Research Article

Cost implications of increased solar penetration and time-of-use rate interactions

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Abstract

Electricity-grid operators are facing new challenges in matching load and generation due to increased solar generation and peak-load growth. This paper demonstrates that time-of-use (TOU) rates are an effective method to address these challenges. TOU rates use price differences to incentivize conserving electricity during peak hours and encouraging use during off-peak hours. This strategy is being used across the USA, including in Arizona, California and Hawaii. This analysis used the production-cost model PLEXOS with an hourly resolution to explore how production costs, locational marginal prices and dispatch stacks (type of generation used to meet load) change due to changes in load shapes prompted by TOU rates and with additional solar generation. The modelling focused on implementing TOU rates at three different adoption (response) levels with and without additional solar generation in the Arizona balancing areas within a PLEXOS model. In most cases analysed, implementing TOU rates in Arizona reduced reserve shortages in the Western Interconnect and, in some cases, very substantially. This result is representative of the interactions that happen interconnection-wide, demonstrating the advantage of modelling the entire interconnection. Production costs were decreased by the additional solar generation and the load change from TOU rates, and high response levels reduced the production costs the most for high-solar-generation cases. Load change from TOU rates decreased locational marginal prices for a typical summer day but had inconsistent results on a high-load day. Additional solar generation decreased the usage of combustion turbines, combined cycles and coal-fired generation.
Graphical Abstract

Keywords: energy system and policy; production-cost model; PLEXOS; time-of-use rates; solar energy; locational marginal price

Introduction

Electricity-grid operators are facing new challenges in matching load and generation due to increased solar energy generation and peak-load growth. Time-of-use (TOU) rates are one way to address or ease these challenges. TOU rates use price differences to incentivize conserving electricity during peak hours—usually late afternoon and early evening—and encouraging use during low-load or high-generation hours. This strategy is being used across the USA more and more, including in Arizona, California and Hawaii. This study investigates the interactions between TOU rates and additional solar generation on the power system in Arizona.

Utility-scale solar photovoltaic (PV) electricity generation has increased in the USA from 371 MW in 2010 to 31 048 MW in 2017, with the largest installed capacities in California, with 8876 MW [1]. Rooftop solar generation has also increased from 671 MW in 2010 to 10 576 MW in 2017 countrywide. The increasing solar penetration creates the ‘duck-curve’ phenomenon, in which the net load is very low during high-solar-production hours and then the load ramps up very quickly as solar generation decreases in the early-evening hours. Net load is the electricity demand of a system with the variable renewable-energy generation subtracted out—meaning it is the load that the dispatchable generation must meet in order to keep the system demand and generation matched. Historically, utilities and system operators alter generation to meet predicted load and use automatic generation control to match small changes in load and reserves to match larger unexpected changes in the load. Wind and solar generation add a new variable to the problem of matching generation and load, since the availability and generation level of these resources are determined by weather conditions. Traditionally, base-load generation, namely nuclear, coal and some natural gas, meets a large portion of load but lacks the flexibility to change as the load changes. Natural-gas combustion turbines (CTs) are generally used as peakers, meaning that the production can be adjusted quickly to meet the changing load, including system peaks. Large amounts of renewables, especially solar, can create the conditions for overgeneration because the thermal generators must stay on in order to meet the peak load in the late afternoon or early evening but, during peak solar hours (10am–2pm), loads tend to be low and there is more generation than needed. One tool system that operators have to address in overgeneration is curtailment, cutting off the production of a renewable resource to keep the generation and demand balance.

Fig. 1 [2] shows the load and net load for 21 April 2019 and 24 July 2019 in the California Independent System Operator (CAISO) with load as a solid red line and the net load (load less wind and solar generation) as a dashed blue line. On 21 April 2019, there was a particularly low-load and high-solar day, whereas 24 July was a high-load day. For 21 April, the figure shows that the net load has a lower minimum load than the total load by 11 300 MW as well as a higher ramp (the increase or decrease in load over a set period of time), with the afternoon ramp being 7400 MW for the original load and nearly twice that (14 150 MW) for the net load over nearly the same period of 6 h. This resulted in a ramp of 1200 MW/h for the load and 2392 MW/h for the net load. These trends—lower minimum generation and steeper ramps—are increased as more and more solar energy is added to the balancing area or ISO. In contrast to 21 April, when the minimum and maximum loads happened at nearly the same time for the load and net load, for 24 July, the minimum load happened later in the morning while the maximum load happened later in the evening for the net load compared to the total load. Another difference is that the total ramp of 24 July is 1700 MW less for the net load than for the total load, namely 16 800 MW compared to 18 500 MW, respectively, due to the amount of wind on the system.

Fig. 2 [2] shows the generation stacks for the same days as shown in Fig. 1 and includes imports and solar curtailment. For 21 April, during the high-solar hours, the system has a limit to how much solar generation it can use—with the rest exported (shown on the graph as
negative imports) or curtailed (shown in pink); 24 July does not have any solar curtailment or exports. Both days see an increase in imports and thermal generation during the non-solar hours, although that increase is more distinct on 21 April. These two days show a clear interaction between the solar generation, load and thermal generation. Curtailment has increased overall in CAISO, which curtailed 223 GWh of energy in May of 2019—three times as much as the year before [2].

Lower minimum loads and steeper ramps create a more distinct and narrower peak—which is generally more difficult to meet due to limits on flexibility from traditional thermal generation. CTs are used more to meet the peak instead of combined-cycle plants [3], even though CTs are less efficient and thus more expensive. Since they need to run for less time, the incentives change.

