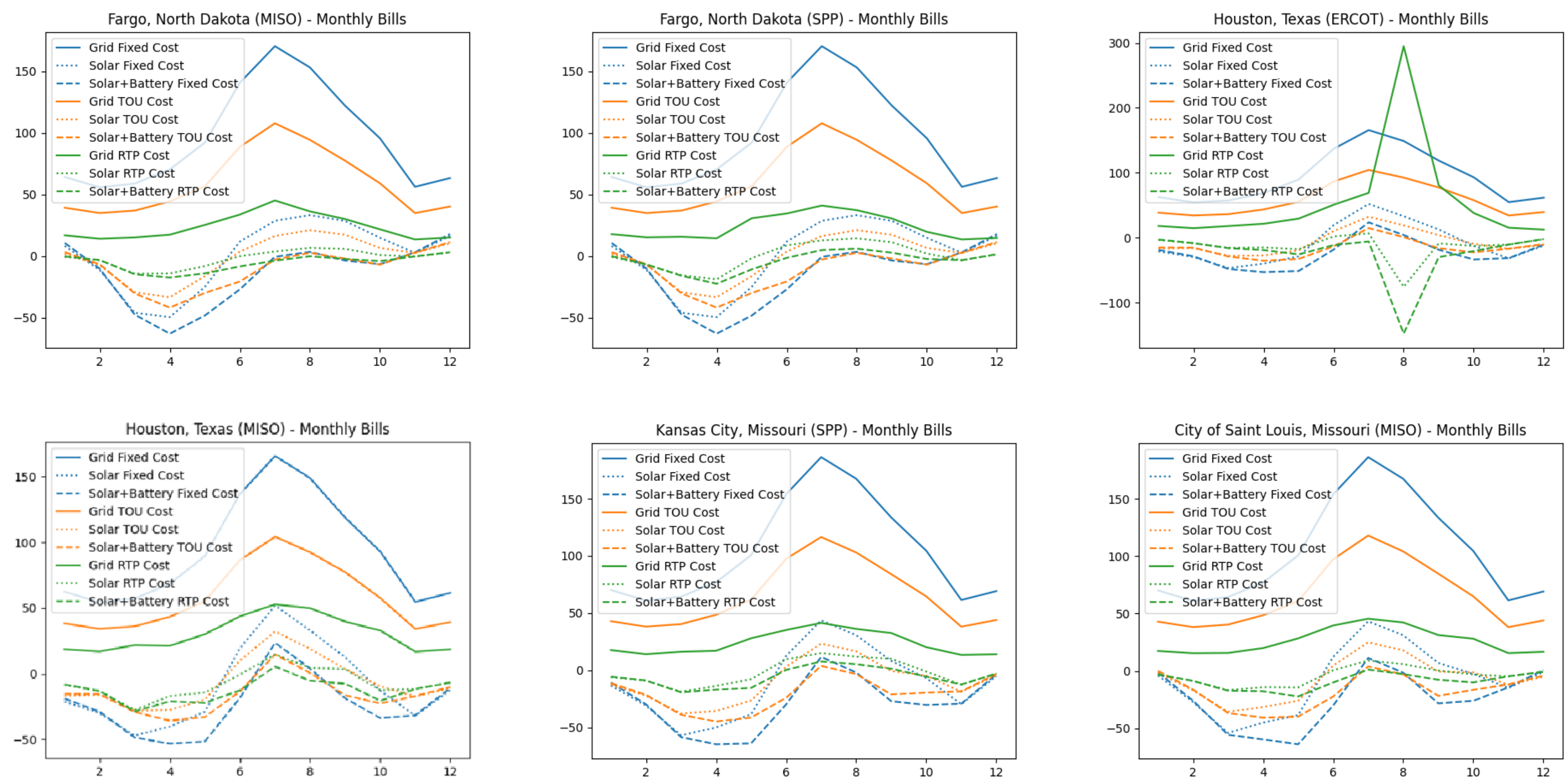
# Houston Texas MISO

*Figure 10, Annual Hourly Load Demand (Houston, Texas MISO)*



# Monthly Household Bills

*Figure 11, Monthly Household Bills*



Simulation Household Location and ISO

*Table 1, Simulation Household Location and ISO*

| Household location | ISO | Nearest Pricing Node |
|---|---|---|
| Fargo, North Dakota | MISO | OTP.MPC |
| Fargo, North Dakota | SPP | OTP |
| Kansas City, Missouri | SPP | AECI |
| St. Louis, Missouri | MISO | AMMO.SIOUX1 |
| Houston, Texas | ERCOT | LZ_HOUSTON |
| Houston, Texas | MISO | EES.SAN_JC2_CT |

Short-run residential price elasticity of demand

*Table 2, Short-run residential price elasticity of demand*

| Region | elasticity |
|---|---|
| South Atlantic | -0.318 |
| East South Central | -0.266 |
| Middle Atlantic | -0.232 |
| Mountain | -0.211 |
| New England | -0.192 |
| Pacific | -0.188 |
| West North Central | -0.163 |
| West South Central | -0.127 |
| East North Central | -0.054 |

Bills in Fargo ND – MISO

*Table 3, Bills in Fargo ND – MISO*

| | **Grid** | | | **Solar** | | | **+Battery** | | |
|---|---|---|---|---|---|---|---|---|---|
| **Month** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** |
| 1 | $64.16 | $39.21 | $16.80 | $8.21 | $1.71 | $(0.68) | $10.62 | $3.18 | $(0.30) |
| 2 | $55.76 | $34.90 | $14.02 | $(11.41) | $(7.44) | $(3.41) | $(10.32) | $(6.74) | $(3.27) |
