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Implications of high-penetration renewables for ratepayers and utilities in the residential solar photovoltaic (PV) market

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HIGHLIGHTS

- Optimal solar array size (lowest LCOE) reduces by 20–50% if net metering is removed.
- Batteries are cost-effective without net metering and a price decrease of at least 55%.
- Simulations show "duck curve" behavior for 10,000 homes at various solar PV levels.
- Energy use (kW h) reduces by an equivalent percent increase in solar PV penetration.
- Utility revenue recovery models are evaluated through increased rates and fees.

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ABSTRACT

Residential energy markets in the United States are undergoing rapid change with increasing amounts of solar photovoltaic (PV) systems installed each year. This study examines the combined effect of electric rate structures and local environmental forcings on optimal solar home system size, ratepayer financials, utility financials, and electric grid ramp rate requirements for three urban regions in the United States. Techno-economic analyses are completed for Chicago, Phoenix, and Seattle and the results contrasted to provide both generalizable findings and site-specific findings. Various net metering scenarios and time-of-use rate schedules are investigated to evaluate the optimal solar PV capacity and battery storage in a typical residential home for each locality. The net residential load profile is created for a single home using BEopt and then scaled to assess technical and economic impacts to the utility for a market segment of 10,000 homes modeled in HOMER. Emphasis is given to intraday load profiles, ramp rate requirements, peak capacity requirements, load factor, revenue loss, and revenue recuperation as a function of the number of ratepayers with solar PV. Increases in solar PV penetration reduced the annual system load factor by an equivalent percentage yet had little to no impact on peak power requirements. Ramp rate requirements were largest for Chicago in October, Phoenix in July, and Seattle in January. Net metering on a monthly or annual basis had a negligible impact on optimal solar PV capacity, yet optimal solar PV capacity reduced by 20–50% if net metering was removed altogether. Technical and economic data are generated from simulations with solar penetration up to 100% of homes. For the scenario with 20% homes using solar PV, the utility would need a 16%, 24%, and 8% increase in time-of-use electricity rates ($/kW h) across all ratepayers to recover lost revenue in Chicago, Phoenix, and Seattle, respectively. The $15 monthly connection fee would need to increase by 94%, 228%, or 50% across the same cities if time-of-use electricity rates were to remain unchanged. Batteries were found to be cost-effective in simulations without net metering and at cost reductions of at least 55%. Batteries were not cost-effective—even if they were free—when net metering was in effect. As expected, Phoenix had the most favorable economic scenario for residential solar PV, primarily due to the high solar insolation.

1. Introduction

Addressing the societal demand for low-carbon energy is an ongoing challenge that will persist for several decades. It has been suggested that a zero-carbon economy can be realized in the United States by 2050 through changes in technology, policy, eco-

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nomics, business models, and consumer behavior [1]. Yet that year is far away, and much progress is needed. For now, the increasing amount of research and practice in reducing carbon emissions hint that a zero-carbon future may be possible [2–4].

The long-term vision for carbon-free energy has been pursued with research in renewables design and integration [5,6], grid stability at high levels of renewable penetration [7–11], building energy systems design and analysis [12–14], energy efficiency in end-use devices [15–17], thermal energy storage to offset air conditioning loads [18,19], and studies of the social, political, and economic implications of transitioning to a low-carbon future [20–24]. The diversity of topics covered in the literature is an indication of the complexity and the challenges faced when integrating distributed energy resources (DER) from the individual circuit to the larger grid.

Household solar photovoltaic (PV) systems have become increasingly common in the United States, with a current annual growth rate of 58% [25]. Solar home systems commonly produce excess electricity during the daytime to displace grid purchases during off-sun hours. This excess electricity can be stored in batteries for later use, or credited to the customer through a feed-in tariff or net metering. Net metering is a billing agreement that allows customers to use the credited electricity at another time when solar PV generation is less than the household load. Net metering is a major factor in solar PV adoption [26]. The ability to use the grid as a "zero cost lossless battery" is unquestionably an economic advantage for the consumer (ratepayer). A feed-in tariff is another form of billing agreement [27]. In a feed-in tariff billing agreement, the ratepayer is compensated monetarily for excess production, whereas in net metering the ratepayer receives kilowatt-hour energy credits by "rolling back the meter" during periods of excess production.

The technical and economic implications of small amounts of household solar PV are minimal to the utility, but at higher penetration levels, solar PV is expected to cause grid instability and disrupt utility business models [28]. A primary concern is managing the significant rise in electrical demand that occurs during the late afternoon when solar output declines and residential loads increase as people arrive home from work or school. This increases the ramp rate requirement from dispatchable generation as popularized in the "duck curve" or "duck chart" [29]. Intermittency in renewables is another point of concern when noting that utilities must keep sufficient reserves (e.g., dispatchable generation, storage, and demand response) online to displace potential disruptions in solar PV power output caused by clouding or other effects [28,30]. These issues may become more prevalent over time as distributed solar PV capacity continues to increase.

2. Background

A growing body of research has explored the technical and economic implications of high-penetration distributed residential solar PV [31,26,32–37]. It is clear that the declining costs of solar modules have contributed to increases in the installed capacity of solar PV (EA 2008). Total hardware costs have dropped from \$3.30 per watt to \$1.83 per watt between 2010 and 2012, with current module prices at under \$1.00 per watt [38,39]. Recent work is seeking to reduce costs further by targeting the "soft costs" of solar installation such as labor, supply chain, permitting, and transaction costs. Soft costs comprised approximately two-thirds of the total installed cost of \$5.22 per watt in 2012 [38]. Additional reductions in cost to the end-user were available through tax incentives, subsidies, and rebates offered by governments and utilities [40,37]. Leasing is also an attractive option that offers a no-money-down solution with low financing charges. Current systems can be leased on 20-year or 25-year agreements for as little as \$3.00 per watt to the end-user after accounting for rebates, incentives, financing charges, and maintenance and warranty costs [41,33,42].

The economic advantage of home solar is not universal for all ratepayers. An analysis of local electric rate structures must be performed to determine if solar PV reduces the levelized cost of electricity (LCOE) for the end-user vis-à-vis grid power alone [31,34]. Areas with higher costs of electricity and favorable distributed generation policies—such as Hawaii (USA), Germany, and Denmark—have experienced substantial increases in solar PV penetration whereas regions with lower electricity costs and more strict owner-side generation policies—such as fossil-fuel rich industrialized economies—have seen solar PV penetration grow at a slower rate [43–45]. Net metering has been suggested as one of the leading contributors to the growth of the residential solar PV market [26]. Feed-in tariffs have also contributed to solar PV adoption and often begin with a high feed-in tariff to spur the installation of solar and then reduce the tariff's value over time as a way to slow down the rate of solar PV adoption [34,46,47].

Electric utility business models will not be insolated from the rise in distributed solar PV. Instead, it has been surmised that solar PV consumers will have the strongest effect on utility revenue [36]. According to a scoping study conducted by Lawrence Berkeley National Laboratory, a solar PV penetration rate reducing 10% of retail sales at a Northeast wires-only distribution utility was found to reduce the return on equity by 40% with a corresponding 15% reduction in achieved earnings and an average rate increase of 2.7% for ratepayers [48]. This suggests that the loss of revenue from solar PV customers could be recouped through rate increases for all customers—solar and non-solar homes.

Aside from revenue loss, uncontrolled renewables can create over-production issues within a region when thermal base-loading power plants need to operate at a minimum load or provide reserve capacity [47]. In addition, fluctuations in solar PV output can cause disturbances in voltage and frequency that fatigue hardware and reduce equipment lifetime [49–52]. Further studies are needed to explore these and other challenges of high-penetration solar PV integration [32]. Yet for now, it can be surmised that the unfolding of the residential solar PV market will not continue business as usual for utilities, customers, and technology providers. Modeling approaches and stakeholder engagement efforts that represent, contrast, and integrate the perspectives of various parties can facilitate energy planning decisions for mutual gain [53,54].

This article contrasts the objectives of residential ratepayers and an electric utility by simulating the combined effect of electric rate structures and local environmental forcings on optimal home energy system size, ratepayer financials, and utility technical and financial factors. Analyses are completed of three urban cities (Chicago, Phoenix, and Seattle) in the United States and then contrasted to provide both generalizable findings and site-specific findings. Various time-of-use pricing schedules are investigated, and the effect of net metering is evaluated to determine the optimal capacity of solar PV and battery storage in a typical residential home. The residential load profile is scaled to assess system-wide technical and economic merits of interest to a utility at low-, medium-, and high-penetration solar PV scenarios.

3. Methodological approach

A variety of models are available for evaluating changes in the residential solar PV market. These include elements of expansion planning for modeling system-wide effects of load growth and generation assets, and production cost modeling and economic dispatch for dispatching energy sources to deliver the least cost energy. In this analysis, two software packages were employed: Building Energy Optimization (BEopt) was used to simulate household load profiles for each study location [55,56], and Hybrid Optimization Model for Electric Renewables (HOMER®) [57] was used to aggregate and evaluate system-wide effect of solar PV on the net system load. Finally, sensitivity analyses were performed on hardware cost parameters, solar PV penetration, and utility electricity rates.

BEopt, commonly used to evaluate whole-building energy savings, provides important information about a building, such as size and orientation, materials composition and structure, location, occupancy data, along with a library of technologies for lighting, heating, cooking, and other end-use energy needs. BEopt can be used to describe the costs and benefits of renewable energy options for new or existing residential homes [58,55]. Building energy calculations are completed in an underlying simulation engine, such as EnergyPlus [59]. The computed hourly time series data and aggregate energy use data are reported in BEopt's graphical user interface.