The match between variable resource generation and peak load is very important for integrating large amounts of
variable generation [4–6]. Variable generation sources, generally wind and solar, are dependent on weather and geography, and operators have only limited control over them. Generally, they can be curtailed if there is too much, but they cannot be ramped up if load increases, unless the generation was previously being curtailed. Wind and solar energy have seasonal and diurnal patterns that may or may not align with the peak load. The peak load is driven by different factors, depending on weather, climate and local industries.

This analysis focuses on the state of Arizona—where the peak load is not especially well aligned with the solar resource. The average predicted load in Arizona for each season is shown in Fig. 3. This load is from the Western Electricity Coordinating Council (WECC)’s Transmission Expansion Planning Policy Committee (TEPPC)’s 2024 database [7]. Peak load occurs in the summer afternoons roughly between 3 and 8pm. Load in Arizona is driven mainly by air-conditioning loads, which results in summer peak loads being >5000 MW greater than those in other seasons. The peak loads do not match well with peak solar production. Seasonally, spring has the highest solar generation due to the sky being clear, more often compared to summer. Diurnally, the peak production for solar generation is from about 10am to 2pm, while the load peaks later in the day.

Since solar PV generation cannot produce electricity outside of daylight hours, many strategies are being explored to meet the peak demand while integrating solar energy—ideally in a cost-effective way. It is not cost-effective to build solar generators and then build the same capacity in natural-gas power plants to meet peak loads after the Sun has gone down. There is increasing interest in a wide variety of possible strategies to address this problem, including batteries [8], pumped storage hydros [9, 10] and load shifting [6]. Load shifting can take many forms, including demand response, demand management and rate design. In Arizona and several other places throughout the world, including California, Oklahoma, Hawaii and Italy [11–14], TOU rates are being implemented to incentivize customers to reduce their electricity use during time periods that generally have higher demand. Fig. 4 shows the cost per kWh at different times of the day for TOU-rate programmes that are in high-solar-generation balancing areas. It is clear from the pattern of the prices that the utilities are incentivizing customers to use more electricity during high-solar-generation hours in the middle of the day and less after the Sun has set.

The premise behind TOU rates is that charging the same amount for electricity use around the clock is economically inefficient because, when demand is high, electricity is more expensive to produce. TOU rates give customers (electricity end users) an incentive to conserve when prices are higher and an incentive to use more electricity when prices are lower [15]. This results in generally the same annual electricity use, but a lower peak usage and a flatter overall load pattern. This pattern was found by the Brattle Group in a study for Xcel energy in Colorado [16]. The Brattle Group used the Arcturus 2.0 model, which showed that a 2:1 ratio of on-peak:off-peak prices resulted in a 6–10% decrease in peak demand [17]. With a 4:1 ratio of on-peak:off-peak prices, there was a 10–15% decrease in peak demand. Additional technology, such as smart thermostats and programmable hot-water heaters, helped to support the higher range of decrease in peak demand.

TOU rates are not new—Arizona Public Service Company (APS) started using them in the 1970s for some customers as a response to growing air-conditioning loads [18] and has recently expanded them to the majority of

Fig. 3: Predicted average Arizona electricity demand by season for the year 2024
customers. Small customers with an average monthly usage of ≤600 kWh can opt out of the TOU rates [19], although this is rare because APS’s average customer uses >600 kWh. A 2018 study found that, when there are opt-out programmes, ≤96% of customers participate, which is in contrast to an opt-in programme, which can have participation rates as low as 0% [20]. While the Brattle Group study found an upward bound of ~16% load shifting from peak load due to TOU rates, a study in Japan testing critical peak pricing (CPP), using very high rates or even rebate programmes for the 10 highest-load days of the year, found that a 20% decrease in peak demand was the upper limit for most residential customers [21]. Beyond that, the increasing price differential did not have any additional effect. This indicates that customers have reduced all the electricity that they are willing or able to reduce. A 2017 study [15] found a shorter time window for a TOU peak period, such as 3–6pm, was more effective in reducing peak demand than a longer window, such as 7am–7pm.

Javadi et al. [22] used a capacity-expansion model to predict how TOU policies would change the amount of renewable-energy capacity added to the system for a 10-year planning horizon. They found that adding TOU rates into the model resulted in a reduction of the solar capacity added. In contrast to capacity expansion, a previous study [23] used a production-cost model (PCM) to compare TOU rates and CPP rates in regard to their impact on production cost, locational marginal prices (LMPs) and dispatch stacks. It found that the TOU rates were more beneficial compared to the CPP rates and that a 3–7pm peak period resulted in a greater reduction in production cost and LMPs in Arizona compared to a 4–8pm peak period, although not on the highest-peak days.

Utilities have control over how the time frame is set up for the TOU rates; how the ratio of on-peak:off-peak pricing is set; some control over incentives, such as smart thermostat or programmable hot-water-heater rebates; and how they educate their customers. Nevertheless, load changes due to the TOU rates are dependent on the aggregate customer-behaviour changes, which are inherently difficult to predict [24]. Utilities are also subject to the decisions that regulators and customers make regarding the deployment of rooftop solar-generation equipment, which, unlike utility-scale solar generation, is not typically controlled by the utility. Many utilities are petitioning their public-utility commission (PUC) to change the laws around net metering because they say that net metering shifts costs from those with rooftop solar installations to those without. In Arizona, the PUC determined that it was legal to treat customers with rooftop solar installations as a separate class of customers for ratemaking [25]. Most new utility-scale solar projects are single-axis tracking, meaning that they follow the Sun from east to west throughout the day and utilities have the ability to curtail them when necessary, neither of which is true for rooftop solar installations. Single-axis tracking allows the solar array to capture more of the late-afternoon and early-evening solar energy, when energy is most valuable to the power system in the south-western USA.

