  

Programs, Pricing, and Politics in a High Solar Future

Prepared by
John Romankiewicz

Goldman School of Public Policy
Energy & Resources Group
University of California – Berkeley

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Executive Summary

"The policy elicits the technology." Robert Socolow – Physicist, Princeton University [1]

In 2014, solar energy produced 5% of California's electricity and, owing to governmental subsidies and mandates, is likely to produce more than 25% by 2025. Because solar is a daytime only resource, there will soon be frequent daytime occurrences of overgeneration – when there is more supply than demand. Additionally, as the sun sets, other resources will need to ramp up quickly to maintain the supply demand balance.

Overall, management of the electricity grid will need to become much more flexible. Strategies for flexibility could be oriented principally towards either supply or demand. Demand-side strategies could be a lot less costly, however. One analysis finds that a high solar RPS where electricity storage was primarily used to supply flexibility would cost ratepayers $1.8 billion more than if demand side resources were used to accommodate the growth in solar.

As more solar comes online, wholesale energy prices will change rapidly, becoming inexpensive during the day and relatively more expensive in the evening. Time-of-use pricing offers an opportunity to pass these prices through to customers on the retail side, so that customers can use relatively more energy during low-priced day periods and relatively less in high-priced evening periods.

Demand-side solutions, however, face more political obstacles than do supply-side solutions: a procurement mandate already exists for storage. This situation is changing, though, as emerging technologies will help consumers track and shift their electricity usage by time-of-day much more easily and accurately. That trend, plus consumer education, should make time-sensitive pricing much more acceptable.

"A shift in relative prices acts like a glacial drift, imperceptible in the short run, irresistible in the long run." Morris Adelman – Economist, MIT [2]

[1] Quoted in (Gertner, 2008)
[2] Quoted in (The Economist, 1981)

The Problem and Potential Solutions

As the RPS increases and solar accounts for much of the new capacity, there is a need for more flexible supply resources. Demand-side resources that reduce the need for flexibility could potentially have lower costs than those supply side resources but may face political barriers.

A renewable portfolio standard (RPS) of 33% is in place for 2020, and legislative proposals for a higher RPS of 50% are currently underway. Given that solar technology has fallen in cost precipitously, much of the incremental RPS will be met with new solar generation.[3] Because solar is a daytime only resource, there is going to be an increased need for flexibility. Namely, there will be 1) overgeneration issues during the day when there is more supply than demand and 2) ramping issues in the evening when resources need to ramp up quickly as the sun sets.

Many existing supply side resources are ill-suited to provide flexibility. As a result, the state's grid system operator – the California Independent System Operator (CAISO) – and the electric utilities are laying the foundation for a market where the grid's supply side resources optimize not only for energy and capacity but also for flexibility. Increasing the supply of flexibility, however, is only one of the two potential solutions.

The other solution – to decrease the demand for flexible capacity – will be the focus of this policy analysis. The primary avenue to reducing the demand for flexible capacity is to use proportionally more energy during the day and proportionally less energy during the evening. The means to achieve this result involve a combination of retail pricing technologies, program adjustments, and enabling technologies which will be detailed in this report.

Decreasing the demand for flexible capacity has the benefit of being a less costly avenue to meet a high RPS, but the danger of being less politically achievable for reasons that will be explained in this report. While a full cost-based calculation of the two options is beyond the scope of this analysis, another widely quoted analysis by consulting firm Energy and Environmental Economics notes that a high solar RPS where electricity storage was primarily used to supply flexibility would cost ratepayers $1.8 billion more than if demand side resources were used to accommodate the growth in solar (EThree, 2014).

This report will have four pieces of analysis: planning, programs, pricing, and politics. The planning analysis will review the approaches to flexibility and their relative costs. The programs analysis will analyze near-term opportunities in energy efficiency and distributed generation that demonstrate the economic feasibility of many demand-side solutions. The pricing analysis will analyze the medium-term opportunity to design retail rates in a way that decreases the need for supply flexibility. The politics section will analyze the relative political feasibility of supply side and demand-side approaches to flexibility, with a focus on time of use pricing.

[3] This is an assumption based on current expectations of solar costs; however, there are avenues to pursue an RPS and overall greenhouse gas reductions with other technologies if those technologies are mandated or fall in cost.

While curtailment and demand response are cost effective measures to provide flexibility in the near-term, a 50% RPS will require a new flexibility solution such as storage, load shifting, or increased trading with neighboring states. While demand-side flexibility measures offer the potential to be a low-cost solution, that potential is not yet fully understood.

The flexibility problem is largely broken down into two requirements: downward flexibility and upward flexibility. Downward flexibility refers to the ability to decrease supply or increase load. Conversely, upward flexibility refers to the ability to decrease load or increase supply. More background on the exact quantitative nature of the flexibility problem can be found in section 1 of the Appendix.

From here, there are three categories of options and many alternatives. The categories (as shown in Figure 1) are supply-side flexibility, demand-side elasticity, and load re-shaping – the latter two of which constitute options that decrease the need for flexible resources. The large majority of the solutions described below can actually be used to address both downward and upward flexibility issues.

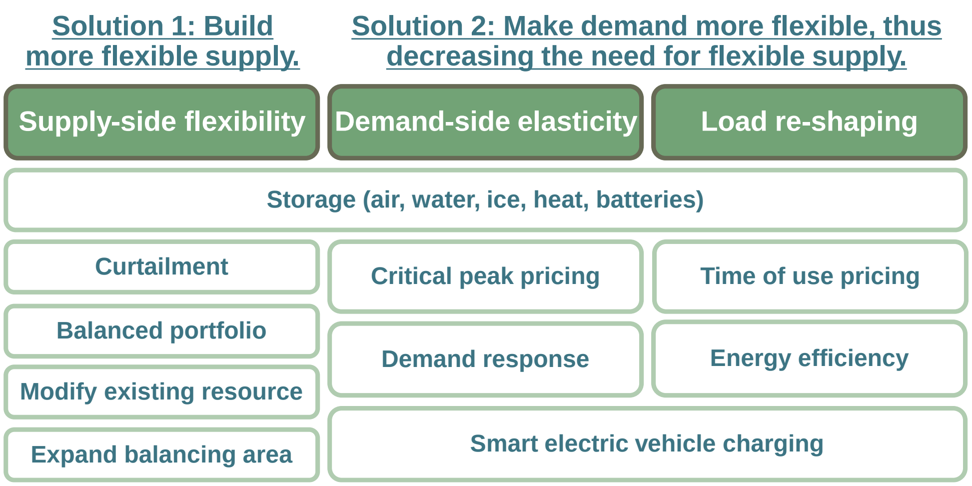

Figure 1: Potential solutions for power system flexibility

The supply-side solutions include curtailment of renewables during overgeneration events, a balanced portfolio (e.g. wind and biomass are built in place of some solar)[4], modifying existing power plants to be more flexible, and expanding the balancing area by building transmission and increasing electricity trade with other states.