The HOMER software can be used for power system topology selection and sizing against uncertain constraints that are explored through sensitivity analyses on hardware cost, performance, resource availability, and other data used in economic feasibility studies [60–62]. HOMER models a power system using chronological hourly simulations over a one-year period and quantifies the total cost of the power system over its multi-year lifespan. Although HOMER was developed primarily for off-grid micro-grid systems, the software can be used to simulate residential-scale grid-connected systems and model a simplified representation of the electric grid as a single circuit to calculate aggregate load and economic statistics [63]. The latter use case demonstrates the primary role of HOMER in this study.

3.1. Electric load profile and solar irradiance simulation

A residential load profile (without renewables or batteries) was simulated for a household created in BEopt. The selection of a single, common home design subjected to local environmental forcings permits a more direct comparison of results, and therefore generalizable findings, across the case study locations for optimal solar home system size, ratepayer financials, utility financials, and electric grid ramp rate requirements as a function of electric rate structures.

The two-story square home of 11.58 m by 11.58 m (38 feet by 38 feet) equates to a total of 221 square meters (2388 square feet) after subtracting the garage space of 7.62 m by 6.10 m (25 feet by 20 feet) on the first floor (Fig. 1). This home size is within 0.2% of the national average for the United States [64]. Many of the standard industry values listed in the Building America House Simulation Protocols were chosen for simulation [65]. Points of deviation include: gas water heater, gas cooking range, electric clothes dryer, and spacing of 6.10 m (20 feet) between neighboring households. The BEopt model can be reproduced using default values with edits to such values described as deviations from default settings.

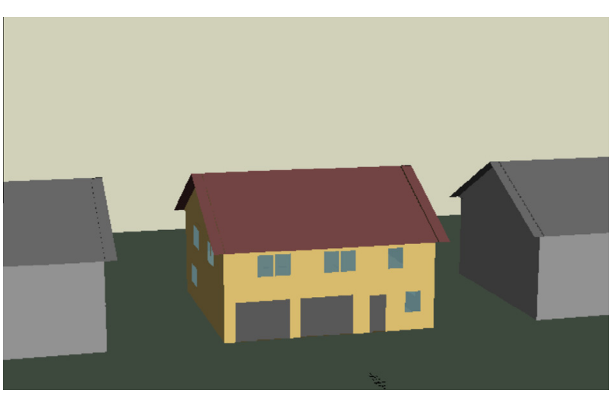

Fig. 1. Household visualization in BEopt.

The BEopt household model was run for three separate locations using BEopt's predefined TMY2 solar and temperature profile data for Chicago, Phoenix, and Seattle [55]. These cities were chosen to provide dataset diversity in location, solar insolation, climate, and weather as shown in Fig. 2 and Table 1. The Chicago metropolitan area, home to 9.7 million people in the midwestern region of the United States, experiences colder winters relative to the other two cities. Seattle is further north in latitude, yet its proximity to the Pacific Ocean in the northwestern region of the country provides more consistent year-round temperatures and milder winters. The 3.7 million people living in the metropolitan area of Seattle have overcast skies for approximately one-quarter to one-third of the year, and consequently receive the least solar insolation of any city. Phoenix has a desert climate and is located in the southwestern United States. The 4.2 million people in the Phoenix metropolitan area experience the greatest solar insolation and hottest temperatures of any study location [56,66]. Fig. 3 summarizes the annual solar profile for all three cities in a heat map of all hours in a one-year period.

Household energy use statistics are summarized in Table 2. It can be seen that Phoenix has a higher peak power demand and average load relative to Chicago and Seattle. This is principally caused by the increase in cooling loads in the warm desert climate. While households in Chicago and Seattle have similar total energy usage, Chicago experiences a higher peak load. The minimum load is similar across all locations, suggesting that non-cooling loads provide similar base load profiles across all regions. This is expected since the BEopt model input parameters were held constant for each study location.

3.2. Household solar PV system sizing and energy costs

Residential load (kW) and global horizontal irradiance (kW/m^2) profiles from the BEopt building energy model were inputted into the HOMER economic model. HOMER includes algorithms to generate synthetic solar data. These algorithms were overridden using hourly data from BEopt to maintain consistency across the two modeling packages. The HOMER model can be reproduced by changing values listed herein away from default values loaded in HOMER.

The DC capacity of the solar array was selected to create a net-zero energy home on an annual basis—the solar array DC capacity was varied until the AC inverter output matched the household AC electricity use, thereby offsetting the total annual energy use for the home so that the net grid in/out was zero. Annual household energy use was taken from BEopt, PV capacity factor from HOMER, and the inverter efficiency assumed a constant 95% in Eq. (1). The maximum allowable PV array capacity was calculated to be 7.57 kW for Chicago, 7.93 kW for Phoenix, and 7.68 kW for Seattle. Solar PV array capacities were similar despite higher loads in Phoenix since the city has a higher solar PV capacity factor.

$$P_{\max} = \frac{E_{tot}}{CF \times \eta_{inv}} \tag{1}$$

$P_{\max}$ = maximum allowable PV array capacity (kW)
CF = capacity factor (%)
E_{tot} = total annual household energy use (kW h/yr)
η_{inv} = inverter efficiency (%)

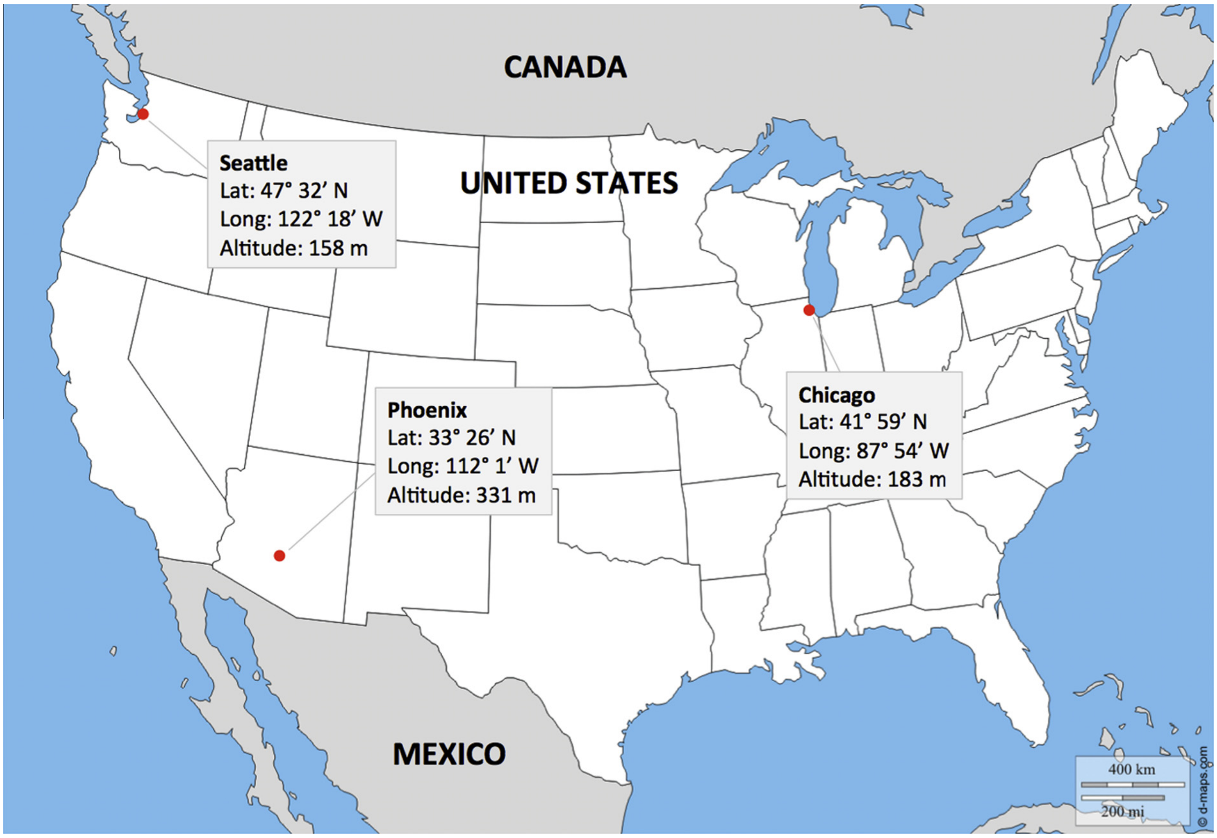

Fig. 2. Geographic data for case study locations [67].

Table 1
Solar and temperature data for case study locations [56].