There has been relatively little research on the impact of load change from TOU rates on system-wide production costs and LMP—the prices for energy that also reflect transmission congestion and losses. This paper focuses specifically on the interaction between additional solar generation and TOU rates. While additional solar generation suppresses the prices during the daylight hours, it is expected to cause increased price spikes in the late afternoon and evening as the Sun goes down. This may increase the cost-effectiveness of a 4–8pm TOU peak period. This study specifically considers the production costs
across the summer and summer-adjacent months (May–September), the LMPs and the dispatch stacks for an example peak day (22 July), an example non-peak summer day (10 July) and an example non-summer day (22 May). The questions addressed are:

(i) Does the optimal time period for load change caused by TOU rates change with additional solar generation?
(ii) Can TOU rates make it easier to integrate additional solar generation by reducing the ramp required of thermal generators?
(iii) How does the dispatch stack change when TOU rates are implemented in combination with increased solar penetration?

1 Methods

A number of factors influenced the selection of study scenarios and decisions surrounding the model. This study utilized the PCM PLEXOS and created combinations of generation scenarios and load scenarios to better understand how the two interact. PLEXOS has been used to study large system dynamics with increased levels of renewable energy [26–28] as well as drought [29] and storage in times of drought [8]. This study uses the WECC 2024 TEPPC database of generators, load and transmission lines [30]. Changes were made to the original database to account for changes that have been announced or changes that are expected since the database was developed in 2014. Load adjustments and increased rooftop solar generation were limited to the Arizona balancing areas in order to focus the study. However, since the Arizona balancing areas interact in significant ways with balancing areas across the WECC, it was necessary to run the PCM considering the entire WECC.

1.1 Production-cost modelling

Energy Exemplar’s PLEXOS is a commercially available PCM that runs a least-cost optimization using mixed-integer linear programming and respecting the constraints in the model. The constraints for generators include maximum capacity, minimum generation, heat rate, ramp rate and fuel source. Costs are inputs to the model as well and can be driving factors given the least-cost optimization. Costs include fuel cost, which varies by region; generator start-up costs; operations and maintenance (O&M) costs; and penalty costs. The transmission infrastructure is also a key input into PLEXOS and is solved using a DC-power-flow model while respecting line-flow limits and taking into account resistance and reactance. The results of the DC-power flow are then taken into account in the system optimization as constraints.

PLEXOS uses a mixed-integer linear optimization to solve the least-cost set of generation resources for every interval of time while taking into account load, transmission constraints and generator constraints, including which generators were on in the previous time period. For this study, the interval was set to hourly and the time horizon was from 1 May to 30 September (153 days, or 3672 h). The choice to run the model from May to September was made to conserve modelling time and because these are the most challenging and expensive months of the year for utilities in the south-west USA. For example, to run PLEXOS and solve the PCM for the WECC TEPPC model required ~40 h of run time for the whole year (Dell Precision T3610) but this time is reduced to ~24 h for the 5 months of interest. The results for the months modelled are reasonable when compared to similar full-year runs [31]. Another choice that was made to manage the PLEXOS run time was to model the focus area, Arizona, nodally and the rest of the WECC zonally. This means that, for Arizona, all transmission lines (>69 kW) were included in the modelling, leading to high geographic resolution, while, for the WECC areas outside of Arizona, the transmission lines were aggregated by zone and the limitations of the transmission constraints between zones were enforced. Table 1 shows the number of generators, nodes and lines modelled for this study.

Fig. 5 shows the balancing areas included in the WECC 2024 TEPPC database [7]. The balancing areas in Arizona, APS, Salt River Project (SRP) and Tucson Electric Power (TEP) (in Fig. 5, APS is labelled as AZPS and TEP is labelled as TEPC) were modelled with high geographic resolution nodally while the rest of the WECC has lower geographic resolution, due to the aggregation of transmission constraints. Since the database was originally developed in 2014, plans and predictions for the state of Arizona have changed. These changes included retiring Navajo Generating Station, which has a capacity of 2250 MW and was shut down in November 2019 [32, 33]. Another important change is the predicted price of natural gas. In the TEPPC model, the gas price varied from $4 per million British Thermal Units (mmBTU) to $6.5/mmBTU, depending on month and region. Since the price of natural gas is predicted to stay between $3 and $4/mmBTU for the next 10 years [34], the price of natural gas in this model was set to $4/mmBTU across the model. Due to the changes in water availability, this study used a moderate-drought scenario for the Colorado River basin [31] developed in conjunction with the United States Bureau of Reclamation to better represent hydro in the south-west. Compared to the hydro in the original TEPPC model, the moderate-drought scenario reduced hydro availability in the summer, which leads to a slight increase in production costs and LMPs. This analysis focused on Arizona and so the balancing areas presented in the results and load include APS, SRP and TEP.

Table 1: Outlines the number of specific elements in the TEPPC model.

| Element     | Number in TEPPC model |
|-------------|------------------------|
| Generators  | 4626                   |
| Nodes       | 72                     |
| Lines       | 1103                   |
PCMs do not include capital costs—the costs associated with building a new generation resource. For the purposes of this study, capital costs are considered outside of the scope. Thus, comparing across the generation profiles in this study is only valid for the operational costs, including fuel cost, start costs and variable O&M costs. This does provide a large amount of information about the system impacts of different generation-profile decisions.