On the demand side, solutions include short-run demand-side price elasticity and long-run load re-shaping. Demand can be reduced during critical peaks by increasing the rates or offering

[4] Biomass resources will have fewer flexibility issues, while wind typically still has flexibility issues, but often of a different nature from those of solar.

rewards for reductions in load.[5] Long-run load re-shaping involves using time of use pricing for loads that can be time shifted (for example, water heating and air conditioning) and using energy efficiency for loads that cannot be time shifted (for example, lighting). Smart charging of electric vehicles (EV's) will be an increasingly common solution whereby EV's can be responsive to retail price and grid conditions. Overall, demand elasticity can be exploited in both the short-run and the long-run with well-designed incentives and rates in order to modify demand, though these tools are not perfect and need improvement.

Lastly, energy storage is a solution that can fall along all three categories. Storage on the supply-side exists typically either as pumped hydro storage or large-scale batteries. On the demand-side, many customers are beginning to purchase batteries, though lower cost (and sometimes lower capacity) solutions exist in thermal storage (hot and cold air and water) for loads where the end use is heat (refrigeration, air conditioning, space heating, and water heating). Typically, customers and utilities become interested in storage purely from the perspective of a price arbitrage opportunity. Often, energy is expensive in one period and inexpensive in another, and thus storage can help save money by 'using' more during the inexpensive period and storing it for later use.

Near-term flexibility needs have supply and demand side solutions

Demand response and curtailment can be cost-effective solutions to near-term upward and downward flexibility needs from the perspective of the utility. Demand response has long been used to avoid building additional generation capacity. Typically, total electricity demand is unusually high on a small number of very hot summer days due to air conditioning needs. In the five years from 2009 to 2013, it was estimated that the top 5% of peak load occurred within only 24 hours, or 0.05% of the total hours within that period. Furthermore, 10% of peak load occurred within only 100 hours, or 0.23% of the total hours. The peaky nature of the so-called "load duration curve" can be seen in Figure 2. To build supply capacity for such a short amount of peak load would cost upwards of $120-130 per kilowatt-year, while demand response programs can pay large customers around $55 per kilowatt-year to reduce load thus realizing an enormous savings relative to the cost of building new capacity.[6] The capacity bidding program is one example of such a demand response program run by PG&E and can be called when CAISO predicts a gross load above 43,000 megawatts.[7]

On the right side of the load duration curve, there are a small number of hours with a very small net load. A small net load leads to a risk of overgeneration where there will be more supply than demand on the grid since many supply resources are inflexible and may not be able to ramp down their generation level.[8] Supply curtailment is emerging as a solution to this need for downward flexibility. In 2014, there was only 19 gigawatt-hours of curtailment, or roughly 0.01% of total electricity supplied. Certain RPS contracts have curtailment rights, where the supplier can still be paid the previously agreed power price under contract up to a certain percentage of

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[5] In the future, demand response programs could also be used to induce short-term increases in load.

[6] The $55/kW-year figure is based on PG&E's Capacity Bidding Program. The $120-130/kW-year figure could be as high as $200/kW-year if the plant was really only used for <100 hours per year.

[7] Gross load is total electricity load for a given hour, while net load is gross load minus supply from solar and wind.

[8] Additional quantitative details are provided in section 1 of the appendix.

curtailment. Similar to demand response, paying for a small number of curtailed megawatt hours (even though the energy is wasted) will be economically favorable to building new resources such as storage (a source of downward flexibility), which would be far more costly.

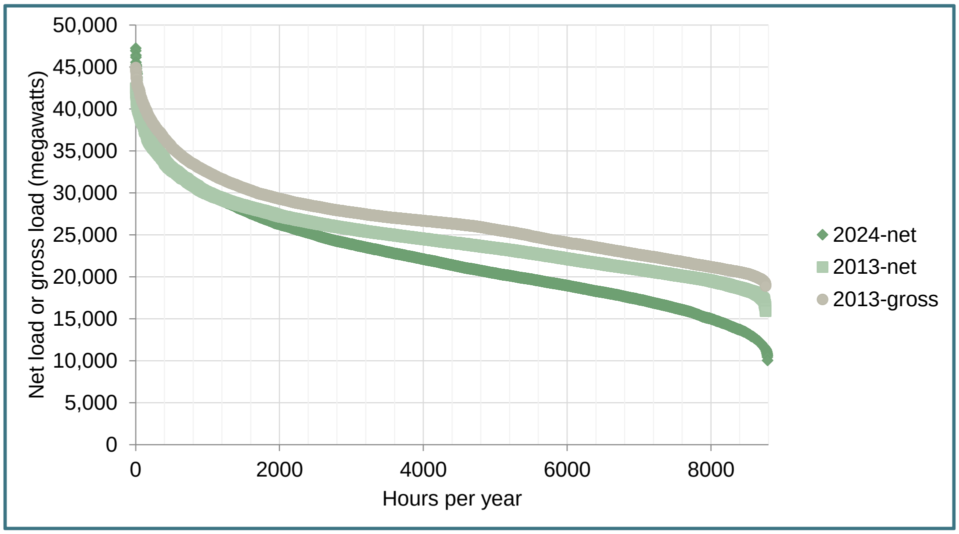

Figure 2: Load duration curves for gross load (2013) and net load (2013 and 2024)

But flexibility on a large scale is more difficult and costly to implement

While demand response should remain an economically sound resource for avoiding the need for capacity in a relatively small number of hours, this is not the case for curtailment and downward flexibility in a high solar future. In their report on a 50% RPS, EThree projects overgeneration to increase greatly in both magnitude and frequency under a 40% RPS and a 50% RPS as shown in Figure 3.

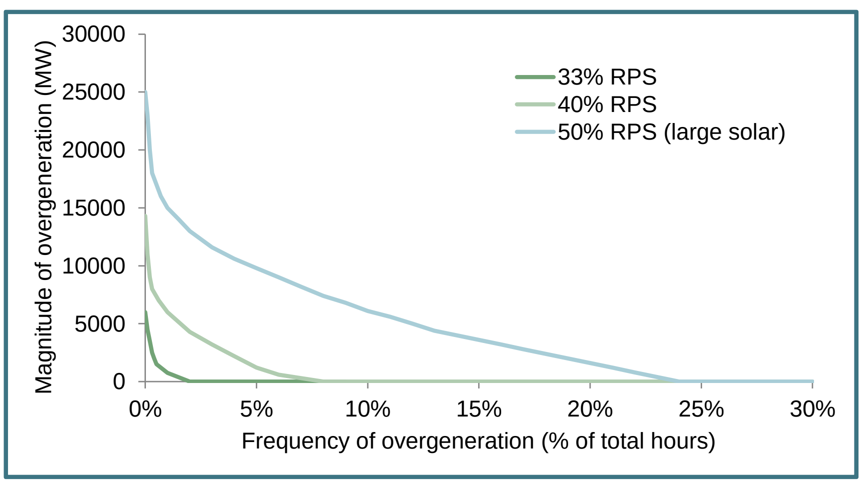

Figure 3: Frequency and magnitude of overgeneration events under different RPS scenarios

Under a high solar scenario, solar capacity would be overbuilt in order to meet the RPS because of the high amounts of overgeneration that would occur. If there were less overgeneration, however, there would not be less need to overbuild solar. EThree modeled the following potential solutions to the overgeneration: energy storage, enhanced regional coordination, advanced demand response (thermal storage or rate design), and a more balanced portfolio of renewable resources instead of a high solar scenario. Each solution was modeled at a level of 5,000 megawatts. Overgeneration, while not completely solved by the various measures, was reduced by 55-61%. The overall incremental cost of the 50% RPS (relative to a 33% RPS) was estimated as shown in Table 1. There are two important takeaways for the purposes of this analysis: 1) the relative costs of the different solution cases and 2) the cost assumptions used in producing the solution scenarios.