| 3 | $58.85 | $36.92 | $15.12 | $(46.11) | $(29.45) | $(14.33) | $(47.63) | $(30.43) | $(14.83) |
| 4 | $70.36 | $44.35 | $17.31 | $(49.62) | $(33.45) | $(14.11) | $(63.01) | $(41.86) | $(17.47) |
| 5 | $92.04 | $56.53 | $25.24 | $(25.06) | $(16.34) | $(8.16) | $(48.32) | $(29.98) | $(14.07) |
| 6 | $140.71 | $88.60 | $33.63 | $11.74 | $3.61 | $(0.10) | $(27.05) | $(20.70) | $(8.45) |
| 7 | $170.36 | $107.76 | $45.08 | $28.60 | $16.24 | $3.66 | $(0.63) | $(2.86) | $(3.79) |
| 8 | $153.10 | $94.33 | $36.24 | $33.20 | $20.96 | $6.61 | $3.40 | $2.63 | $(0.18) |
| 9 | $122.13 | $77.45 | $30.05 | $28.53 | $17.27 | $5.80 | $(3.67) | $(2.04) | $(2.38) |
| 10 | $95.58 | $59.04 | $21.66 | $14.83 | $6.58 | $0.84 | $(6.60) | $(6.99) | $(4.13) |
| 11 | $56.20 | $34.86 | $13.45 | $2.57 | $2.47 | $(0.34) | $3.05 | $2.76 | $(0.29) |
| 12 | $63.28 | $40.19 | $15.03 | $16.36 | $10.37 | $2.89 | $17.84 | $11.33 | $3.08 |
| **Annual** | **$1,142.54** | **$714.15** | **$283.67** | **$11.83** | **$(7.46)** | **$(21.33)** | **$(172.31)** | **$(121.70)** | **$(66.08)** |
| **mean** | **$95.21** | **$59.51** | **$23.64** | **$0.99** | **$(0.62)** | **$(1.78)** | **$(14.36)** | **$(10.14)** | **$(5.51)** |
| **std dev** | **$41.35** | **$26.04** | **$10.43** | **$28.23** | **$17.78** | **$7.04** | **$26.02** | **$16.60** | **$6.66** |