Location	Average solar insolation (kW h/ m^2/day)	Average daily temperature (°C)	Average daily minimum temperature (°C)	Average daily maximum temperature (°C)
Chicago	3.83	10.0	4.8	14.9
Phoenix	5.71	23.8	17.6	30.1
Seattle	3.31	11.8	8.3	15.6

Net home energy profiles and energy costs were simulated for each study location using the following HOMER input parameters:

- Solar PV—The array was mounted facing due south at a slope equivalent to the latitude in each study site to achieve maximum energy output over a one-year period. Shading and temperature effects were not considered. A conservative derating factor of 80% was selected to account for soiling and line loss, panel degradation, diodes and connections, and other discrepancies between the rated power output and installed power output [68,69]. Rooftop array capacities were evaluated at 5% increments ranging from 0% to 100% of the maximum capacity permitted in each study site. Installed solar PV cost was assumed at $3.00 per watt after rebates and incentives [41,42]. Annual operating and maintenance costs were 1% of the installed system capital cost. Replacement costs were ignored given that the PV system lifetime and simulation timeframe (20 years) were equivalent [70].
- Inverter—The DC-to-AC conversion efficiency was assumed to be a constant 95% through a review of manufacturer specifications from common home solar inverters [71–73]. Inverter sizes were selected to be equivalent to solar PV sizes evaluated in each study site. The initial capital cost and replacement costs incurred for inverter failure were included in the $3.00 per watt cost of the solar home system.
- Battery—A Surrette 4KS25P battery was used with a nominal 7.6 kW h capacity. Costs data included initial costs of $1200, replacement costs of $800, and annual operation and maintenance costs of $40. The effects of battery cost on energy cost and optimal system topology were explored through sensitivity analyses. Battery replacement occurs after reaching a maximum energy throughput as calculated in Eq. (2). HOMER assumes the lifetime of the modeled battery is independent of cycle depth, and uses the annual energy throughput to estimate the battery lifetime, as in Eq. (3).

$$E_{life} = E_{nom}\frac{1}{m}\sum_{i=1}^{m} n_i d_i \quad (2)$$

E_{nom} = nominal capacity of battery (kW h)
E_{life} = lifetime battery throughput (kW h)
m = number of manufacturer data points for lifetime tests (%)
n_i = manufacturer data on number of cycles till failure (–)
d_i = manufacturer data on depth of discharge (%)

$$t_{life} = \frac{E_{life}}{E_{ann}} \quad (3)$$

E_{ann} = annual battery throughput (kW h/yr)
t_{life} = battery lifetime (yr)

- Grid electricity price—Three time-of-use (TOU) rate schedules were selected as shown in Table 3. The price of electricity differed between summer months (June-September) and non-summer months, with peak pricing between 1:00 PM and

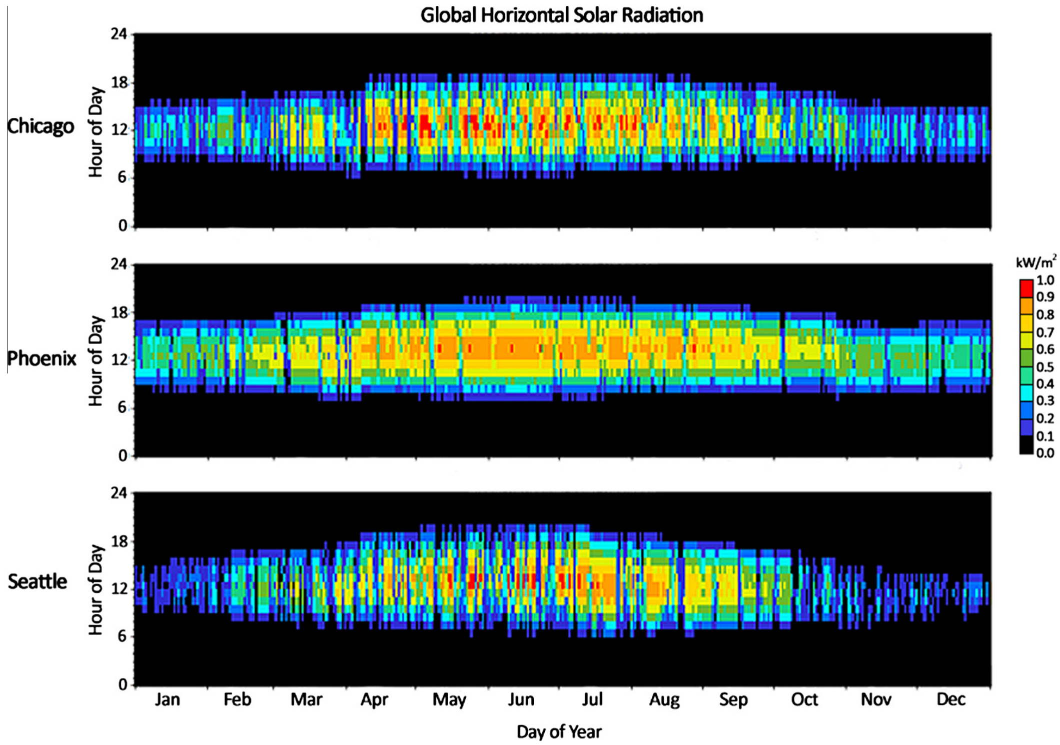

Fig. 3. Hourly global horizontal solar radiation at study locations in BEopt.

Table 2
Household energy use summary.

Location	Average (kW)	Peak (kW)	Min (kW)	Total (kW h)
Chicago	1.00	2.84	0.41	8765
Phoenix	1.57	5.29	0.44	13,750
Seattle	0.90	2.09	0.41	7887

Table 3
Grid rate structures ($/kW h).

Rate period	No TOU	TOU	
	Case 1	Case 2	Case 3
Non-summer	0.12	0.12	0.12
Summer off-peak	0.16	0.16	0.16
Summer on-peak	0.16	0.24	0.32

7:00 PM (weekdays only). Case 1 is the reference case with no intraday TOU price increase, Case 2 represents a 50% TOU increase, and Case 3 represents a 100% TOU increase. Rates in Table 3 include all taxes and fees. A grid connection fee of $15 per month was applied to all scenarios. Although HOMER is not able to evaluate grid price escalation over the simulated 20-year project lifetime, increases in grid price can be modeled implicitly using a negative annual real interest rate and by compensating for that formulation of the time-value of money when selecting equipment replacement costs encumbered over the system's lifetime. This method allowed the study to consider grid rate increases, but did not accurately reflect the time value of money for other operating costs incurred. This was deemed an acceptable simplifying assumption given that operating and maintenance costs for home energy equipment were negligible relative to grid purchases. A grid price escalation of 3.0% per annum was assumed and was based on the observed 3.2% per annum increase in the average retail price of electricity from 2002 to 2015 for residential customers in the United States. It is worth noting that the price of electricity increased 5.0% per annum and 1.7% per annum, between 2002–2008 and 2009–2015, respectively, with a maximum annual increase of 10.1% and minimum annual increase of 0.3% over the observed period of 2002–2015 [74]. It is assumed that future price volatility will be driven by global events, energy policy, the price of natural gas, and new technology. The average increase of 3.0% per annum was considered as representative of the multi-year historical data including such events and input into HOMER as a negative discount rate as discussed previously.

- Net metering—The effect of net metering policy was explored as follows: (a) no net metering, (b) net metering calculated on a monthly basis, and (c) net metering calculated on an annual basis. A flat sell-back rate of $0.03/kW h was applied across all scenarios to reflect the sale of any net excess generation from the household PV array at the end of a net metering period. This rate approximates a typical wholesale electricity value in the United States [75].

Optimal array capacities that produce least-cost energy for the consumer were evaluated using the LCOE formulation (Eq. (4)) from HOMER, which discounts future energy use at the same rate as cash flow terms.

$$LCOE = \frac{\sum_{t=0}^{n} \frac{C_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+i)^t}} \tag{4}$$

$LCOE$ = levelized cost of energy ($/kW h)
t = increment of time (yr)
n = lifetime of the system (yr)
i = discount rate (%)
C_t = net cash flow in year t ($)
E_t = useful energy provided in year t (kW h)

3.3. Aggregate utility-scale effects

Utility-scale effects of solar PV were investigated by calculating the net system-wide load profile as a summation of 10,000 individual homes. The number of homes selected does not affect conclusions of the study achieved on a *relative* basis with respect to input parameters when noting the linear scaling in Eqs. (1) and (5). Stated otherwise, the same relative findings emphasized in this comparative study can be achieved by simulating 100 homes or 500,000 homes. The quantity of 10,000 homes is a small subset of homes in each city, yet is large enough to illustrate 5–50 MW swings in utility net load that affect the output of committed assets and still sufficiently small to have no effect or minor effect on utility unit commitment decisions and transmission scheduling to a metropolitan area.

The net load profile was calculated for various levels of PV penetration using the affine combination given in Eq. (5). Households with solar PV used the maximum allowable solar PV capacity calculated from Eq. (1).

$$P_{utility} = n_h[(1-\gamma)P_{res} + \gamma P_{res,PV}] \tag{5}$$

$P_{utility}$ = utility net power (kW)
P_{res} = net power of a household without PV installed (kW)
$P_{res,PV}$ = net power of a household with PV installed (kW)
n_h = number of households simulated (–)
γ = residential PV adoption rate (%)

4. Results and analysis

Hourly time series data were generated for a one-year period in each simulation. Data was selected from January, April, July, and October to visualize effects to the net system load profile over various parts of the year.

4.1. Utility implications

Implications of solar PV for utilities were first explored by examining the net system load profile and economic metrics for residential PV penetration rates of 0%, 5%, 10%, 15%, 20%, and 25%. This utility-focused analysis assumed that ratepayers install sufficient solar PV to make their home net-zero.

Simulation results for net load profiles exhibit "duck curve" behavior at higher solar PV penetrations that differ by location and season. Fig. 4 shows the average daily load profile for selected months in the year with these findings easily identifiable based on location, time of day, and time of year. It can be seen that net load profiles overlap in the early and late hours of the day due to a lack of sunlight, as expected. The effect of solar PV on the net profile is clearly the greatest in Phoenix, yet Phoenix displays no negative net load in July due to the high use of electric air conditioning units. Chicago and Seattle, conversely, experience the greatest drop in net load in July, given a reduced air conditioning load when compared to Phoenix. The minimum annual net load for Chicago and Seattle occurs in April and July, respectively, due to their slightly higher cooling load requirements in the summer. The minimum annual net load for Phoenix occurs in April due to its high solar insolation and relatively minimal cooling load, when compared to July at the same location. The dynamics of the net load profile clearly vary by season, indicating that a utility must adapt operational strategies throughout the year to handle additional ramp rate requirements.