<table>
<tr><th rowspan="2"></th><th rowspan="2">50% RPS large solar</th><th colspan="3">Solution cases – large solar with:</th><th rowspan="2">50% RPS balanced portfolio</th></tr>
<tr><th>Energy storage</th><th>Enhanced regional coordination</th><th>Advanced demand response</th></tr>
<tr><td>Low cost scenario ($ billion)</td><td rowspan="2">8.0</td><td>6.5</td><td>4.6</td><td>4.7</td><td rowspan="2">5.2</td></tr>
<tr><td>High cost scenario ($ billion)</td><td>8.6</td><td>5.4</td><td>6.8</td></tr>
<tr><td>Overgeneration (GWh/yr)</td><td>12,000</td><td>5,000</td><td>4,700</td><td>5,000</td><td>5,400</td></tr>
<tr><td>Low cost assumption</td><td rowspan="2">N/A</td><td>Pumped hydro $375/kW-yr</td><td>Paid $50/MWh to export</td><td>Load shift w/ rate design $0/kW-yr</td><td rowspan="2">N/A</td></tr>
<tr><td>High cost assumption</td><td>Batteries $787/kW-yr</td><td>Pays $50/MWh to export</td><td>Thermal storage $413/kW-yr</td></tr>
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Table 1: Incremental revenue requirement scenarios for 50% RPS scenarios and various solutions to renewables integration, relative to the revenue requirements for a 33% RPS (EThree, 2014)

While the storage solution case resulted in the highest cost scenarios, the enhanced regional coordination and balanced portfolio cases resulted in the lowest cost scenarios. Relative to the energy storage scenario, the advanced demand response scenario saves $1.8 billion. However, there are some caveats with respect to the cost assumptions. The current cost of batteries ($787/kW-year) is used in the high cost scenario modeling for storage, yet this cost is expected to fall. Also, the low cost assumption for advanced demand response is $0/kW-year for load shifts due to rate design, when there will be some cost associated with this rate re-design, including marketing, education, and potentially even information technology costs.

These scenarios provide helpful goal posts for understanding the potential relative costs of different solutions. In reality, it is likely that a mixture of these solutions will be used, and a more detailed model would be needed to determine the resulting cost to ratepayers. There could be a scenario where the cost of storage falls but the cost of implementing demand side flexibility also turns out to be low, and as a result, both solutions can be deployed cost effectively and the amount of overgeneration can be reduced even further. Since the scenario involving demand-side flexibility offers the potential to have low costs, it is important to explore the boundaries of the assumptions used and find the true potential for demand-side measures in reducing overall flexibility requirements. The next two sections will explore this question, first looking at demand-side programs such as energy efficiency and distributed generation and second looking at retail pricing.

Programs for a High Solar Future

Energy and capacity costs are changing rapidly, so program planning for energy efficiency and distributed generation needs to adjust quickly to align with the future of avoided costs.

Demand-side programs, like energy efficiency and demand response, have long played a role in avoiding capacity. Likewise, they will play a role in avoiding flexible capacity. Demand-side programs are approved by the CPUC so long as they are cost effective – that is, that the benefit to cost ratio of the proposed program exceeds 1. The avoided cost calculator, designed by EThree, compares the costs of a specific program to its benefits. Avoided cost categories include energy, ancillary services, emissions, generation capacity, transmission and distribution capacity, and RPS. There is discussion to add flexible capacity to this list.

The last update of the avoided cost calculator for energy efficiency was in 2011, but the costs for wholesale energy are changing rapidly with the onset of solar. More regular updates of the calculator, with particular attention to these costs, are needed to ensure accurate program justification. Forecasts of where wholesale energy prices are headed in a high solar future can help inform the direction in which demand side programs should begin heading.

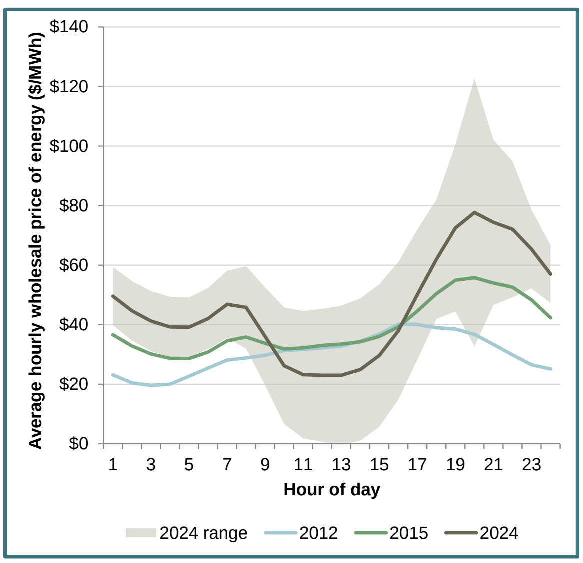

Figure 4: Evolution of wholesale energy prices

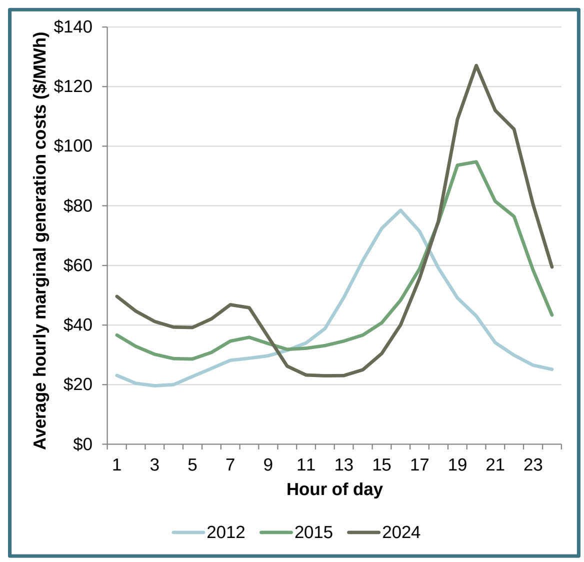

Figure 5: Evolution of marginal generation costs (energy plus capacity)

Figure 4 shows past wholesale energy prices for 2012 and projected values for 2015 and 2024 (under a 33% RPS). These values are hourly prices, averaged over an entire year, though the range for 2024 (plus or minus one standard deviation) is also shown. The average wholesale energy price was $30 in 2012 and will be $39 in 2015 and $46 in 2024. The cost of capacity is added to the wholesale energy price in Figure 5 to get an average hourly marginal generation cost. The increasing impact of solar can be clearly seen. Not only is the average cost of generation going to increase, but the timing of the peak capacity is moving from 4pm to 8pm on average, though this will vary seasonally. The following two examples show how projected prices should factor into the programmatic design of demand side management programs.

Example 1: Energy efficient lighting

Lighting is a ubiquitous technology that has different load profiles for different customer groups; commercial indoor lighting is mostly used during the day, while residential indoor lighting is mostly used at night. As the net peak load moves into the evening, the applications that use proportionally more energy at night relative to the day should become more cost effective. Figure 6 shows the daily average load profiles for commercial outdoor lighting and residential indoor lighting. In both incidences, a high proportion of the demand occurs in the evening hours when peak capacity is going to be for the foreseeable future.