Bills in Fargo ND – SPP

*Table 4, Bills in Fargo ND – SPP*

| | **Grid** | | | **Solar** | | | **+Battery** | | |
|---|---|---|---|---|---|---|---|---|---|
| **Month** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** |
| 1 | $64.16 | $39.21 | $17.74 | $8.21 | $1.71 | $(0.68) | $10.62 | $3.18 | $(0.11) |
| 2 | $55.76 | $34.90 | $15.18 | $(11.41) | $(7.44) | $(7.08) | $(10.32) | $(6.74) | $(6.88) |
| 3 | $58.85 | $36.92 | $15.66 | $(46.11) | $(29.45) | $(15.59) | $(47.63) | $(30.43) | $(16.08) |
| 4 | $70.36 | $44.35 | $14.41 | $(49.62) | $(33.45) | $(18.91) | $(63.01) | $(41.86) | $(22.49) |
| 5 | $92.04 | $56.53 | $30.67 | $(25.06) | $(16.34) | $(1.68) | $(48.32) | $(29.98) | $(10.81) |
| 6 | $140.71 | $88.60 | $34.53 | $11.74 | $3.61 | $8.68 | $(27.05) | $(20.70) | $(1.47) |
| 7 | $170.36 | $107.76 | $40.93 | $28.60 | $16.24 | $12.69 | $(0.63) | $(2.86) | $4.85 |
| 8 | $153.10 | $94.33 | $37.22 | $33.20 | $20.96 | $14.37 | $3.40 | $2.63 | $5.97 |
| 9 | $122.13 | $77.45 | $30.50 | $28.53 | $17.27 | $11.21 | $(3.67) | $(2.04) | $2.72 |
| 10 | $95.58 | $59.04 | $19.64 | $14.83 | $6.58 | $1.96 | $(6.60) | $(6.99) | $(2.40) |
| 11 | $56.20 | $34.86 | $13.46 | $2.57 | $2.47 | $(3.43) | $3.05 | $2.76 | $(3.36) |
| 12 | $63.28 | $40.19 | $14.66 | $16.36 | $10.37 | $1.29 | $17.84 | $11.33 | $1.50 |
| **Annual** | **$1,142.54** | **$714.15** | **$284.60** | **$11.83** | **$(7.46)** | **$2.83** | **$(172.31)** | **$(121.70)** | **$(48.55)** |
| **mean** | **$95.21** | **$59.51** | **$23.72** | **$0.99** | **$(0.62)** | **$0.24** | **$(14.36)** | **$(10.14)** | **$(4.05)** |
| **std dev** | **$41.35** | **$26.04** | **$10.24** | **$28.23** | **$17.78** | **$10.62** | **$26.02** | **$16.60** | **$8.63** |

Bills in Kansas City, MO – SPP

*Table 5, Bills in Kansas City, MO – SPP*

| | **Grid** | | | **Solar** | | | **+Battery** | | |
|---|---|---|---|---|---|---|---|---|---|
| **Month** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** |
| 1 | $70.18 | $42.89 | $17.65 | $(13.31) | $(12.75) | $(6.12) | $(10.68) | $(11.14) | $(5.54) |
| 2 | $60.98 | $38.17 | $14.09 | $(30.93) | $(22.23) | $(9.09) | $(29.73) | $(21.46) | $(8.92) |
| 3 | $64.37 | $40.38 | $16.22 | $(56.77) | $(37.80) | $(18.68) | $(58.44) | $(38.88) | $(19.21) |
| 4 | $76.96 | $48.51 | $17.08 | $(50.03) | $(35.62) | $(13.68) | $(64.67) | $(44.81) | $(16.93) |
| 5 | $100.67 | $61.80 | $27.97 | $(38.44) | $(26.43) | $(7.78) | $(63.87) | $(41.32) | $(15.35) |
| 6 | $153.91 | $97.47 | $35.24 | $12.60 | $3.11 | $9.66 | $(29.83) | $(24.04) | $0.37 |
| 7 | $186.34 | $116.48 | $41.42 | $43.66 | $23.34 | $15.03 | $11.70 | $3.83 | $7.71 |
| 8 | $167.46 | $102.99 | $36.18 | $30.66 | $16.56 | $11.97 | $(1.92) | $(3.30) | $5.30 |
| 9 | $133.58 | $84.04 | $32.57 | $8.20 | $(0.60) | $10.05 | $(27.02) | $(21.05) | $1.40 |
| 10 | $104.54 | $64.58 | $20.19 | $(6.86) | $(4.66) | $(1.09) | $(30.30) | $(19.51) | $(5.49) |
| 11 | $61.47 | $38.13 | $13.46 | $(29.70) | $(18.73) | $(12.54) | $(29.18) | $(18.41) | $(12.45) |
| 12 | $69.21 | $43.96 | $14.01 | $(5.07) | $(4.29) | $(2.99) | $(3.44) | $(3.23) | $(2.79) |
| **Annual** | **$1,249.69** | **$779.39** | **$286.08** | **$(135.97)** | **$(120.10)** | **$(25.25)** | **$(337.38)** | **$(243.32)** | **$(71.91)** |
| **mean** | **$104.14** | **$64.95** | **$23.84** | **$(11.33)** | **$(10.01)** | **$(2.10)** | **$(28.11)** | **$(20.28)** | **$(5.99)** |
| **std dev** | **$45.23** | **$28.24** | **$10.18** | **$31.37** | **$19.24** | **$11.26** | **$24.74** | **$15.54** | **$8.81** |