Fig. 4 depicts the time of day when the maximum ramp rate occurs. The maximum positive ramp rate occurred at 4:00 PM or 5:00 PM in almost all scenarios. Exceptions are Chicago and Seattle in April (7:00 PM) and Phoenix and Seattle in October (6:00 AM). The morning peak in October is smaller in magnitude than the evening peak, yet larger ramp rates occur in the morning. Table 4 summarizes the ramp rates quantitatively across various solar PV penetration rates and provides the percentage change compared to the no-solar (0% penetration) scenario. The largest ramp rates occurred during January (winter) for Chicago and Seattle for the no-solar reference case. This is considered an artifact of the simulated household load data with lighting loads turning on earlier in the day during the winter months. However, the no-solar reference case for Phoenix exhibited higher ramp rates in July (summer) when cooling loads are peaking.

A clear trend exists between the maximum ramp rate and solar PV penetration rate—an increase in residential solar PV causes an increase in utility ramp rate requirements. An exception occurs during October when the ramp rate requirements decline and shift from morning to evening. These ramp rate reductions were minimal and only occurred for the 5% and 10% solar penetration scenarios in October of the months shown for Phoenix and Seattle. This behavior discontinued as solar PV penetration reached 15% and exhibited positive changes in the maximum ramp rate.

Ramp rates requirements over the year were affected differently by the solar PV penetration rate. The relative change in the ramp rate magnitude was greatest for Phoenix in January and greatest for Chicago and Seattle in July. This is an important finding for scheduling peaker plants that are not typically online and ready to provide power within existing grid networks with lower solar PV penetration rates. As expected, ramp rate characteristics for Chicago and Seattle are fairly similar, on an average daily basis, using the household energy model evaluated in each location with similar environmental forcings.

Seasonal ramp rate values in Table 4 are complemented by additional metrics in Table 5 including the average system load, peak system load, minimum system load, maximum ramp rate, total energy usage, and load factor over the entire year. Increased PV penetration had a strong effect on all metrics—except peak system load—across the study locations. Solar PV penetration had a negligible effect on peak system load in Seattle and exhibited a minor decrease in the peak load observed in Chicago and Phoenix. The relative change in the ramp rate was another point of departure across study locations. The change in ramp rate for Chicago and Seattle was approximately twice that of Phoenix. This suggests that Phoenix already exhibits high ramp rates due to existing peaks in the load profile—a point corroborated by the lower load factor (higher peak power relative to average power) across all simulations for Phoenix. These data provide further evidence that utilities may need to place more dispatchable resources online to accommodate higher ramp rate requirements caused by increases in distributed renewables. Such dispatchable generation could include peaker plants, storage, demand response, or other controllable assets.

Table 6 provides financial metrics to consider alongside the technical metrics in Table 5. Changes in utility annual revenue are given for various solar PV penetration rates and TOU rate structures. Data in the table was selected for simulations using monthly net metering, common for residential net metering agreements. As expected, increases in PV penetration decrease utility revenue. Utility revenue dropped 0.88–1.04% for every one-percent increase in PV penetration. However, increases in the on-peak price of electricity had little to no effect on the relative change in utility revenue across solar PV penetration rates. The smaller change in utility revenue for Phoenix is explained by the greater amount of net-negative months in Phoenix relative to the other two cities—each additional kW h generated in net-negative months yields revenue loss equivalent to the sell-back rate ($0.03/kW h) whereas in net-positive months an additional kW h of generation yields revenue loss equivalent to the TOU electric rate.

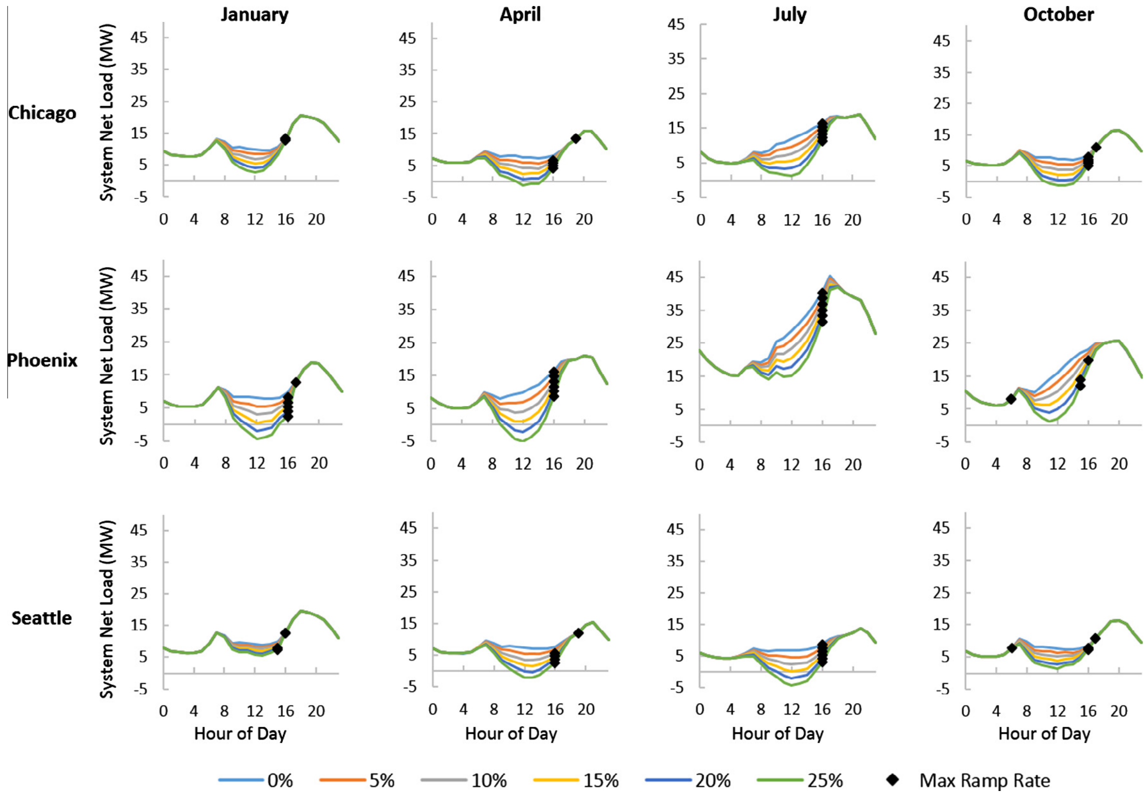

Fig. 4. Grid load profiles at various solar PV penetration rates with net-zero solar PV capacity for the ratepayer.

4.2. Ratepayer implications

This analysis assumed that ratepayers are rational agents seeking to minimize their energy expenditures by selecting the least-cost energy source. The optimal home energy system provided the lowest LCOE for the ratepayer. Solar PV system capacities were evaluated from 0% (no solar) to 100% (net-zero home) in 5% increments. The analysis was repeated under various net metering agreements (monthly, annually, none) and three TOU rate structures (Table 3). Fig. 5 provides a graph of the LCOE for each simulation completed. The minima shown in Fig. 5—lowest LCOE for the ratepayer—are also given in Table 7. There is a clear difference in the optimal PV capacity by location and net metering policy.

Larger solar home systems were economical in Phoenix due to excellent solar insolation. Optimal array sizes in Chicago and Seattle were smaller, with solar providing minimal financial benefit to the ratepayer in cases where there is no net metering.

Simulations with net metering on a monthly or annual basis had the same effect on LCOE and hence the optimal solar array capacity, indicating that ratepayers can size their solar PV system regardless of whether net metering occurs on a monthly or annual timeframe. It is clear, however, that completely removing net metering reduces the optimal array capacity appreciably. Optimal array capacities reduced by 20–50% when net metering was removed because the value of excess solar is credited to the ratepayer at the comparatively low sell-back rate of \$0.03/kW h. An interesting finding is that Phoenix had a relatively flat LCOE curve in the absence of net metering, suggesting that ratepayers could size a solar PV system with little consideration for the magnitude of financial gain or loss.

Ratepayers can select the solar PV system size with minimal consideration for the specific TOU rate schedule when noting the minor effect of TOU peak rate on optimal array capacity. TOU pricing curves converge at higher PV capacities because solar PV costs contribute to a larger portion of total costs.