1.2 Load change
The TEPPC database includes predicted load for 2024, which is based on 2005 actual values and has been validated by balancing authorities. This TEPPC load was used as the business-as-usual (BAU) load and also the starting point for the TOU-rate changes. The BAU-load for Arizona for each day in July is shown in Fig. 6, where the thin coloured lines show the load for each individual day and the thick black line shows the average-load day for July. With a peak of 21 170 MW at 5pm and a total electricity usage of 392 044 MWh for the day, 22 July is representative of a ‘peak-load’ day. In contrast, 10 July, which is the closest to the average July load, has a peak load of 19 288 MW at 5pm and a total demand of 328 545 MWh. For analysing the load changes and the LMPs in the results, 22 July and 10 July are used as representative days.

The TOU changes in load used in this study build on the load changes from Bain [23]. There are two time periods, namely 3–7pm and 4–8pm, and three response levels of Low, Mid and High. This resulted in six load profiles in addition to the BAU-load case. A ‘Low’ response level by customers to the TOU rate had a 6.9% decrease in peak demand, while a ‘Mid’ response level had a 10% decrease.
and a ‘High’ response level had a 15.8% decrease. The energy use for the day, however, does not change; it is shifted to other hours of the day. There is no published academic work focusing on how implementing a TOU rate alters the load distribution of displaced energy from the peak period. However, discussions with utility insiders indicate that a clustered distribution is most likely, since households often pre-cool their houses in the summer and turn on appliances after the TOU period is finished. The previous study [23] found very little benefit to an even distribution and thus this study focuses only on the cluster distribution, meaning the hours closest to the peak period having more displaced energy added to them (8%) compared to the hours furthest away from the peak period (4%). The energy use displaced from the peak period is redistributed to the other hours of the day, as shown in Fig. 7.

The shapes of the six different load-change scenarios can be seen in Fig. 8. The thin black line shows the BAU-load, while the red solid line shows the load for the 3–7pm TOU period and the dashed blue line shows the load for the 4–8pm TOU period. As is evident in all three of the plots in this figure, the TOU rate causes the peak loads to occur during the hour before the ‘on-peak’ billing period starts. For the 3–7pm TOU period, this is 2pm and, for the 4–8pm TOU period, this is 3pm. For the 4–8pm TOU period, the 3pm peak is higher than the original BAU-load peak. Thus, the TOU rates shift the peak to hours when solar PV generation is being used. For all the 3–7pm cases, the new peak is less than the BAU-load peak of 21 270 MW. The amount of displaced energy from the TOU period increases with the increasing levels and, as a result, the demand in the hours adjacent to the TOU period increases proportionally. This means that the Low response decreases the peak by the smallest amount and increases the load in the adjacent hours by a small amount, while these changes are higher in the Mid response and highest
in the High response. As will be presented in the ‘Results and discussion’ section, though it would be reasonable to assume that the production cost, LMPs and dispatch will change the most due to the High response level, that is not always the case.

### 1.3 Generation-profile changes

In addition to changing the load, three solar scenarios were created: additional rooftop solar installations, additional utility-scale solar installations and additional rooftop and utility-scale solar installations. The utility-scale solar additions totalled 700 MW with locations throughout the state of Arizona, with 250 MW in Page, 250 MW in Cameron, 100 MW in Phoenix and 100 MW in Tucson. The System Advisor Model (SAM) [35] was utilized to create the hourly solar-generation profiles for each of the locations. Table 2 indicates the location and capacity for the additional utility-scale solar installations.

The rooftop solar scenario was created by increasing the multiplier for the rooftop solar installation already inside the model for the balancing areas in Arizona (APS, SRP and TEP) resulting in a 4-fold increase in the rooftop solar generation for Arizona compared to the original amount in the 2024 WECC TEPPC database. This increase is in line with the forecast for rooftop solar generation included in APS’s 2017 Integrated Resource Plan [36].

Fig. 9 shows the rooftop and utility-scale solar generation throughout the day for 22 May (a low-load day) and 22 July (a high-load day) for the BAU-generation (BAU-gen) and the increased-generation scenarios. The BAU-gen is shown with the solid lines and the increased generation is shown with the dashed lines. The utility-scale PV generation in Arizona is blue while the rooftop solar generation is red. The utility-scale solar generation has a flatter curve and generates longer into the evening due to the single-axis tracking following the Sun during daylight hours. It also has less capacity and generation over the day than the rooftop solar generation. The rooftop solar generation has a narrower shape, with the highest generation from 10am to 3pm. There is more generation on 22 May compared to that on 22 July, which is typical for Arizona, as the spring has more clear-sky days than in summer for the region.

Table 3 shows the relative amount of solar generation from utility-scale and rooftop solar installations in each of the four generation scenarios. For the BAU-gen scenario, both types of solar generation are at the BAU-gen level, which includes the solar generation in the TEPPC 2024 base model, while, for the ‘utility-and-rooftop solar’-installation scenario, both types are at the increased level. For the ‘utility solar’-generation scenario, only the utility-scale solar generation was increased, while for the ‘rooftop solar’-generation scenario, only the rooftop solar generation was increased.