Bills in St. Louis, MO – MISO

*Table 6, Bills in St. Louis, MO – MISO*

| | **Grid** | | | **Solar** | | | **+Battery** | | |
|---|---|---|---|---|---|---|---|---|---|
| **Month** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** |
| 1 | $70.18 | $42.89 | $17.37 | $(4.05) | $(1.56) | $(3.54) | $(1.42) | $0.05 | $(3.06) |
| 2 | $60.98 | $38.17 | $15.44 | $(27.13) | $(17.01) | $(8.80) | $(25.94) | $(16.24) | $(8.70) |
| 3 | $64.37 | $40.38 | $15.66 | $(54.07) | $(35.66) | $(16.75) | $(55.74) | $(36.74) | $(17.26) |
| 4 | $76.96 | $48.51 | $19.86 | $(45.09) | $(31.57) | $(14.13) | $(59.73) | $(40.77) | $(17.76) |
| 5 | $100.67 | $60.80 | $28.31 | $(38.53) | $(26.02) | $(14.35) | $(63.97) | $(39.90) | $(22.30) |
| 6 | $153.91 | $97.29 | $39.60 | $12.24 | $4.61 | $0.56 | $(30.19) | $(22.36) | $(10.10) |
| 7 | $186.34 | $118.00 | $45.48 | $43.22 | $24.93 | $9.03 | $11.26 | $3.90 | $1.11 |
| 8 | $167.46 | $104.13 | $42.21 | $31.01 | $17.90 | $5.88 | $(1.57) | $(3.10) | $(2.82) |
| 9 | $133.58 | $84.77 | $31.24 | $6.92 | $(0.60) | $0.33 | $(28.30) | $(21.78) | $(7.75) |
| 10 | $104.54 | $64.96 | $28.04 | $(2.64) | $(1.28) | $(3.20) | $(26.08) | $(16.49) | $(10.00) |
| 11 | $61.47 | $38.13 | $15.50 | $(14.90) | $(12.06) | $(4.79) | $(14.38) | $(11.75) | $(4.72) |
| 12 | $69.21 | $43.96 | $16.65 | $(0.83) | $(5.17) | $(0.90) | $0.80 | $(4.12) | $(0.66) |
| **Annual** | **$1,249.69** | **$781.97** | **$315.37** | **$(93.86)** | **$(83.50)** | **$(50.66)** | **$(295.27)** | **$(209.30)** | **$(104.01)** |
| **Mean** | **$104.14** | **$65.16** | **$26.28** | **$(7.82)** | **$(6.96)** | **$(4.22)** | **$(24.61)** | **$(17.44)** | **$(8.67)** |
| **std dev** | **$45.23** | **$28.67** | **$11.25** | **$29.72** | **$18.57** | **$8.05** | **$25.06** | **$15.50** | **$7.31** |