An analysis of solar-storage systems indicated that batteries were not cost-effective under present grid rate structures and equipment prices. Fig. 6 provides a graphical representation of the analysis showing the optimal system type—set of power system components with least cost energy—indicated by shaded regions on the sensitivity graph. TOU peak prices are shown on the y-axis and battery prices on the x-axis at 0–100% of battery cost. Batteries were only cost-effective in cases without net metering, at a high on-peak grid price, and at a greatly reduced battery cost (>55%). Batteries were never cost-effective in cases when net metering was in effect (monthly or annually). This is expected since ratepayers can use the grid as a "zero cost lossless battery" under a net metering agreement. Cycling grid power through a battery increases the cost of energy discharged (Eq. (6)), suggesting that a battery may not be cost-effective for dispatch purposes even if the battery is free. In scenarios with higher on-peak grid prices, a battery can be useful for storing low-cost energy from off-peak times and discharging the energy during higher on-peak times. Batteries had the most favorable business case in Phoenix because solar PV could not fully meet electricity loads during summer peak hours. However, the value of storage could increase if other ancillary benefits such as backup power or power quality control are considered and monetized.

$$C_{e,o} = \frac{C_{e,i}}{\eta_{bat}\eta_{inv}\eta_{rec}} \tag{6}$$

$C_{e,o}$ = cost of AC grid energy taken from the battery (\$/kW h)
$C_{e,i}$ = cost of AC grid energy put into the battery (\$/kW h)
η_{bat} = battery efficiency (%)
η_{inv} = inverter efficiency (%)
η_{rec} = rectifier efficiency (%)

Table 4
Maximum system ramp rate evaluated at various solar PV penetration rates with net-zero solar PV capacity for the ratepayer.

Month	Homes with PV (%)	Ramp Rate Magnitude [MW/h] (Change in Magnitude Relative to Reference Case of 0% Homes with Solar [%])		
		Chicago	Phoenix	Seattle
January	0	4.57 (-)†	3.87 (-)‡	4.41 (-)†
	5	4.66 (2%)†	4.60 (19%)†	4.42 (0%)†
	10	4.75 (4%)†	5.96 (54%)†	4.44 (1%)†
	15	4.84 (6%)†	7.31 (89%)†	4.46 (1%)†
	20	4.93 (8%)†	8.66 (124%)†	4.53 (3%)**
	25	5.02 (10%)†	10.2 (159%)†	5.03 (14%)**
April	0	2.42 (-)§	3.02 (-)†	2.45 (-)§
	5	2.42 (0%)§	3.81 (26%)†	2.45 (0%)§
	10	2.77 (14%)†	4.61 (53%)†	2.56 (5%)†
	15	3.33 (38%)†	5.40 (79%)†	3.12 (28%)†
	20	3.89 (61%)†	6.20 (105%)†	3.69 (51%)†
	25	4.45 (84%)†	6.99 (132%)†	4.25 (74%)†
July	0	1.93 (-)†	5.13 (-)†	1.74 (-)†
	5	2.52 (31%)†	6.02 (17%)†	2.29 (32%)†
	10	3.12 (62%)†	6.91 (35%)†	2.85 (64%)†
	15	3.71 (92%)†	7.80 (52%)†	3.40 (96%)†
	20	4.30 (123%)†	8.69 (69%)†	3.96 (128%)†
	25	4.90 (154%)†	9.58 (87%)†	4.51 (160%)†
October	0	2.99 (-)‡	3.49 (-)*	2.95 (-)*
	5	3.21 (7%)†	3.39 (-3%)*	2.83 (-4%)‡
	10	3.86 (29%)†	3.28 (-6%)*	2.84 (-4%)‡
	15	4.52 (51%)†	3.92 (12%)†	3.08 (5%)†
	20	5.18 (73%)†	4.60 (32%)**	3.34 (13%)†
	25	5.84 (95%)†	5.47 (57%)**	3.59 (22%)†

Note: Ramp rate time of day denoted by * 6:00 AM, ** 3:00 PM, † 4:00PM, ‡ 5:00PM, § 7:00PM

0-49%	50-99%	100-149%	150%+	Negative

Table 5
Annual technical metrics at various solar PV penetration rates with net-zero solar PV capacity for the ratepayer.

Location	Metrics	Solar PV penetration (change relative to reference case of 0% solar [%])					
		0%	5%	10%	15%	20%	25%
Chicago	Average (MW)	10.0 (–)	9.5 (–5%)	9.0 (–10%)	8.5 (–15%)	8.0 (–20%)	7.5 (–25%)
	Peak (MW)	28.4 (–)	28.0 (–1%)	27.6 (–3%)	27.2 (–4%)	26.8 (–6%)	26.5 (–7%)
	Min (MW)	4.1 (–)	1.4 (–65%)	–1.3 (–132%)	–4.1 (–199%)	–6.8 (–266%)	–9.6 (–333%)
	Total (GW h)	87.7 (–)	83.3 (–5%)	78.9 (–10%)	74.5 (–15%)	70.1 (–20%)	65.7 (–25%)
	Ramp rate (MW/h)	4.8 (–)	5.1 (6%)	5.6 (17%)	6.8 (41%)	9.0 (88%)	11.3 (134%)
	Load factor	0.35 (–)	0.34 (–4%)	0.33 (–7%)	0.31 (–11%)	0.30 (–15%)	0.28 (–20%)
Phoenix	Average (MW)	15.7 (–)	14.9 (–5%)	14.1 (–10%)	13.3 (–15%)	12.6 (–20%)	11.8 (–25%)
	Peak (MW)	52.9 (–)	52.1 (–2%)	51.2 (–3%)	51.0 (–4%)	50.9 (–4%)	50.8 (–4%)
	Min (MW)	4.4 (–)	2.7 (–39%)	–0.2 (–106%)	–3.2 (–172%)	–6.5 (–248%)	–9.9 (–324%)
	Total (GW h)	137.5 (–)	130.6 (–5%)	123.7 (–10%)	116.9 (–15%)	110.0 (–20%)	103.1 (–25%)
	Ramp rate (MW/h)	7.3 (–)	8.4 (15%)	9.5 (30%)	10.5 (45%)	11.6 (60%)	12.7 (75%)
	Load factor	0.30 (–)	0.29 (–4%)	0.30 (–7%)	0.26 (–12%)	0.25 (–17%)	0.23 (–22%)
Seattle	Average (MW)	9.0 (–)	8.6 (–5%)	8.1 (–10%)	7.7 (–15%)	7.2 (–20%)	6.8 (–25%)
	Peak (MW)	20.9 (–)	20.9 (0%)	20.9 (0%)	20.9 (0%)	20.9 (0%)	20.9 (0%)
	Min (MW)	4.1 (–)	1.3 (–67%)	–1.5 (–136%)	–4.3 (–206%)	–7.2 (–275%)	–10.0 (–344%)
	Total (GW h)	78.9 (–)	74.9 (–5%)	71.0 (–10%)	67.0 (–15%)	63.1 (–20%)	59.1 (–25%)
	Ramp rate (MW/h)	4.7 (–)	5.5 (18%)	7.2 (55%)	8.9 (92%)	10.6 (129%)	13.2 (184%)
	Load factor	0.43 (–)	0.41 (–5%)	0.39 (–10%)	0.37 (–15%)	0.34 (–20%)	0.32 (–25%)

Table 6
Annual utility revenue at various solar PV penetration rates with net-zero solar PV capacity for the ratepayer.

Location	On-peak price ($/kW h)	Utility revenue [$ 000,000/yr] (change relative to reference case of 0% solar [%])					
		0%	5%	10%	15%	20%	25%
Chicago	0.16	13.4 (–)	12.8 (−4%)	12.2 (−9%)	11.6 (−13%)	11.0 (−18%)	10.4 (−22%)
	0.24	14.1 (–)	13.5 (−5%)	12.8 (−9%)	12.1 (−14%)	11.5 (−19%)	10.8 (−23%)
	0.32	14.8 (–)	14.1 (−5%)	13.4 (−10%)	12.6 (−15%)	11.9 (−20%)	11.2 (−24%)
Phoenix	0.16	21.2 (–)	20.2 (−4%)	19.3 (−9%)	18.4 (−13%)	17.5 (−17%)	16.5 (−22%)
	0.24	23.1 (–)	22.1 (−4%)	21.1 (−9%)	20.1 (−13%)	19.0 (−18%)	18.0 (−22%)
	0.32	25.1 (–)	24.0 (−4%)	22.9 (−9%)	21.7 (−13%)	20.6 (−18%)	19.5 (−22%)
Seattle	0.16	12.2 (–)	11.6 (−5%)	11.1 (−9%)	10.5 (−14%)	10.0 (−18%)	9.4 (−23%)
	0.24	12.6 (–)	12.0 (−5%)	11.4 (−10%)	10.8 (−15%)	10.2 (−19%)	9.5 (−24%)
	0.32	13.1 (–)	12.4 (−5%)	11.7 (−10%)	11.0 (−16%)	10.4 (−21%)	9.7 (−26%)

4.3. Combined analysis

The utility analysis with net-zero homes was reevaluated using optimal solar array capacities for each study location. This scenario explores solar PV penetration rates up to 100% by assuming the decision to install solar PV lies solely in the hands of the ratepayer. In specific terms, utilities and policy makers have no direct authority or control over ratepayer choice and therefore ratepayers have the freedom to install any amount of PV and batteries. A second assumption is that ratepayers make decisions to minimize energy expenditures when selecting home energy system size. The least-cost optimal solar PV array capacities were used for the 0.24 $/kW h case—65% for Chicago, 100% for Phoenix, 35% for Seattle. Batteries were not cost-effective and were therefore not considered. Monthly net metering was applied.