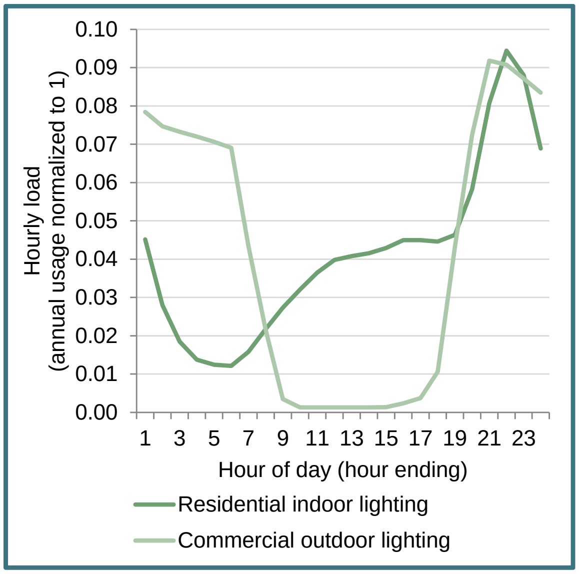

Figure 6: Load profiles for residential indoor lighting and commercial outdoor lighting

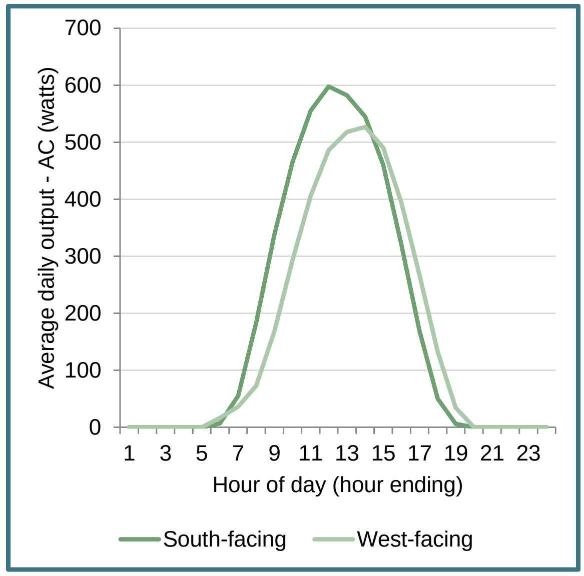

Figure 7: Output of south-facing vs. west-facing rooftop solar system (1 kW DC rated)

Multiplying the load profiles by the energy and capacity prices (actual for 2012 and projected for future years) produces the expected annual energy and capacity costs seen in Table 2. The avoided energy and capacity costs (benefits) increase for residential indoor lighting and commercial outdoor lighting by 27% and 73%, respectively, when using 2015 expected energy and capacity prices as opposed to 2012 prices. The values improve even further when using 2024 expected prices, which assume a 33% RPS. Overall, as the amount of solar on the grid increases, the need for upward flexibility increases in the evening when the sun goes down, and thus the value of efficiency measures like this will also increase.

	2012	2015	2024
Residential indoor	$44.28	$56.32	$66.29
Commercial outdoor	$31.82	$55.04	$72.42

Table 2: Evolution of annual energy & capacity costs (from Figure 5) for 1 megawatt hour of lighting demand

Example 2: West-facing rooftop solar

According to data from the California Solar Initiative, about 71% of rooftop systems between 0-10kW face south (somewhere between southwest and southeast) while 20% of systems face west (somewhere between northwest and southwest).[9] Figure 7 shows the output of a hypothetical 1 kW system based on whether that system faces south or west. A west-facing system would have one major wholesale energy and capacity related benefits which is to produce more energy in the afternoon and early evening when energy prices are higher.

	South-facing	West-facing
Total annual generation (MWh)	1.58	1.40
Total annual avoided costs	$60.37	$60.13
Avoided costs (4-7pm)	$6.59	$13.78

Table 3: Generation and avoided costs for south and west-facing rooftop solar system

Multiplying the output profiles of the rooftop solar systems by the 2015 projected energy and capacity prices (from Figure 5) produces total annual expected avoided energy and capacity costs. The west-facing system produces 11% less energy than the south-facing system. However, the avoided costs are roughly the same. In particular, the avoided costs for late afternoon and early evening generation on the west-facing system are 109% bigger than those of the south-facing system.

Overall, the west-facing systems are more valuable than the south-facing systems from a system perspective, and therefore the utility may want to play a role in educating or incentivizing customers to install west-facing systems. For homeowners with east-west roofs, they would not need an incentive, as if they are to go solar it would be best on the west-facing roof. For homeowners with both south and west-facing roofs, there may be potential to incentivize them to install more panels on the west-facing portion of their roof.

[9] For west facing systems, 17% are between west and southwest while 3% are between west and northwest.

Pilots for time of use products with higher peak/off-peak price ratios need to be conducted to determine the demand side's overall potential contribution to solving flexibility needs. Enabling technologies and improved education will be key factors to increase those contributions.

There is general agreement among the research and academic literature that retail electricity product differentiation (time of use, critical peak pricing, real time pricing, and others) can improve electricity grid operations and planning (Woo, et al., 2014). There is a need for better understanding of demand side price elasticity among different customer groups, and how that elasticity may change when aided by enabling technologies, different dynamic pricing approaches, and behavior change. Time of use (TOU) pricing could potentially have a very large role to play in shifting load away from the evening and into the day to coincide better with peak solar production. This would have the benefit of reducing both the need for downward flexibility during the day and the need for upward flexibility in the evening.

Scenario: the potential for large customers to increase load during the day

As mentioned in the previous section (Figure 4), the ratio between the on-peak and off-peak wholesale energy prices is rising from roughly 2.0 in 2015 to 3.5 in 2024. Assuming retail rates took on a similar ratio in a TOU pricing structure, the relative increase or decrease in demand would be based on the customer's substitution elasticity – that is, the amount the customer would substitute relatively inexpensive off-peak consumption for relatively expensive on-peak consumption. Naturally, a higher elasticity combined with a high price ratio will produce the highest change in demand as shown in Table 4.

	Demand reduction (on-peak)			Demand increase (off-peak)		
Peak/off-peak price ratio ⟶ Substitution elasticity ↓	1.2X	2X	3.5X	1.2X	2X	3.5X
0.05	-0.01	-0.02	-0.03	0.01	0.01	0.02
0.10	-0.02	-0.03	-0.06	0.02	0.01	0.04
0.15	-0.03	-0.05	-0.10	0.03	0.02	0.06
0.20	-0.04	-0.07	-0.13	0.04	0.03	0.07

Table 4: Change in demand as a function of substitution elasticity of demand and peak/off-peak price ratio[10]

To understand how much these changes in demand would help reduce the needs for upward and downward flexibility requires knowledge about the existing load shape for customers. Figure 8 shows the average aggregate hourly load shapes for residential as well as commercial and industrial (C&I) customers in PG&E's service territory. As an entire customer class, the load shape of C&I customers is relatively flat though the load shape of different customer segment and sectors will vary widely. The daily peak in the mid-afternoon is only 33% greater than the nighttime 'valley'. A TOU product with an evening peak period would help move more demand

[10] Basic details on the calculations can be found in section 6 of the Appendix.

out of the evening and into the day. In the case of a small price ratio and small elasticity, demand would only increase by 1% or an average of 65 megawatts during the daytime period. This number is calculated based on the 2-3pm hour in Figure 8 where C&I demand is roughly 6500 megawatts. In the case of the largest price ratio and highest elasticity, demand would increase by 7% or 450 megawatts. This latter number would be a modest contribution toward the 5,000 megawatts of downward flexibility (increased load) modeled by EThree and mentioned in the previous section. When considering that PG&E only accounts for 40% of California's electricity demand on average and assuming that it was thus only responsible for 2,000 megawatts of downward flexibility, then the contribution is more significant.