Bills in Houston, TX – ERCOT

*Table 7, Bills in Houston, TX – ERCOT*

| | Grid | | | Solar | | | +Battery | | |
|---|---|---|---|---|---|---|---|---|---|
| **Month** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** |
| 1 | $62.35 | $38.36 | $17.91 | $(21.33) | $(16.74) | $(3.67) | $(18.99) | $(15.30) | $(3.07) |
| 2 | $54.18 | $34.13 | $14.50 | $(29.93) | $(16.20) | $(8.75) | $(28.87) | $(15.51) | $(8.55) |
| 3 | $57.19 | $36.12 | $17.81 | $(46.96) | $(28.14) | $(15.80) | $(48.44) | $(29.11) | $(16.30) |
| 4 | $68.37 | $43.33 | $21.29 | $(40.19) | $(27.56) | $(15.19) | $(53.20) | $(35.71) | $(19.20) |
| 5 | $89.44 | $55.10 | $29.18 | $(28.91) | $(19.73) | $(17.91) | $(51.51) | $(32.91) | $(25.91) |
| 6 | $136.74 | $86.42 | $50.54 | $19.22 | $10.00 | $1.75 | $(18.47) | $(13.49) | $(11.56) |
| 7 | $165.55 | $104.16 | $68.89 | $51.88 | $32.04 | $6.54 | $23.48 | $14.62 | $(6.04) |
| 8 | $148.78 | $92.41 | $294.87 | $32.89 | $18.89 | $(75.75) | $3.94 | $0.63 | $(147.97) |
| 9 | $118.68 | $77.19 | $80.47 | $12.56 | $3.70 | $(8.94) | $(18.73) | $(16.37) | $(30.05) |
| 10 | $92.88 | $57.52 | $37.82 | $(12.91) | $(9.53) | $(12.96) | $(33.74) | $(22.72) | $(20.82) |
| 11 | $54.61 | $34.05 | $15.19 | $(32.07) | $(17.36) | $(10.73) | $(31.61) | $(17.08) | $(10.66) |
| 12 | $61.49 | $39.38 | $12.23 | $(12.32) | $(11.01) | $(2.54) | $(10.87) | $(10.06) | $(2.30) |
| **Annual** | **$1,110.26** | **$698.17** | **$660.70** | **$(108.06)** | **$(81.64)** | **$(163.96)** | **$(287.00)** | **$(193.02)** | **$(302.42)** |
| **Mean** | **$92.52** | **$58.18** | **$55.06** | **$(9.01)** | **$(6.80)** | **$(13.66)** | **$(23.92)** | **$(16.09)** | **$(25.20)** |
| **std dev** | **$40.18** | **$25.35** | **$78.80** | **$31.16** | **$18.92** | **$20.90** | **$22.71** | **$13.98** | **$39.64** |