The duck curves in Fig. 7 have similar profiles to those in Fig. 4, yet are more prominent at higher solar PV penetration rates. As expected, the duck curve behavior is more pronounced in areas with higher installed solar PV capacity—Phoenix, Chicago, and then Seattle. Ramp rate data by month is provided in Table 8. It is again noted that the largest ramp rates for Phoenix occur in January (winter), suggesting that high air conditioning loads in July (summer) offset the high solar insolation. The visible difference in Seattle's net load profiles between January and July illustrates the discrepancy in solar insolation received between the winter and summer months, respectively. Chicago has the most consistent

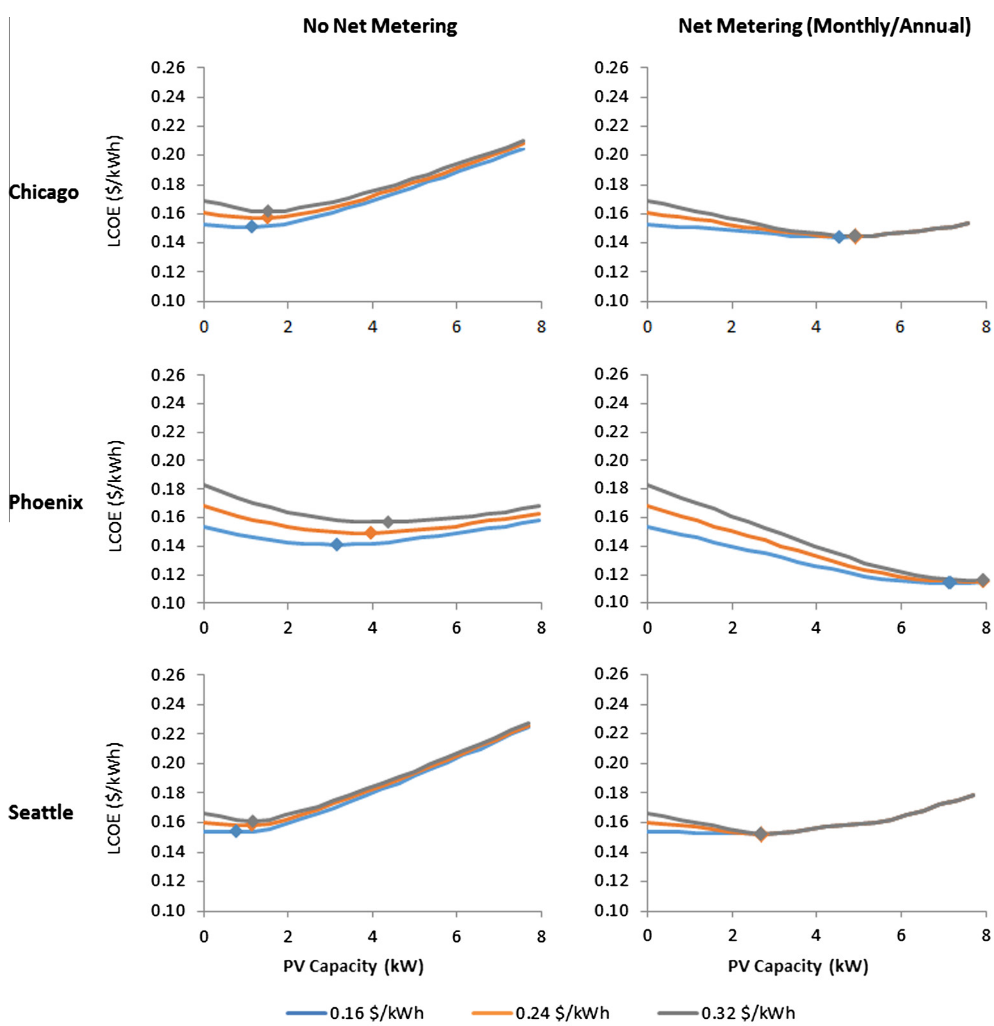

Fig. 5. Levelized cost of energy for solar PV systems under various rate structures.

Table 7
Optimal solar PV array capacities for the ratepayer.

Location	Peak price ($/kW h)	Optimal PV capacity [kW] (relative to net-zero home solar PV capacity [%])	
		No net metering	Net metering (Monthly/Annually)
Chicago	0.16	1.14 (15%)	4.54 (60%)
	0.24	1.51 (20%)	4.92 (65%)
	0.32	1.51 (20%)	4.92 (65%)
Phoenix	0.16	3.17 (40%)	7.14 (90%)
	0.24	3.97 (50%)	7.93 (100%)
	0.32	4.36 (55%)	7.93 (100%)
Seattle	0.16	0.77 (10%)	2.69 (35%)
	0.24	1.15 (15%)	2.69 (35%)
	0.32	1.15 (15%)	2.69 (35%)

net load profile across the year with minimal difference in its peak and minimum loads in the observed months. Fig. 8 summarizes these and other metrics for each location. Solar PV adoption rate had little effect on peak power yet produced a steady negative trend in the average power and hence the load factor. For Phoenix, the 100% solar PV adoption rate yielded a 100% reduction in the average power and load factor—making each equivalent to zero—because the optimal solar array capacity for Phoenix produced a net-zero energy home.

Utility revenue loss summarized in Table 9 displays a fairly steady negative trend with respect to solar penetration for each location. This trend becomes weaker for Phoenix at higher solar PV penetration rates because the fixed monthly connection fee comprises a larger percentage of total annual revenue.

Table 10 lists the requisite increase in electric rates to recover the revenue losses reported in Table 9. Rate increases were applied to all customers and applied evenly across each rate period (non-summer, summer off-peak, and summer on-peak). To take an example, if 20% of homes install solar PV under a 0.24 $/kW h peak power price, the utility would need a 16%, 24%, and 8% increase in rates across all ratepayers to recover lost revenue in Chicago, Phoenix, and Seattle, respectively. These rises in electric rates were a

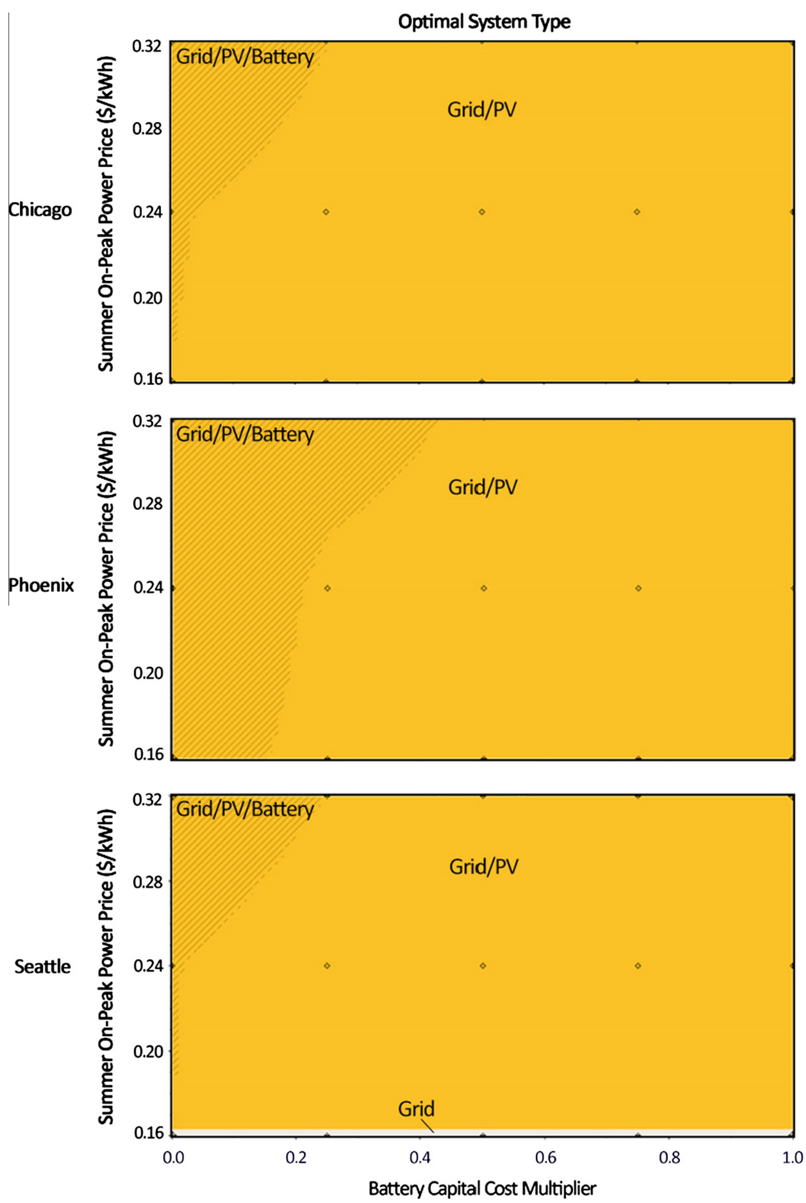

Fig. 6. Least-cost solar-storage power system configurations without net metering.