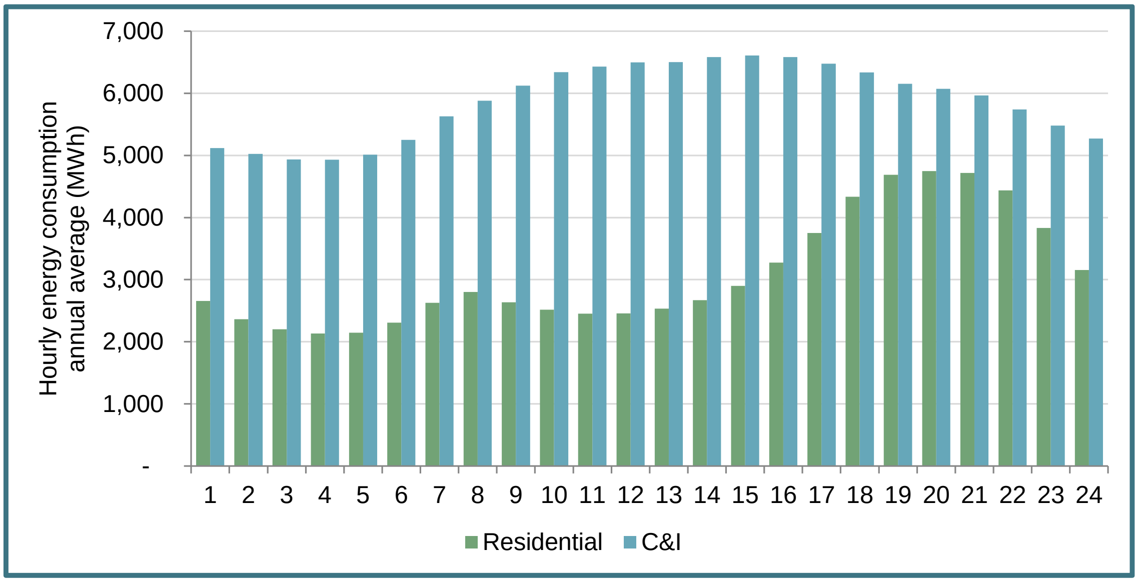

Figure 8: Aggregate hourly load shapes for PG&E residential and C&I customers based on an annual average

Current retail prices and customer attributes lead to low price responsiveness

The conditions in the scenario just mentioned are wildly optimistic but provide a goal post for potential. In reality, the current TOU rate peak/off-peak price ratio is only 1.2 for many C&I customers in PG&E service territory, though it is as high as 2.2 for some. For customers with a 1.2X price ratio, they would pay roughly $0.16/kWh for on-peak electricity and $0.13/kWh for off-peak electricity. TOU rates are mandatory, however, for C&I customers. For residential customers, the TOU rate is voluntary and has a price ratio of nearly 2.5. There are millions of residential customers but in total they only account for 35% of annual electricity consumption. C&I customers, on the other hand, are fewer in number but account for 65% of consumption.[11]

Customer class	Nature of TOU rate	Peak/off-peak price ratio	Percentage of annual electricity consumption
Residential	Voluntary	2.5	35%
C&I	Mandatory	1.2-2.2	65%

Table 5: High-level summary of time of use rates for PG&E customers

[11] Section 3 of the Appendix contains a more detailed explanation of PG&E's TOU products and upcoming changes.

Since the price ratio is so small, evaluations of whether customers make time-based shifts have been difficult for the TOU product for C&I customers. In its 2014 evaluation, PG&E found that there was no observed time-based load shift, though a very small reduction (1.5-2%) in overall electricity consumption (conservation effect) was observed across both peak and off-peak periods for small and medium-sized business customers. Other evaluations of critical peak pricing and TOU products show mixed results with load reduction impacts in the range of 3-14%. Only one study measured the substitution price elasticity; the result was -0.07 and was statistically significant. That study had a peak/off-peak price ratio of 5x for critical peak pricing and 2x for TOU. Details can be found in section 5 of the Appendix.

Potential price responsiveness is also going to vary across different customer segments, as C&I customers have a wide variety of load shapes as shown in Figure 9. Small and medium-sized business customers, which have average peak load consumptions of 3 kW and 35 kW respectively, have a peak shape with off-peak consumption at night roughly equal to half of peak consumption during the day. In contrast, the largest C&I customers (denoted by T for transmission in the figure) have an average peak load consumption of 4,000 kW and a very flat load profile.

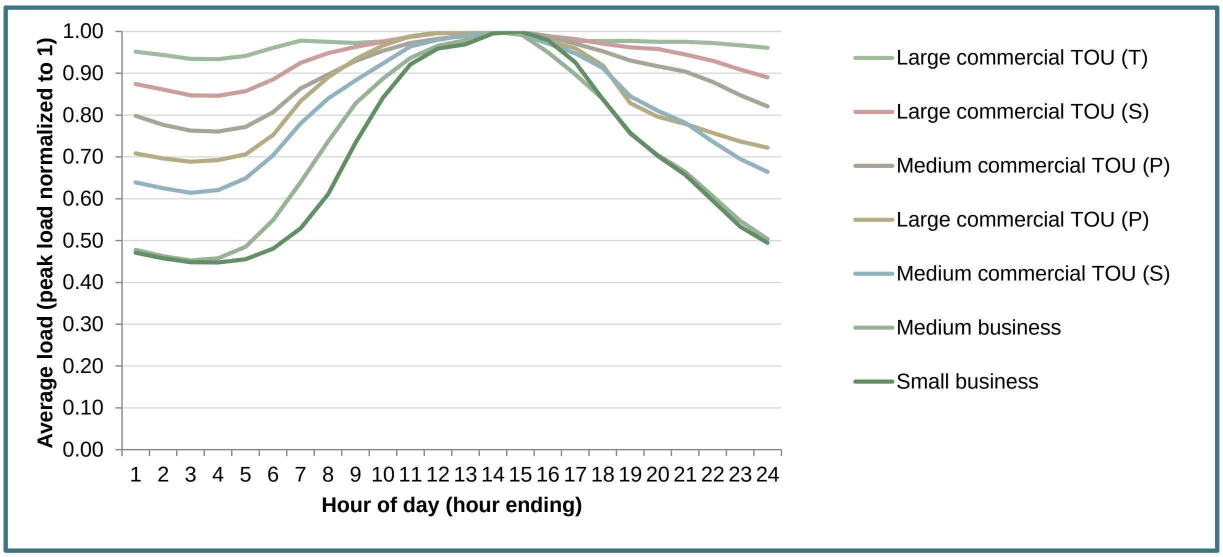

Figure 9: Aggregate hourly load shapes by C&I customer class based on an annual average[12]

The largest customers may actually have some incentives to spread electricity use evenly throughout the day given their demand charges. Demand charges, based on the amount of demand coincident with peak, encourage customers to spread their power usage (kW) over as much time (hours) as possible leading to a relatively flat energy consumption (kWh), especially in customers with very high demand for whom electricity is a large portion of their operating expenses (Woo, et al., 2014). It is likely that other factors are at play, however, that have to do with the particular industrial processes and economies of production for large customers. If a customer has large manufacturing equipment, they usually run it at full capacity to minimize operations and maintenance costs and maximize their return on investment for that equipment.