Bills in Houston, TX – MISO

*Table 8, Bills in Houston, TX - MISO*

| | **Grid** | | | **Solar** | | | **+Battery** | | |
|---|---|---|---|---|---|---|---|---|---|
| **Month** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** | **Fixed** | **TOU** | **RTP** |
| 1 | $62.35 | $38.36 | $18.58 | $(21.33) | $(16.74) | $(8.49) | $(18.99) | $(15.30) | $(8.03) |
| 2 | $54.18 | $34.13 | $16.87 | $(29.93) | $(16.20) | $(13.25) | $(28.87) | $(15.51) | $(13.18) |
| 3 | $57.19 | $36.12 | $21.77 | $(46.96) | $(28.14) | $(27.57) | $(48.44) | $(29.11) | $(28.67) |
| 4 | $68.37 | $43.33 | $21.23 | $(40.19) | $(27.56) | $(17.01) | $(53.20) | $(35.71) | $(21.04) |
| 5 | $89.44 | $55.10 | $29.98 | $(28.91) | $(19.73) | $(14.31) | $(51.51) | $(32.91) | $(22.30) |
| 6 | $136.74 | $86.42 | $43.67 | $19.22 | $10.00 | $(0.66) | $(18.47) | $(13.49) | $(12.63) |
| 7 | $165.55 | $104.16 | $52.76 | $51.88 | $32.04 | $14.70 | $23.48 | $14.62 | $5.44 |
| 8 | $148.78 | $92.41 | $49.85 | $32.89 | $18.89 | $4.40 | $3.94 | $0.63 | $(5.30) |
| 9 | $118.68 | $77.19 | $39.76 | $12.56 | $3.70 | $3.62 | $(18.73) | $(16.37) | $(7.53) |
| 10 | $92.88 | $57.52 | $32.79 | $(12.91) | $(9.53) | $(12.59) | $(33.74) | $(22.72) | $(20.65) |
| 11 | $54.61 | $34.05 | $16.74 | $(32.07) | $(17.36) | $(11.69) | $(31.61) | $(17.08) | $(11.60) |
| 12 | $61.49 | $39.38 | $18.52 | $(12.32) | $(11.01) | $(6.79) | $(10.87) | $(10.06) | $(6.54) |
| **Annual** | **$1,110.26** | **$698.17** | **$362.52** | **$(108.06)** | **$(81.64)** | **$(89.64)** | **$(287.00)** | **$(193.02)** | **$(152.03)** |
| **Mean** | **$92.52** | **$58.18** | **$30.21** | **$(9.01)** | **$(6.80)** | **$(7.47)** | **$(23.92)** | **$(16.09)** | **$(12.67)** |
| **std dev** | **$40.18** | **$25.35** | **$13.34** | **$31.16** | **$18.92** | **$11.37** | **$22.71** | **$13.98** | **$9.30** |

**Cross-sectional comparison of Technology and Price Impacts on Net Annual Bills**

*Table 9, Cross-sectional comparison of Technology and Price Impacts on Net Annual Bills*

| | **Grid** | | | **Solar** | | | **+Battery** | | |
|---|---|---|---|---|---|---|---|---|---|
| Annual Bill | Fixed | TOU | RTP | Fixed | TOU | RTP | Fixed | TOU | RTP |
| Fargo MISO | 100% | -37% | -75% | -99% | -101% | -102% | -115% | -111% | -106% |
| Fargo SPP | 100% | -37% | -75% | -99% | -101% | -100% | -115% | -111% | -104% |
| KC SPP | 100% | -38% | -77% | -111% | -110% | -102% | -127% | -119% | -106% |
| STL MISO | 100% | -37% | -75% | -108% | -107% | -104% | -124% | -117% | -108% |
| Houston ERCOT | 100% | -37% | -40% | -110% | -107% | -115% | -126% | -117% | -127% |
| Houston MISO | 100% | -37% | -67% | -110% | -107% | -108% | -126% | -117% | -114% |

**Cross-sectional comparison of Pricing Impacts on Net Annual Bills**

*Table 10, Cross-sectional comparison of Pricing Impacts on Net Annual Bills*

| | **Grid** | | | **Solar** | | | **+Battery** | | |
|---|---|---|---|---|---|---|---|---|---|
| Annual Bill | Fixed | TOU | RTP | Fixed | TOU | RTP | Fixed | TOU | RTP |
| Fargo MISO | 100% | -37% | -75% | 100% | -163% | -280% | 100% | -29% | -62% |
| Fargo SPP | 100% | -37% | -75% | 100% | -163% | -76% | 100% | -29% | -72% |
| KC SPP | 100% | -38% | -77% | 100% | -12% | -81% | 100% | -28% | -79% |
| STL MISO | 100% | -37% | -75% | 100% | -11% | -46% | 100% | -29% | -65% |
| Houston ERCOT | 100% | -37% | -40% | 100% | -24% | -52% | 100% | -33% | -5% |
| Houston MISO | 100% | -37% | -67% | 100% | -24% | -17% | 100% | -33% | -47% |