Fig. 10 shows the net load for each of the generation cases with the BAU-gen load for a low-load and a high-load day (22 May and 22 July). The red line shows the load with no solar generation subtracted. In contrast, the magenta
line shows the net load for the utility-and-rooftop case, which has the increased rooftop solar generation and increased utility-scale solar generation subtracted from the load. For the low-load day, the ‘duck-curve’ shape starts to present itself, especially for the rooftop and utility-and-rooftop-generation profiles. For the utility-and-rooftop
case, a minimum net load of 6874 MW occurs at 9am and the peak occurs at 6pm with a load of 13 147 MW. In comparison with the BAU-gen case, the ramp-up between the lowest and highest net-load points for the utility-and-rooftop cases results in a larger change in power over a shorter time period; i.e. it has a steeper ramp. On 22 May in the BAU-gen case, the low load occurs at 4am. In comparison, the minimum net load in the utility-and-rooftop scenario decreases relative to BAU-gen and it occurs 5 h later at 9am. In the right panel of the figure, on 22 July, the peak load of 21 210 MW happens at 5pm. With the BAU-gen, the peak net load is still at 5pm, but has decreased to 20 874 MW. For all the generation profiles with additional solar generation beyond the BAU-gen, the peak moves to 6pm and is ~20 750 MW. Since the load is so much higher in July than in May, the amount of additional solar generation in this study does not induce the ‘duck-curve’ shape and its associated challenges.

Fig. 11 shows the net load for 22 May for the TOU Mid case for both the 3–7pm and the 4–8pm TOU-rate scenarios. Though different in magnitude, these plots are representative of all the cases studied. In the figure, note the location of the utility-and-rooftop-generation case represented by the magenta line; it is the line farthest to the left on each graph. The minimum load for this case is higher by almost 200 MW than for the same generation case shown in Fig. 10 due to the TOU load being redistributed from the on-peak-rate time period. The peak for all the TOU 3–7pm cases is 13 288 MW at 8pm and is 13 144WM at 9pm for all of the 4–8pm cases. These are less than the BAU-gen scenario peak load, which is 13 371 MW at 5pm, and also less than the rooftop-generation scenario peak load, which is 13 362 MW at 6pm. Since the utility-scale solar generation produces later into the day than the rooftop solar generation, it has more of an impact on reducing the peak of the load. This can be seen with the green line for the utility-scale scenario and the magenta line for the utility-and-rooftop scenario.

Fig. 12 shows the TOU Mid-case net load for 22 July (a high-load day) for both TOU time periods. The colours for each of the generation scenarios are the same as in Fig. 10. Without the additional solar generation, the peak load occurs in the hour preceding the TOU window. For the 3–7pm TOU period, the 2pm (hour 14 in the plot) net-load peak is lower than the 8pm peak for all scenarios, including the BAU-gen case. For the 4–8pm TOU period, it is only when the additional rooftop solar generation is included that the 3pm net peak load is lower than the 9pm peak. There are two reasons for this: the solar generation has a larger impact at 2pm than at 3pm and the peak after the end of the TOU period is higher when the period ends at 7pm than when it ends at 8pm. The solar generation in the state of Arizona does not impact the peak after the TOU period ends because the Sun has gone down by that time.

2 Results and discussion
In order to answer the research questions posed earlier, the results are focused on understanding the impacts of TOU rates combined with increased solar PV generation on system operation and dispatch, and how the combination of these changes the costs. The results are presented in four sections: ‘Validation of model and baseline performance’, ‘Arizona production costs’, ‘LMPs’ and ‘Generation dispatch stacks’. The goal of the first section is to show

![Fig. 11: TOU Mid 3–7pm and 4–8pm net loads for an example low-load day (22 May)](https://academic.oup.com/ce/advance-article/doi/10.1093/ce/zkaa010/5881812)
how each of the metrics presented responded in rational ways to the generation and load-shape changes, thus supporting the conclusions in the subsequent sections. The production cost is presented for Arizona balancing areas and shows the cost to produce the electricity for the May–September period. Comparing the production costs across scenarios gives insight into how the changes made to the generation profile and the load-shape change the cost of producing electricity in the state. The LMPs show the price of electricity at a specific location at a specific time. This gives a more granular view than the production costs and focuses on a few of days of interest, a high-load day (22 July), a typical summer day (10 July) and a low-load day (22 May). The ‘Generation dispatch stacks’ section shows the change in dispatch by hour for generation types, thus giving an even more detailed view than the LMPs give. Dispatch stacks give insight into what types of generation were used or not used in response to the changing generation and load shape.

2.2 Validation of model and baseline performance

Prior to comparing production costs, LMPs and dispatch stacks, it is necessary to establish that the model is working as expected and producing results representative of realistic electrical-system operation. An important check of the validity of a PCM is the amount of ‘unserved energy’. An electrical system, such as the WECC, should have sufficient generation and reserves to meet the expected load. If some of the load is not met, PLEXOS records it as unserved energy and it is an indication of a potential problem in system operation. None of the PLEXOS simulations included in this study had unserved energy.

2.2.1 Reserve margin

Similarly, if the amount of reserves shortages were >5 GWh, which is ~0.02% of reserves provided (25 798 GWh), this indicates that more generation needs to be available for providing reserves. The reserve shortages for the 5-month May–September period for all of the WECC are shown in Fig. 13. In Fig. 13, the BAU-load cases are shown with red bars, the 3–7pm TOU-period cases are green and the 4–8pm cases are blue. The vertical axis shows the amount of reserve shortages in GWh while the horizontal axis shows the level of penetration of the TOU rate on the load (Low, Mid or High). The dashed line is for the BAU case with no additional solar generation or TOU-load changes (BAU-load/BAU-gen) and shows a reserve shortage of 1.316 GWh. The reserve shortages for the cases with additional solar and TOU-load changes were found to have a range of 0.036–2.21 GWh, which is in line with shortages found in a previous study [31], and they are still a small percentage of the total reserves provided. Since the majority of cases have reserve shortages below the dashed line, they indicate a reliability improvement as a result of the additional solar generation and the TOU-load changes. The addition of rooftop solar generation is a notable exception (see the two bars on the right side of the middle bar chart for ‘rooftop solar’), because rooftop solar generation contributes very little to the highest-load hours at 5pm and 6pm. Also, for the additional rooftop-solar cases, there is a clear
reliability improvement with the 4–8pm compared to the 3–7pm TOU-load change resulting from the lack of generation during the highest-load hours. For the cases with the utility-scale solar generation, due to the utility solar generation extending further into the evening (see Fig. 9), the 3–7pm TOU-load change tends to yield lower reserve shortages.