[12] The S, P, T in the graph refer to whether the customer is connected to the secondary (S) or primary (P) voltage distribution grid or the transmission grid (T).

Considering these facts, it may be difficult to get the largest customers to shift more load into the day and away from the evening.

On the residential side, a relatively comprehensive survey done in 2012 by the Brattle Group looked at 74 pricing experiments across the country involving dynamic pricing and time of use pricing. The study found that the amount of demand response rises with the peak to off-peak price ratio but at a declining rate. Enabling technologies (such as smart thermostats) were also included as a binary variable, and overall price responsiveness increased when using an enabling technology. Peak reductions varied from 2% to 24% for TOU pricing, from 2% to 47% for TOU pricing with enabling technologies, from 6% to 50% for critical peak pricing, and from 7% to 54% for critical peak pricing with enabling technologies. Figure 15 and Figure 16 in the section 4 of the Appendix show supporting figures from their study. Substitution elasticity in the different experiments ranged from -0.07 to -0.40. This is a very large range but variables such as climate, marketing and education, and history of dynamic pricing (that is, whether customers had exposure to dynamic pricing in the past) were not able to be controlled for this survey study even though they all likely have some impact (Faruqui & Palmer, 2012).

Overall, there is an evolving understanding of residential and C&I customer substitution elasticity. More studies are needed to accurately determine the potential responsiveness of different customer groups so that an overall contribution to demand-side flexibility can be calculated and incorporated into grid planning.

Possibilities: Enabling technologies and education to improve demand flexibility

Though it seems there is really a mixed bag of evidence for customer responsiveness, there are opportunities to improve substitution elasticity through the use of enabling technologies as well as improved education and marketing from the utility. In general, enabling technologies help customers make their demand for energy more flexible. At the residential level, this could include smart charging plugs for electric vehicles that only charge when the price is low and smart thermostats that pre-cool your home before prices spike. For C&I customers, an enabling technology could include a water storage tank that is cooled during off-peak hours so the cool water can be used during higher price on-peak hours to cool a large commercial office building or warehouse.

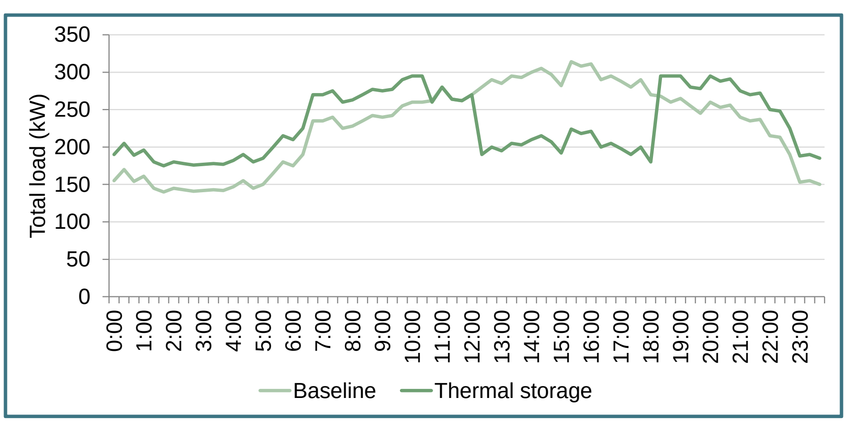

Figure 10: Thermal energy storage system to reduce on-peak electricity consumption

An example of such a system is shown in Figure 10. This example illustrates a hypothetical thermal storage system at a grocery store, which pre-cools refrigerant during off-peak times and then runs off that thermal storage during on-peak times (12-6pm in this case). The demand increase is around 35 kilowatts during off-peak times, and the demand reduction is 90 kilowatts during on-peak times. Overall, the total energy consumption will remain roughly the same, but the shifting will realize between $15,000 and $30,000 in savings per year (depending on the size of the system and grocery store) from avoiding demand charges and higher on-peak energy prices.

On the education side, there are many opportunities to do improved education and marketing around TOU pricing. In implementing a TOU program, there are likely to be firms that will have a hard time shifting their consumption or may not even be aware of the price risk they face. In fact, even for the real-time pricing programs around the country, only one third of the programs have a feature to help customers identify strategies to manage price risk (Barbose, et al., 2005).

A recent study used a subset of the data from a FERC survey on TOU pricing[13] (44 utilities including one from California – the LA Department of Water and Power) to perform hypothetical experiments on how high potential demand reductions could be if customers made some adjustments in their production schedules. The study split customers up into three groups: 1-shift, 2-shift, and 3-shift companies depending on how many production shifts the company has on a given workday. Then, they modeled two scenarios relative to a base scenario of flat rates:

- Scenario 1: TOU pricing
- Scenario 2: TOU pricing plus firm shifts production times to take advantage of low prices

		1 shift	2 shifts	3 shifts
Average (44 utilities)	Scenario 1	-11%	-10%	-3%
	Scenario 2	37%	14%	-3%
LADWP	Scenario 1	-25%	-19%	-4%
	Scenario 2	18%	17%	-4%

Table 6: Energy savings (positive) or extra energy costs (negative) based on number of production shifts and scenarios of TOU pricing (Wang & Li, 2015)

As highlighted in blue in Table 6, the savings are highest for customers with one or two shifts who are able to shift their production to take place at the lowest price times. If they do not time shift their production, then electricity costs increase. This points to the fact that utilities need to both educate customers on TOU pricing as well as target customers with potential flexibility in production with additional marketing to take advantage of the TOU pricing. The study also showed that the TOU programs with a sufficiently larger ratio of on and off-peak prices and relatively short on-peak periods were the most popular among industrial customers, as these factors enable the customer to be able to take advantage of low price periods. For customers with three shifts (running 24 hours a day), the benefits are not apparent, but the costs are also minimal in most cases (Wang & Li, 2015).

[13] More details are included at the end of section 5 in the Appendix.

Another opportunity that will leverage both enabling technology and customer education is electric vehicle charging. Electric vehicles could contribute to making flexibility problems even worse (by charging during the evening) or they could contribute to solving those problems (by charging during the day. Rates and technology can help ensure that electric vehicles will play a smart role in the smart grid. Programs can be set up to incentivize and streamline daytime charging at workplaces, multi-unit dwellings, and single family homes. The enabling technology for electric vehicles, smart chargers, will be key to turning an electric vehicle's charging function on and off. Ideally, the utility will be able to have control over at least a portion of these smart chargers so it can optimize user charging for convenience, price, and grid needs. Smart charging infrastructure adoption will take some time. In the meantime, customer education about TOU rates available for electric vehicle users will ensure that charging does not take place during the evening period, as evidenced in Figure 11, which shows current charging patterns for PG&E customers with and without TOU rates.