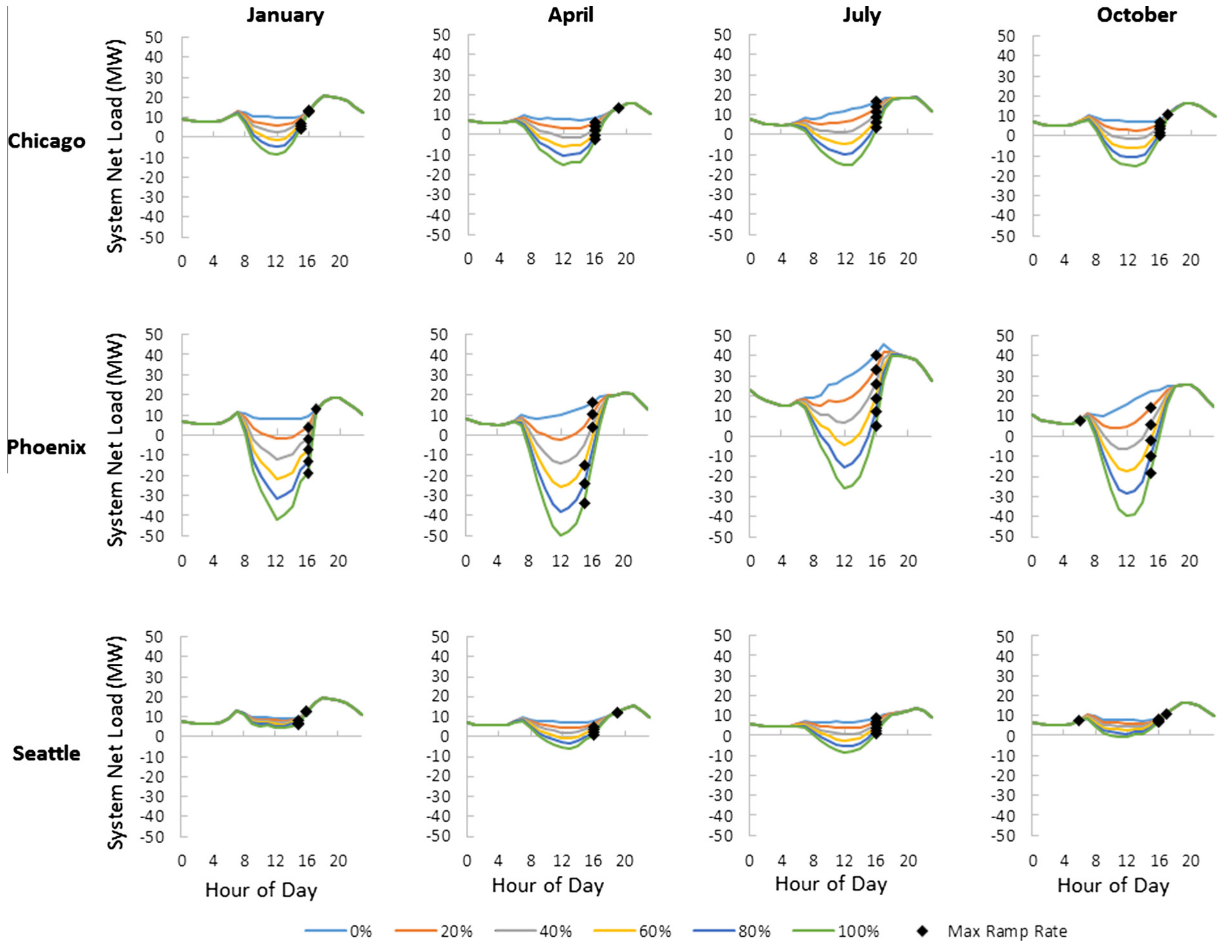

Fig. 7. Grid load profiles at various solar PV penetration rates with optimal solar PV capacity for the ratepayer.

quadratic function of the solar PV penetration rate because a kW h generated by the ratepayer has a doubling effect on utility revenue when net metering is in effect—one kW h of lost revenue plus one kW h credit to ratepayer per one kW h generated by home solar. It is important to note that these results only consider revenue loss and do not consider potential cost savings associated with a reduction in utility operating expenses.

Table 11 shows results from a complementary analysis using the monthly connection fee to recover lost revenue. Showing results for the selected penetration rate of 20%, a utility would need to increase the base connection fee of $15.00 per month to an average of $29.17, $49.17, and $22.50 per month for Chicago, Phoenix, and Seattle, respectively. Phoenix requires the greatest rise in the monthly connection fee based on the fact that homes in Phoenix have larger solar arrays relative to Chicago and Seattle. If the connection fee increase were applied to solar customers only, the resulting connection fee would equate to an average of $85.83, $185.83, and $52.50 per month for Chicago, Phoenix, and Seattle, respectively. Looking further at the Phoenix scenario with 20% solar PV market penetration, the utility would need to increase the connection fee by 228% for all customers or 1139% for solar customers, which is an average fee increase of 11.39% and 56.94% for each one-percent rise in solar PV penetration, respectively.

5. Discussion and conclusions

This study examined the implications of high penetration solar PV systems in the residential market across three cities in the United States by exploring the combined effect of electric rate structures and local environmental forcings on optimal solar home system size, ratepayer financials, utility financials, and net electric loads. The analyses first considered net-zero energy homes with solar capacities equated at 7.57 kW for Chicago, 7.93 kW for Phoenix, and 7.68 kW for Seattle, with utility metric calculations that included ramp rate requirements, intraday load profiles, load factor, and revenue loss with solar PV penetration rates up to 25%. Retail electricity sales (kW h) dropped by approximately 1% for each 1% increase in solar PV penetration. This is comparable to the loss of sales reported in other studies and provides further evidence that new rate structures with revenue decoupling should be developed and piloted [48]. This analysis was repeated for each location using the optimal array capacity that provided the minimum LCOE for the ratepayer with installed capacities of 4.92 kW for Chicago, 7.93 kW for Phoenix, and 2.69 kW for Seattle with solar PV penetration rates up to 100%. Some of the major findings include:

- Net metering had a significant effect on the optimal amount of solar PV installed. Removing net metering decreased solar array capacities by 20–50% when selecting the optimal capacity by the lowest LCOE. Monthly and annual net metering simulations yielded the same optimal solar PV sizing.
- Optimal solar PV array capacities were unchanged or increased slightly (0–15%) at higher TOU rates (50–100%). The optimal capacity may increase further if solar panel orientation is not due south; other studies have reported economic gains of 3–4% for panels facing 30 degrees west of due south [52].

Table 8
Maximum system ramp rate evaluated at various solar PV penetration rates with optimal solar PV capacity for the ratepayer.

Month	Homes with PV (%)	Ramp Rate Magnitude [MW/h] (Change in Magnitude Relative to Reference Case of 0% Homes with Solar [%]) Chicago	Phoenix	Seattle
January	0	4.57 (-)†	3.87 (-)‡	4.41 (-)†
	20	4.80 (5%)†	8.66 (124%)†	4.43 (1%)†
	40	5.04 (10%)†	14.08 (264%)†	4.45 (1%)†
	60	5.70 (25%)**	19.49 (404%)†	4.63 (5%)**
	80	6.73 (47%)**	24.90 (543%)†	5.33 (21%)**
	100	7.76 (70%)**	30.27 (682%)†	6.02 (37%)**
April	0	2.42 (-)§	3.02 (-)†	2.45 (-)§
	20	3.10 (29%)†	6.20 (105%)†	2.45 (0%)§
	40	4.56 (89%)†	9.38 (211%)†	3.01 (23%)†
	60	6.02 (149%)†	12.70 (321%)**	3.80 (55%)†
	80	7.48 (210%)†	16.22 (437%)**	4.59 (88%)†
	100	8.94 (270%)†	19.70 (553%)**	5.38 (120%)†
July	0	1.93 (0%)†	5.13 (-)†	1.74 (-)†
	20	3.47 (80%)†	8.70 (69%)†	2.52 (45%)†
	40	5.02 (160%)†	12.26 (139%)†	3.29 (89%)†
	60	6.56 (240%)†	15.82 (208%)†	4.07 (134%)†
	80	8.10 (320%)†	19.38 (278%)†	4.85 (179%)†
	100	9.65 (400%)†	22.91 (346%)†	5.62 (224%)†
October	0	2.99 (0%)‡	3.50 (-)*	2.95 (-)*
	20	4.26 (42%)†	4.61 (32%)**	2.84 (-4%)‡
	40	5.97 (100%)†	8.09 (131%)**	3.03 (3%)†
	60	7.68 (157%)†	11.57 (231%)**	3.39 (15%)†
	80	9.39 (214%)†	15.05 (330%)**	3.74 (27%)†
	100	11.10 (271%)†	18.50 (429%)**	4.09 (39%)†

Note: Ramp rate time of day denoted by * 6:00 AM, ** 3:00 PM, † 4:00PM, ‡ 5:00PM, § 7:00PM

0-49%	50-99%	100-199%	200%+	Negative

- Batteries were not cost-effective—even if they were free—when net metering was in effect. Batteries were found to be cost-effective in simulations without net metering and at cost reductions of at least 55%. This decrease in consumer purchase price could be achieved through subsidies that improve home storage economics. Findings corroborate other studies, i.e., the requisite size of subsidies to reach break-even will decrease as grid electricity prices increase [40]. Further, ancillary benefits of storage may improve economics beyond a pure consumer-focused analysis [28,30].
- Intraday load profiles with "duck curve" behavior were more prominent as solar PV penetration rates increased. The largest ramp rates for each location occurred in the late afternoon as solar insolation decreased and occupancy loads increased with residents returning home from work or school.
- Increases in the solar PV penetration rate changed the time of year in which the maximum ramp rate was observed: July to January for Phoenix, January to October for Chicago, with no change for Seattle.
- Utility revenue loss can be recovered by increasing the electricity rate ($/kW h) or the fixed monthly connection fee ($ per month). Taking Phoenix as an example with 20% solar penetration and 0.24 $/kW h peak power price, a utility would need to increase electricity rates by 24% or increase the fixed connection by 228% ($15.00 per month to $49.17 per month) across all residential ratepayers to recoup lost revenue if 20% of homes in the region installed solar PV. The connection fee would need to be raised by 1139% ($15.00 per month to $185.83 per month) if revenue was recovered from only the solar customers. Other revenue generation options include demand charges or energy-as-a-service business models.