## SAM configuration options

*Table 11, SAM configuration options*

| | | |
|---|---|---|
| Occupant | 4 | Number of occupants |
| Retrofits | 0 | Energy retrofitted |
| Stories | 2 | Number of stories |
| TCool | 76 | Cooling setpoint |
| THeat | 68 | Heating setpoint |
| YrBuilt | 1980 | Year built |
| en_belpe | 1 | Enable building load estimator |
| en_cool | 1 | Enable electric cooling |
| en_dish | 1 | Enable electric dishwasher |
| en_dry | 1 | Enable electric dryer |
| en_fridge | 1 | Enable electric fridge |
| en_heat | 0 | Enable electric heat |
| en_mels | 1 | misc electric loads |
| en_range | 1 | Enable electric range |
| en_wash | 1 | Enable electric washer |
| floor_area | 2000 | Building floor area |

## Kruskal-Wallis Test – Pricing and Grid Connected Load

### Kruskal-Wallis test that Fixed price, TOU, and RTP have equal loads for grid connected households

*Table 12, Kruskal-Wallis Test – Pricing and Grid Connected Load*

| | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 6.21642707 | 0.0446807 |
| Fargo SPP | 11.0585543 | 0.00396886 |
| KC SPP | 7.43224142 | 0.02432816 |
| STL MISO | 3.50941891 | 0.17295749 |
| Houston ERCOT | 2.66889523 | 0.26330358 |
| Houston MISO | 1.89201356 | 0.38828845 |

**Kruskal-Wallis Test – Pricing and Solar Load**

**Kruskal-Wallis test that Fixed price, TOU, and RTP have equal loads for solar households**

*Table 13, Kruskal-Wallis Test – Pricing and Solar Load*

| | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 1.25944051 | 0.53274081 |
| Fargo SPP | 1.55996501 | 0.45841403 |
| KC SPP | 1.19516015 | 0.55014133 |
| STL MISO | 1.11069585 | 0.57387256 |
| Houston ERCOT | 1.19607338 | 0.54989018 |
| Houston MISO | 0.49678123 | 0.78005518 |

**Kruskal-Wallis Test – Pricing and Solar+Battery Load**

**Kruskal-Wallis test that Fixed price, TOU, and RTP have equal loads for solar+battery households**

*Table 14, Kruskal-Wallis Test – Pricing and Solar+Battery Load*

| | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 1.10320953 | 0.57602468 |
| Fargo SPP | 1.26491034 | 0.5312858 |
| KC SPP | 1.01570465 | 0.60178664 |
| STL MISO | 0.63042926 | 0.72963226 |
| Houston ERCOT | 0.76496307 | 0.68216649 |
| Houston MISO | 0.29483124 | 0.86293525 |

## Kruskal-Wallis Test – Fixed Price and Technology Load

## Kruskal-Wallis test that Fixed price has equal loads for Grid, Solar, and Solar+Battery households

*Table 15, Kruskal-Wallis Test – Fixed Price and Technology Load*

| | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 3616.46339 | 0 |
| Fargo SPP | 3616.46339 | 0 |
| KC SPP | 3576.30609 | 0 |
| STL MISO | 3446.66867 | 0 |
| Houston ERCOT | 4237.17857 | 0 |
| Houston MISO | 4237.17857 | 0 |

## Kruskal-Wallis Test – TOU Price and Technology Load

## Kruskal-Wallis test that TOU price has equal loads for Grid, Solar, and Solar+Battery households

*Table 16, Kruskal-Wallis Test – TOU Price and Technology Load*

| | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 3587.34297 | 0 |
| Fargo SPP | 3587.34297 | 0 |
| KC SPP | 3511.74474 | 0 |
| STL MISO | 3393.31227 | 0 |
| Houston ERCOT | 4196.9712 | 0 |
| Houston MISO | 4196.9712 | 0 |