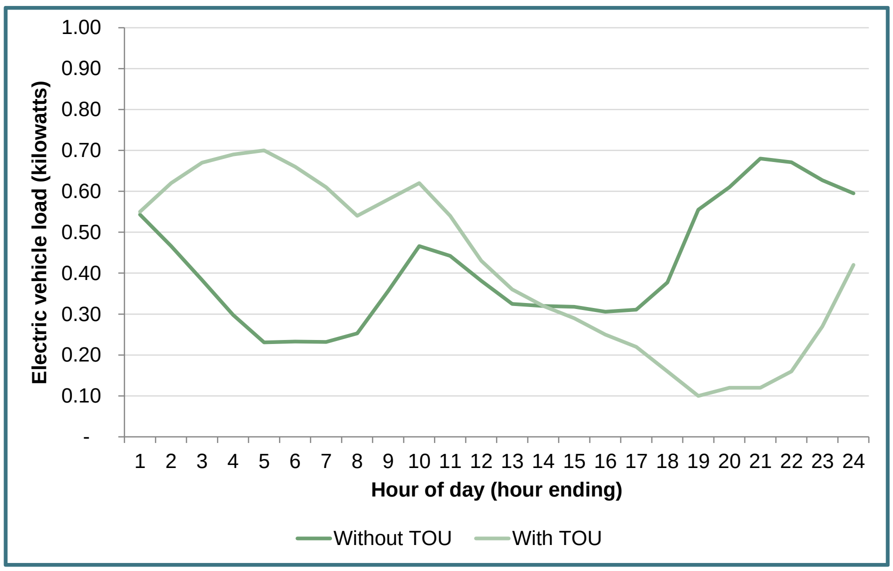

Figure 11: Electric vehicle charging patterns with and without TOU rates and workplace charging

Some customers may want to save money with TOU rates but not have the time or bandwidth to monitor their energy consumption very closely using enabling technologies. One solution could be to have every customer on a flat rate and then offer discounts if the customer installs enabling technologies (smart chargers, smart thermostats, appliance controls, etc.) that the utility can control within certain preset parameters. For example, the flat rate would be $0.20/kWh, but if the customer had a utility-controlled smart thermostat, then their rate would be reduced to $0.18/kWh (Florek, 2012). This type of rate could potentially have more widespread acceptance than TOU rates.

This section has provided just a few examples of how enabling technologies and education can improve potential customer substitution elasticity such that customers will be able to shift their electricity demand to the lowest price times. Higher elasticities will lead to greater reductions in flexibility needs for the grid, as the lowest price times will coincide with daytime solar production in the near future.

The Politics of Demand Side Flexibility

While TOU pricing – one of the best options for decreasing the need for flexibility – is politically difficult to implement due to cross subsidization and lack of an industry lobby, any measures that help increase customer elasticity (such as enabling technologies and improved outreach) will improve chances of political success.

California is host to myriad hearings and rulemakings which provide the regulation for the state's electricity sector. Regular forums held at the California Public Utilities Commission (CPUC) and California Energy Commission (CEC)[14] support reliability and cost effectiveness for the electricity grid that serves Californians as well as larger state legislative policy goals (such as AB-32 and the RPS). The suite of solutions available for power system flexibility is discussed in both regulatory and legislative forums.

The full potential for demand-side measures, such as TOU pricing and energy efficiency, to address flexibility issues at a lower cost than supply-side measures is not yet fully understood. Yet, even if they had the potential to save ratepayers billions of dollars, the prospect for implementing them is largely tied to two factors: 1) the balance of political forces at play in these regulatory and legislative forums and 2) the extent to which a measure causes cross subsidization. Cross subsidization is where one group of ratepayers may pay relatively more than another group for a particular measure. Overall, these two factors will mean that certain measures will receive widespread popular support, others will cause heated political debate, and some may go entirely unnoticed. The next two sections detail these two factors at play.

Cross subsidization leads to political difficulties for TOU pricing

Technology alternatives for solving flexibility issues have associated costs and benefits, and the political prospects of a given alternative are tied to how those costs and benefits are spread among ratepayer groups. In particular, if two ratepayer groups are receiving an unequal set of benefits and costs, there is more likely to be political gridlock or a watered down outcome.

The renewable portfolio standards and storage mandate[15] are examples of alternatives where the costs and benefits are spread across all ratepayers (colloquially referred to as "peanut butter"). As a result, these types of alternatives are easily institutionalized and politically popular to support (lower right quadrant of Table 7).

In arrangements where the costs are distributed to all ratepayers but a specific group is receiving the benefits (lower left quadrant of Table 7), the beneficiaries have a strong incentive to organize and therefore often have a very strong political lobby. The rooftop solar sector is a

[14] Including the Long-Term Procurement Plan, Resource Adequacy, General Rate Cases, Energy Efficiency, Demand Response, and Integrated Energy Policy Report

[15] The storage procurement mandate requires 1,300 MW of storage by 2020 in California, with specific goals for all three major investor owned utilities as well as specific goals for storage at the transmission, distribution, and customer side levels.

prime example of this. In the case of net energy metering, one of the main policies which supports the adoption of solar, the benefits are concentrated for those who get rooftop solar while any additional costs (often related to these systems' impact on the distribution system) are distributed to all ratepayers. Ratepayer advocate groups have argued against cross-subsidization, and the reform of net energy metering has been under heated debate for some months now as a result. PG&E has just applied for funding for 25,000 new electric vehicle (EV) charging stations, which may also have a similar cross-subsidization effect between EV users and non EV users.

Costs ↓ Benefits→	Concentrated	Distributed
Concentrated	Balancing area	Dynamic pricing
Distributed	Rooftop solar EV charging infrastructure	RPS Storage

Table 7: Distribution of costs and benefits to ratepayers for changes to the electricity system

Solutions with concentrated benefits and concentrated costs (upper left quadrant of Table 7) can be institutionally difficult and politically unpopular when benefits and costs fall on different groups and there are explicit wealth transfers. New transmission or increases in electricity trades in and out of the California electricity system might cause such a situation in the near-term. For example, one solution to overgeneration is to pay utilities in neighboring states like Nevada and Arizona to take the excess solar power in the real-time market. This results in additional costs for California ratepayers and additional benefits for other states' ratepayers. Situations like this could be possibly avoided with longer-term planning and more established market rules governing the trades to ensure an even distribution of costs and benefits between ratepayer groups.

Lastly, there is the situation of concentrated costs and distributed benefits (upper right quadrant of Table 7), where the benefits of the alternative would be receive by all but a select group of customers, who will then have incentive to organize strongly against the alternative. Dynamic pricing has faced opposition at times from groups that may face higher bills due to a time of use or critical peak pricing program, including a portion of industry, low-income groups, and the elderly. The benefits will be distributed across all other ratepayers, however, and it should lead to a more cost-efficient electric grid. The end effect, however, is that TOU pricing faces tougher political prospects compared to the RPS or storage mandate.