In Fig. 13, the most significant reduction in reserve shortages compared to the BAU-load/BAU-gen is seen for the utility-and-rooftop TOU High 4–8pm case (97% reduction) and exemplifies the interconnectedness of the whole system and the benefit of modelling the entire interconnect. Reducing WECC-wide reserve shortages not only increases the reliability of the system but, since there are fees associated with reserve shortages, also decreases those fees.

2.2.2 CT starts

CT starts were also included in the validation of the model and were compared to Arizona CT starts found in similar studies [8, 37]. These studies, which focused on adding battery storage to Arizona and California, found fossil-fuel plant starts to be between 2000 and 4000 in Arizona for the whole year, with the largest proportion of starts being CTs. Since this study focused on only May–September, it is expected for start cycles to be about half of those seen in the Wadsack studies [8, 37], which is exactly what was found with CT starts between ~1050 and 1650 in this study.

Fig. 14 shows the number of CT starts, with each panel showing a different generation profile and with the dashed line indicating the number of CT starts for the BAU-load/BAU-gen, which was 1297. The BAU-load with additional solar generation for each generation profile had the highest number of CT starts (see the red bar in each chart, which represents the BAU-load). As the TOU rates are applied, the number of CT starts decreases. The reduction in peak load due to the TOU-load shift reduces the number of CT starts in two ways. First, the load peak is lower and that reduces the overall capacity needed to meet peak load, which is met with CTs when needed for a short period of time. Second, the displaced energy from the TOU period shifts the energy used to off-peak times, which in turn increases the baseload needs. More base-load displaces some CT starts. There is not a clear benefit for one particular response level or time period versus any other. This indicates that the important change is the implementation of TOU rates, not the specific details about the set-up.

2.2.3 Net imports

Examining the net imports is a check that the interconnections within the model are continuing to work as expected when additional generation and load changes have been in one area of the model. For net imports, the focus is on one balancing area in order to eliminate possible double counting with the balancing areas in Arizona importing and exporting to each other. Fig. 15 shows the net imports to APS compared across cases. In the BAU-load/BAU-gen case, while utility solar generation is in green, rooftop solar generation is in teal and utility-and-rooftop generation is in purple. Since the additional generation was the largest driver of a decrease in the net imports, the labels for the individual cases were removed. Lower net imports
when there are more generation resources in a BA make sense, since the BA will have more generation to export and need less imported. This result is a confirmation that the PCM is responding rationally to the additional solar generation.

2.3 Arizona production costs

The production cost is calculated as a sum of the total generation cost for all hours of the modelled time period (May–September) for the year 2024 for the selected balancing areas within the state of Arizona, which includes APS, SRP and TEP. For this analysis, the production cost does not include penalties. The production cost will be shown for Arizona only, since this is where the TOU rate and increased solar changes are implemented and where the greatest impact is expected. Each set of solar additions decreases the production cost. This is expected, since the solar generation is added in the PLEXOS model as a resource that does not include a fuel cost, making it a zero marginal cost-generation resource. Fig. 16 shows the total production cost from May to September for the four generation profiles with no TOU-load changes: BAU-gen, additional utility-scale solar, additional rooftop solar and additional utility-and-rooftop solar. The BAU-gen has a production cost of $730 million and it decreases with
additional generation resources, to $719 million for the additional utility-scale solar, $706 million with additional rooftop solar and $699 million with both additions.

The decrease in the production cost for utility-and-rooftop solar generation is not cumulative. The addition of utility solar decreases the production cost by $11 million.

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**Table 4.** Production cost in millions of dollars ($ million) for the cases shown in Fig. 17

| Time  | Level | BAU-gen | Utility solar | Rooftop solar | Utility-and-rooftop |
|-------|-------|---------|---------------|---------------|---------------------|
| 3–7pm | Low   | 725.6   | 716.4         | 701.7         | 694.6               |
| 3–7pm | Mid   | 723.4   | 711.0         | 700.4         | 693.3               |
| 3–7pm | High  | 721.7   | 711.9         | 702.3         | 690.7               |
| 4–8pm | Low   | 721.0   | 715.0         | 704.7         | 697.7               |
| 4–8pm | Mid   | 725.0   | 717.8         | 703.6         | 692.2               |
| 4–8pm | High  | 723.8   | 715.0         | 700.9         | 691.8               |
and the addition of rooftop solar decreases the production cost by $24 million, while the utility-and-rooftop additions decreases the production cost by $31 million. If the decrease was cumulative, it would have been $35 million. Because the additional solar energy generates at the same time, it becomes less valuable as more is added in a balancing area.