## Kruskal-Wallis Test – RTP Price and Technology Load

## Kruskal-Wallis test that RTP price has equal loads for Grid, Solar, and Solar+Battery households

*Table 17, Kruskal-Wallis Test – RTP Price and Technology Load*

| | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 3595.62249 | 0 |
| Fargo SPP | 3472.68891 | 0 |
| KC SPP | 3444.51165 | 0 |
| STL MISO | 3425.07007 | 0 |
| Houston ERCOT | 4172.08456 | 0 |
| Houston MISO | 4188.76314 | 0 |

## Kruskal-Wallis Test – Pricing and Grid Connected Bills

## Kruskal-Wallis test that Fixed price, TOU, and RTP have equal monthly bills for grid connected households

*Table 18, Kruskal-Wallis Test – Pricing and Grid Connected Bills*

| | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 23.73574 | 0.00001 |
| Fargo SPP | 23.73574 | 0.00001 |
| KC SPP | 24.97447 | 0.00000 |
| STL MISO | 23.53754 | 0.00001 |
| Houston ERCOT | 10.88889 | 0.00432 |
| Houston MISO | 20.46997 | 0.00004 |

## Kruskal-Wallis Test – Pricing and Solar Bills

## Kruskal-Wallis test that Fixed price, TOU, and RTP have equal monthly bills for solar households

*Table 19, Kruskal-Wallis Test – Pricing and Solar Bills*

| Solar | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 1.85736 | 0.39508 |
| Fargo SPP | 0.95646 | 0.61988 |
| KC SPP | 1.35586 | 0.50767 |
| STL MISO | 0.19069 | 0.90906 |
| Houston ERCOT | 0.50601 | 0.77647 |
| Houston MISO | 1.00450 | 0.60517 |

**Kruskal-Wallis Test – Pricing and Solar+Battery Bills**

**Kruskal-Wallis test that Fixed price, TOU, and RTP have equal monthly bills for solar+battery households**

*Table 20, Kruskal-Wallis Test – Pricing and Solar+Battery Bills*

| | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 0.05856 | 0.97115 |
| Fargo SPP | 0.54505 | 0.76146 |
| KC SPP | 8.28378 | 0.01589 |
| STL MISO | 2.90240 | 0.23429 |
| Houston ERCOT | 1.91141 | 0.38454 |
| Houston MISO | 3.98348 | 0.13646 |

**Kruskal-Wallis Test – Fixed pricing and Technology Bills**

**Kruskal-Wallis test that Fixed price has equal bills for Grid, Solar, and Solar+Battery households**

*Table 21, Kruskal-Wallis Test – Fixed pricing and Technology Bills*

| | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 24.44595 | 0.00000 |
| Fargo SPP | 24.44595 | 0.00000 |
| KC SPP | 23.89339 | 0.00001 |
| STL MISO | 24.07808 | 0.00001 |
| Houston ERCOT | 23.83784 | 0.00001 |
| Houston MISO | 23.83784 | 0.00001 |

**Kruskal-Wallis test – TOU pricing and Technology Bills**

**Kruskal-Wallis test that TOU price has equal bills for Grid, Solar, and Solar+Battery households**

*Table 22, Kruskal-Wallis test – TOU pricing and Technology Bills*

| | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 24.28979 | 0.00001 |
| Fargo SPP | 24.28979 | 0.00001 |
| KC SPP | 23.95195 | 0.00001 |
| STL MISO | 24.14565 | 0.00001 |
| Houston ERCOT | 23.83784 | 0.00001 |
| Houston MISO | 23.83784 | 0.00001 |

**Kruskal-Wallis test – RTP pricing and Technology Bills**

**Kruskal-Wallis test that RTP price has equal bills for Grid, Solar, and Solar+Battery households**

*Table 23, Kruskal-Wallis test – RTP pricing and Technology Bills*

| | Kruskal | p-value |
|---|---|---|
| Fargo MISO | 24.44595 | 0.00000 |
| Fargo SPP | 23.43694 | 0.00001 |
| KC SPP | 22.66216 | 0.00001 |
| STL MISO | 24.01351 | 0.00001 |
| Houston ERCOT | 23.95195 | 0.00001 |
| Houston MISO | 23.64565 | 0.00001 |

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