These site-specific findings emphasize the interplay between technical, economic, and policy considerations within the context of local environmental forcings, energy use behaviors, and grid rate structures. Pertinent generalizable findings to other study locations include:

- Solar PV penetration had little effect on peak power draw.
- There was little observed difference between monthly and annual net metering.
- Net metering was shown to negate the cost-effectiveness of batteries under the modeled parameters. The grid can be effectively characterized as a "zero cost lossless battery" with both technical and economic advantages over battery storage if used for energy management alone.
- Utilities may need to place more dispatchable resources online to accommodate higher ramp rate requirements caused by increases in distributed renewables. Such dispatchable generation could include peaker plants, storage, demand response, or

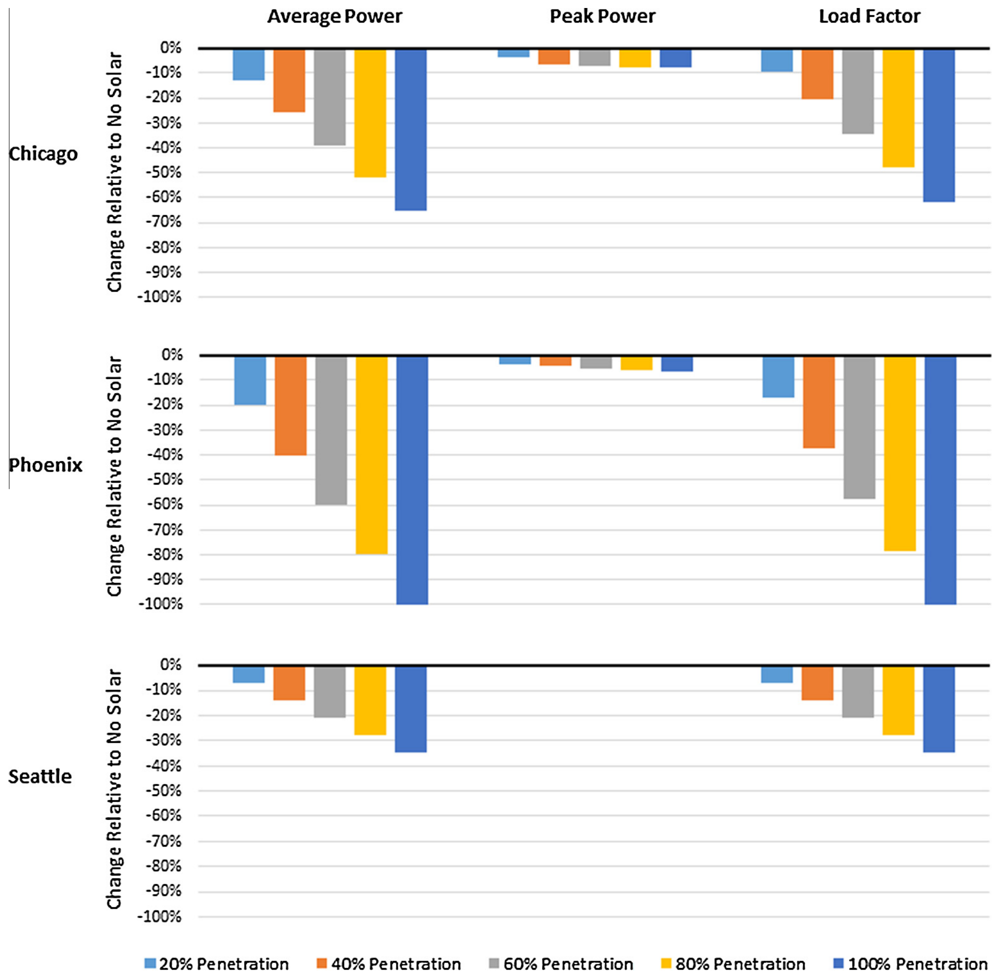

Fig. 8. Change in grid metrics at various solar PV penetration rates with optimal solar PV capacity for the ratepayer.

Table 9
Annual utility revenue at various solar PV penetration rates with optimal solar PV capacity for the ratepayer.

Location	On-peak price ($/kW h)	Utility revenue [$ 000,000/yr] (change relative to reference case of 0% solar [%])					
		0%	20%	40%	60%	80%	100%
Chicago	0.16	13.4 (–)	11.9 (−12%)	10.3 (−23%)	8.8 (−35%)	7.3 (−46%)	5.9 (−56%)
	0.24	14.1 (–)	12.4 (−12%)	10.7 (−24%)	9.0 (−37%)	7.3 (−48%)	5.9 (−58%)
	0.32	14.8 (–)	12.9 (−13%)	11.0 (−26%)	9.2 (−38%)	7.4 (−50%)	5.9 (−60%)
Phoenix	0.16	21.2 (–)	17.5 (−17%)	13.8 (−35%)	10.1 (−52%)	7.1 (−66%)	4.9 (−77%)
	0.24	23.1 (–)	19.0 (−18%)	14.9 (−36%)	10.9 (−53%)	7.4 (−68%)	5.0 (−78%)
	0.32	25.1 (–)	20.6 (−18%)	16.1 (−36%)	11.6 (−54%)	7.7 (−69%)	5.0 (−80%)
Seattle	0.16	12.2 (–)	11.4 (−6%)	10.6 (−13%)	9.8 (−19%)	9.1 (−25%)	8.3 (−32%)
	0.24	12.6 (–)	11.7 (−7%)	10.9 (−14%)	10.0 (−20%)	9.2 (−27%)	8.3 (−34%)
	0.32	13.1 (–)	12.1 (−7%)	11.2 (−15%)	10.2 (−22%)	9.3 (−29%)	8.3 (−36%)

Table 10
Electric rate increase required to recover utility revenue loss at various solar PV penetration rates with optimal solar PV capacity for the ratepayer (reference case shown for 0.24 $/kW h summer on-peak price).

Location	Homes with PV (%)	Rate increase (%)	Rate price [$/kW h] required to recoup revenue loss		
			Non-summer	Summer off-peak	Summer on-peak
Chicago	0	–	0.120	0.160	0.240
	20	16	0.139	0.186	0.278
	40	38	0.166	0.221	0.331
	60	72	0.206	0.275	0.413
	80	120	0.264	0.352	0.528
	100	192	0.350	0.497	0.701
Phoenix	0	–	0.120	0.160	0.240
	20	24	0.149	0.198	0.298
	40	63	0.196	0.261	0.391
	60	135	0.282	0.376	0.564
	80	268	0.442	0.589	0.883
	100	466	0.680	0.906	1.358
Seattle	0	–	0.120	0.160	0.240
	20	8	0.130	0.173	0.259
	40	19	0.143	0.190	0.286
	60	32	0.158	0.211	0.317
	80	47	0.176	0.235	0.353
	100	66	0.199	0.266	0.398

Table 11
Increase to fixed monthly connection fee to recover utility revenue loss at 20% solar PV penetration for homes with optimal solar PV capacity for the ratepayer.

Location	On-peak price [$/kW h]	Applied to all customers			Applied to only solar customers		
		Additional fee [$/mo]	Total fee [$/mo]	Relative change [%]	Additional fee [$/mo]	Total fee [$/mo]	Relative change [%]
Chicago	0.16	12.50	27.50	83	62.50	77.50	417
	0.24	14.17	29.17	94	70.83	85.83	472
	0.32	15.83	30.83	106	79.17	94.17	528
Phoenix	0.16	30.83	45.83	206	154.17	169.17	1028
	0.24	34.17	49.17	228	170.83	185.83	1139
	0.32	37.50	52.50	250	187.50	202.50	1250
Seattle	0.16	6.67	21.67	44	33.33	48.33	222
	0.24	7.50	22.50	50	37.50	52.50	250
	0.32	8.33	23.33	56	41.67	56.67	278

other controllable assets. Generation units may need to operate at partial load to meet operating capacity and reserve requirements during periods of high solar insolation and thereby produce power at lower efficiency and higher emissions factors.
- Demand response capabilities may serve a greater role in the residential energy market as system-wide operating reserve capacity requirements increase with increases in renewables penetration. Demand response also offers a mechanism to reduce peak power draw at lower cost than on-site battery storage.

Reaching a zero-carbon economy is a challenge that will require technology innovation, new policy approaches, alternative value propositions and rate agreements, new energy business models, and changes in consumer behavior. This study is one of many studies needed to explore that complex decision space, yet it is clear that a business-as-usual approach to distributed solar PV will yield an untenable future for the utility on both technical and financial metrics. Unit commitment and power flow studies could extend this study using a generic generation fleet. Further opportunities for investigation include an analysis of utility-side emissions and economics from running nonrenewable generation at lower loads, evaluating the techno-economic performance of electric vehicles, developing load management scenarios to smooth residential load profiles, and evaluating the consumer-side and utility-side effects of alternative rate structures including tiered rate structures or shorter-duration net metering timeframes (e.g., daily or hourly). Those explorations will take additional computational functionality outside of that currently provided by HOMER or BEopt. Results and findings from this study can be reproduced in HOMER and BEopt using default values and updating the values of variables listed in Sections 3.1 and 3.2 away from default settings.

The provided methods can be applied to other locations using simulated or measured data. Model parameters in BEopt and HOMER can be updated to reflect various building designs, local environmental forcings, rate structures, and equipment costs to recreate and apply a simulated study of other locations around the world. Measured load and solar PV data can also be obtained for a single home or consumer segment to complete a site-specific study of a real scenario. Such case studies are needed to better understand and guide the changing shape of the United States residential energy market.

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