Fig. 17 shows the impact of the TOU rates on the production cost for the four generation profiles used in this study. The production cost is on the vertical axis and the response level (Low, Mid, High) is on the horizontal axis, while the panels show the generation profiles. Compared across the panels are the two time periods for the TOU rates, with red showing the 3–7pm time period and green showing the 4–8pm time period. The leftmost panel shows production costs for the BAU-gen case, which are higher than the others due to less solar generation. The patterns for the BAU-gen case and the utility solar case are very similar. For the Low response, the 4–8pm time period has the lower production cost but, for the Mid and High response levels, the 3–7pm has the lower production cost. Overall, the 3–7pm time period results in the lower production cost more often than the 4–8pm time period. In the rooftop and utility-and-rooftop cases, the 3–7pm cases have lower production costs for the Low response levels. If a utility/balancing area operator is similar to those in Arizona, implementing a TOU-rate structure may yield the most benefit if choosing the 3–7pm time period. However, the magnitude of the savings resulting from a TOU rate depends strongly on both the characteristics of the solar generation and the generation/transmission assets at the disposal of the balancing area. Consequently, it is difficult to generalize selection of a time frame for the TOU rate. However, when comparing Fig. 16 and Fig. 17, it is clear that implementing a TOU rate will reduce production costs.

Generally, it is expected that higher response levels will lead to higher production-cost savings. Comparing the production costs versus the response levels in each panel of Fig. 17 for the 3–7pm time period, production costs generally decrease with increasing response to the TOU rate. For the 4–8pm time period, production costs follow this trend when the solar generation is higher. This means that the additional solar generation makes this pattern more likely to occur because a higher TOU response level results in a lower load when the solar generating stops, thus resulting in less CT generation and a lower production cost. At the lower solar penetrations (BAU-gen and utility solar), the production cost does not decrease consistently as the TOU response level increases. This may be because, at lower solar penetration, the ideal TOU response is Low or Mid, as opposed to High.

2.4 LMPs

The LMPs are presented for a low-load day (22 May), a typical summer day (10 July) and a high-load day (22 July) for the state of Arizona and are an average of the LMPs for all nodes in the state by hour. For all three dates, two figures will be shown. The first shows the LMPs with only the generation changes (BAU-gen plus solar cases) presented, while the second includes the changes due to the TOU-load changes.

Fig. 18 shows the LMPs throughout the day for the low-load day for the four generation cases with no TOU-load changes. There is a distinct dip in LMPs during the morning hours of 9am, 10am and 11am attributable to the additional solar generation, with a minimum LMP of $16.84/MWh. The two cases with largest amount of additional solar generation show the largest decrease in LMPs during the day. The load is relatively low compared to a July day and so the solar energy is displacing other generation

![Fig. 18: LMPs for 22 May for the BAU-load and the four generation scenarios](https://example.com/fig18.png)
forms and therefore drives the prices lower. The evening pattern exhibits a double peak at 6pm and 9pm, each ~$32/MWh even without TOU rates applied. The first peak at 6pm corresponds to a drop-off of solar generation, particularly from utility-scale solar generation.

Fig. 19 shows the LMPs for the generation scenarios with the TOU rates. The thin black line shows the BAU-load LMPs for each generation scenario, while the red line shows the 3–7pm cases and the teal line shows the 4–8pm cases. The top row of the figure shows the Low response level and each column shows a different generation profile, starting with the BAU-gen profile on the left, then the utility-scale, then rooftop, then utility-and-rooftop on the right. The BAU-load cases for the low-load day show a double peak for LMPs, while the TOU cases decrease the first peak at 6pm from ~$32 to ~$27/MWh and increase the second peak at 9pm from ~$32 to ~$35/MWh. Thus, the load changes due to TOU rates impact the prices for electricity in Arizona by reducing them at the 6pm hour but, because the TOU period ends at about the same time as the second peak occurs, the 9pm LMP peak is increased. It takes more expensive electricity generation to meet the load for the 9pm hour. There is a trade-off here for lower prices at 6pm but higher prices at 9pm.

Fig. 20 shows the LMPs for a typical summer day (10 July) for the load profiles investigated. Note that the peak...
LMP for the day increases with additional solar generation, seen at the 5pm, 6pm and 7pm hours. The peak is most pronounced with the additional rooftop solar generation (green line) because the drop-off in generation is more severe and happens earlier than with utility-scale generation. This increases the need for flexible, often expensive, energy to come online when the rooftop generation declines. The availability of solar generation during the day and the goal of minimizing production costs incentivize baseload resources to be offline. When the solar generation stops, baseload resources that could reduce the higher LMPs experienced late in the day are not available. The prices are, however, slightly lower during solar-generation hours (9am–4pm) in the additional solar cases compared to the BAU-gen case. As with the low-load day, the additional solar generation during the day decreases prices, but not as much as on the low-load day, because the typical summer day has more load and thus more capacity to absorb the additional energy.

Fig. 21 shows the LMPs for the four generation scenarios and the three TOU response levels. It is set up in the same way as Fig. 19. For the majority of cases, the TOU scenarios decrease the LMPs, with the one exception being the utility solar Low 3–7pm case, which has an increase in LMPs at 5pm and 6pm. This is an unexpected result, although not unrealistic. LMPs are based on the generation online and available in the balancing area where the node is and also on the generation available to import from surrounding areas. In this case, the online generation units and the generation available to import resulted in higher LMPs than in the BAU-gen case. The other cases respond in an expected way, with LMPs decreasing during the 5pm and 6pm hours.

Fig. 22, similar to Fig. 20, shows the LMPs for the four generation profiles with the BAU-load for the high-load day (22 July). The BAU-gen profile has the longest period of high prices (>100/MWh), at 3 h (5pm, 6pm and 7pm). These prices are much higher than those seen on the low-load and typical summer days because this is a peak-load day and the system is stressed to meet the demand with the available generation. It is also a peak-load day in several of the neighboring states, which thus increases the price of electricity across the region. The additional rooftop solar-generation profile reduces the high prices to 2 h (6pm and 7pm). For the additional utility solar- and utility-and-rooftop-generation profiles, the high prices only occur during the 6pm hour. (The green utility solar line is directly behind the utility-and-rooftop line, which is purple, in Fig. 22.) The addition of solar generation reduces the number of high-priced hours on the highest-load day of the year. Due to the shape of utility solar, there is a reduction in the high-priced hours from 3 to 1 h, whereas the rooftop alone reduces the high-priced hours from 3 to 2. There are minimal differences in the LMPs between the scenarios outside of the 4–6pm hours. This is due to the high load, which is able to absorb more solar energy without it having an impact on prices.

Fig. 23 shows the LMPs for Arizona for the peak-load day and is set up like Figs 19 and 21. In 7 of the 24 cases, the number of high-priced hours is reduced from 3 h to only 1 h. The reduction in high LMPs in these cases is driven more by the addition of solar generation and less by the inclusion of TOU rates. Fig. 22 shows that the addition of solar generation reduces the peak prices from 3 h in the BAU-gen case to 2 or 1 h, depending on the additional solar generation; however, the load change due to
TOU rates did not consistently reduce the peak LMPs and, in several cases, exacerbated the problem. Focusing on the second row in Fig. 23, which shows the Mid-level response, the application of load changes due to the TOU rates does not impact the LMPs in a consistent way. For some, the high LMPs are reduced, while, for others, the high LMPs occur for more hours than with solar and no TOU rates. This means that, for the highest-load days, the TOU-load changes do not help to reduce LMPs, and in fact can make the price spikes worse due to the additional solar generation. It also suggests that the driver for the high prices is not simply the load in Arizona, but more likely the high load throughout the area and constrained resources.

For the 3 days presented, the TOU window is a mismatch for the low-load day, is well suited for the typical summer day and has inconsistent impacts for the peak-load day. A utility wanting to implement a TOU rate may consider different options, such as using a different time period for non-summer months or, if the utility is most concerned with summer, consistently using the time period that is most beneficial for summer days. In this case, both the 3–7pm and the 4–8pm time periods show similar LMP reductions for the typical summer day.

2.5 Generation dispatch stacks
Fig. 24 shows the change in generation dispatch between the BAU-gen case and the three additional solar cases, and does not include any TOU-load changes. As displayed in the figure, in all cases, the additional solar generation...
results in decreased use of CTs, combined cycles and some coal-fired generation. The decrease in these types of generation increases as the additional solar generation increases, but the decrease is never as much as the additional generation. This means that the additional generation is also replacing imports or being exported, thus taking advantage of the interconnected system.

**Fig. 24** shows the generation dispatch for the TOU 3–7pm cases compared to the utility-and-rooftop BAU-load case, so the changes shown in the figure are directly attributable to the level of TOU response. The 4–8pm cases were analogous and thus not shown. Similar to **Fig. 24**, the change in load results in less generation from combustion-turbine and combined-cycle plants. In the Low and Mid cases, the majority of decrease in generation is in CT-NatGas compared to the High case, where there is a significant decrease in CC-NatGas generation. This indicates that the ability to decrease CT-NatGas has been exhausted and
When implementing a load change due to a TOU rate, generation increased, its incremental value was reduced. Of the bulk electric system. As the amount of added solar additional resources or changes in load are to operation of the TOU-load changes had minimal impact on imports. Balancing area resulted in decreased imports, while the turbine starts. The addition of solar generation in the APS sources online, resulting in the reduction in combustion-turbine starts compared to the BAU-gen case, and the implementation of TOU rates decreased combustion-turbine starts with TOU rates the most. Of the two time periods tested, the 3–7pm time period resulted in the lower production cost more often than the 4–8pm time period did. Thus, if a balancing system operator with similar net load/generation to Arizona wanted to implement a TOU-rate structure, their production costs would be lower if they chose the 3–7pm time period.

When considering the impact of additional solar generation and TOU-load changes on LMPs, three example days were presented: a non-summer day, a typical summer day and a high-load summer day. For the typical summer day, the additional solar generation caused a slight increase in LMPs in the early-evening hours, while the load change due to TOU rates resulted in reduced LMPs in the early-evening hours for the majority of cases. While the additional solar energy increased the prices of electricity during peak-load hours, the use of TOU rates helped to mitigate that effect on average summer days. For the non-summer day, the additional solar generation, in particular the additional rooftop generation, reduced LMPs during the middle of the day, but did not impact the LMP double peak in the evening at 6pm and 9pm. The load changes due to TOU rates reduced the 6pm LMP but increased the 9pm LMP, suggesting that the TOU time period is not optimal for reducing LMPs on non-summer days. For the high-load day, the addition of solar generation reduced the number of hours for which the price spike occurred, but the load change due to TOU rates had inconsistent results, suggesting that load in Arizona is not the only driver of the high prices. For typical summer days, TOU rates had the desired effect on the LMPs, while the impacts were mixed for non-summer days and minimal for high-load days. A balancing area operator may decide that this is acceptable, since typical summer days make up the majority of days between May and September.

Regarding generator dispatch, when additional solar generation was added, there was decreased usage of CTs, combined cycles and coal-fired generation. The decrease was less than with the additional solar generation, which means that the additional generation replaced imports or was exported. This was another result that points to the importance of the interconnected electricity system.

This study showed that load change as a result of TOU rates is an effective means of addressing peak load and is an effective means of addressing some of the challenges introduced with additional solar generation on the bulk electricity system. There are both reliability benefits and cost savings with the TOU-load changes.

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Conflict of Interest
None declared

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