TOU pricing lacks strong lobby while facing opposition

Political support follows the patterns of cross subsidization closely. The legislation that created the RPS and storage procurement mandate received broad political support (always greater than 60% and often closer to 70%; see Table 8), given that there is no cross subsidization.[16] AB 327 legislated reform of residential tiered pricing as well as net metering to ensure less cross subsidization between residential customer groups. The bill also delayed the implementation of

[16] There will also additional benefits to California, including job creation, which is very important to politicians.

default residential TOU pricing for fear of cross subsidization. The bill received broad political support. Since nearly every citizen is an electricity customer as well, politicians will usually support bills that try to limit cross-subsidization or bills with both distributed costs and benefits.

	Senate		Assembly	
	For	Against	For	Against
SB X1-2 (RPS)[17]	26	11	55	19
AB 2514 (storage mandate)	22	13	48	27
AB 327 (NEM reform, TOU delay, etc.)	24	12	74	1

Table 8: Votes for and against various legislation concerning electricity system alternatives

In addition, politicians will also pay attention to specific interest groups, and likewise those interest groups will lobby politicians to align with their goals. The rooftop solar, utility scale renewable energy development, and electricity storage industries have well developed and increasingly powerful lobbies. In contrast, dynamic pricing does not have a major industry lobby, though a small group of new startup companies in the space that are providing enabling technologies (for example, smart thermostats, home area network devices, and certain types of storage) have a growing interest in the space, including Nest and Ohmconnect. Many economists in academia, the CPUC, and select environmental advocacy organizations (for example, Environmental Defense Fund) have been strong advocates for more dynamic pricing. The apparent lack of industry lobby may be related to the fact that there are fewer physical assets to be built in a world with more dynamic pricing. There would be less need for construction of additional supply of flexible resources, and therefore less rent-seeking from industrial lobbies. Enabling technologies do also offer opportunities for profit, however, and therefore, dynamic pricing should be a growing area of focus for industry lobbying.

Political prospects for TOU pricing can improve with technology, education

The General Rate Case (GRC) is the main regulatory forum through which rates and dynamic pricing options are addressed. Ratemaking generally follows a duality of principles:

1. Cost causation: Rates should be set according to the marginal cost of generation and cause a reduction of peak demand.
2. Customer acceptance: Rates should empower and engage consumers to conserve or shift energy consumption in order to reduce peak demand.

The program and pricing sections of this report showed how cost causation would indeed cause a reduction of peak demand as well as a decrease in the need for downward flexibility (in the

[17] This particular Senate Bill was for the 33% RPS, while prior versions established the 20% RPS.

case of pricing). Customer acceptance is really the key then, and it is directly tied to the cross-subsidization issue.

Enabling technologies, as well as improved outreach and education, will improve the political prospects for TOU pricing, because they will both increase demand elasticity for customers. If the elasticity increases, either the amount of money a particular customer could save will increase or at the very least the amount of money a particular customer would lose will decrease. Overall, the set of customers that are expected to lose money on a TOU rate is relatively small. Other measures, such as the ability to opt-out of the TOU rate, can also always be offered as a means for political compromise.

Appendix

1. Details on the magnitude and type of flexibility needs in a high solar future

Figure 12 shows the average daily solar power generation in 2014, peaking at around 4,000 megawatts (MW). This will grow to an average of around 13,000 MW under a 33% RPS, with a maximum possible amount of over 16,000 MW. The net load, which is the total demand for energy minus wind and solar generation, will fluctuate throughout the day at levels the electricity grid has never before seen. Figure 13 shows how the onset of solar causes very deep dips in net load during the day, with the dips becoming even more pronounced for a 40% RPS and especially during the month of April on days when it is very sunny but the demand for energy is relatively low.

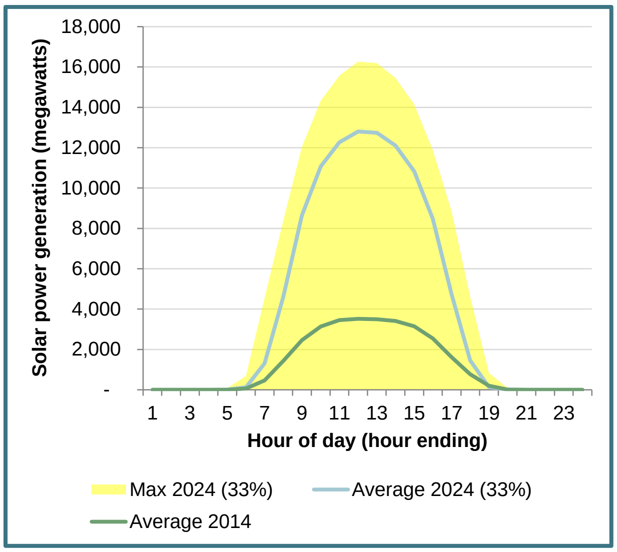

Figure 12: Solar generation in 2014 (actual) and 2024 (projected under 33% RPS)

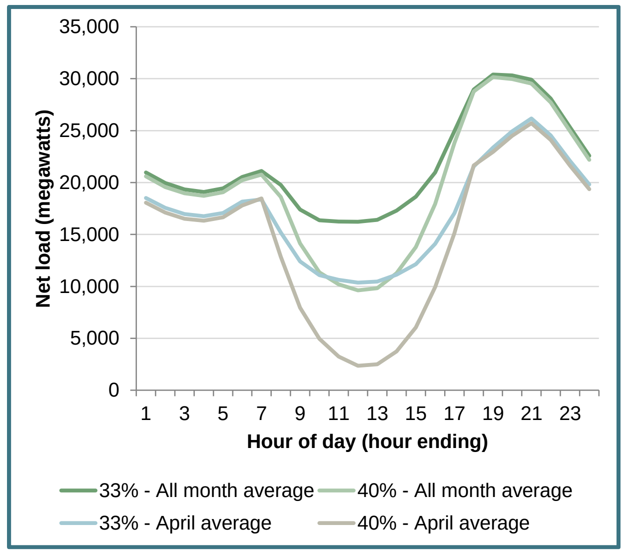

Figure 13: Projected average daily net load in 2024, for 33% and 40% RPS

CAISO reports that three major conditions will emerge: 1) steep ramps in the evening (upward flexibility); 2) overgeneration risk (downward flexibility); and 3) decreased frequency response (CAISO, 2013). For example, a report by consulting firm EThree on a higher RPS found that the need for downward flexibility would be as high as 5,600 MW under a 40% RPS and 15,000 MW under a 50% RPS (EThree, 2014).[18]

Figure 14 shows a more detailed supply picture for 2020 under a 33% RPS, with the right photo depicting the now well known "duck" curve as the space between gross and net load looks like the tail, belly, and neck of a duck. While net load is total load minus wind and solar, the adjusted net load also subtracts out nuclear and certain hydropower resources. This is because California's remaining nuclear facility is not structured to provide flexibility, while in "wet" years when there has been a lot of rain and snowfall, the hydropower resources often must run due to environmental and economic conditions and are thus also not considered flexible resources. As

[18] The numbers quoted here are 99th percentile. The absolute extreme maximum observed for downward flexibility is 14,000 MW and 25,000 MW for 40% and 50% RPS, respectively.

solar continues to increase under a higher RPS, the remaining set of resources (mostly natural gas power plants) that must ramp up and down daily to meet low morning demand and high evening demand will become increasingly stressed. The net load peak capacity is also moving from its historic position around 3-5pm to a position of 6-8pm, depending on the season. On the commercial side, energy on the wholesale markets will be worth very little during the daytime hours, except for in summer when demand is higher.

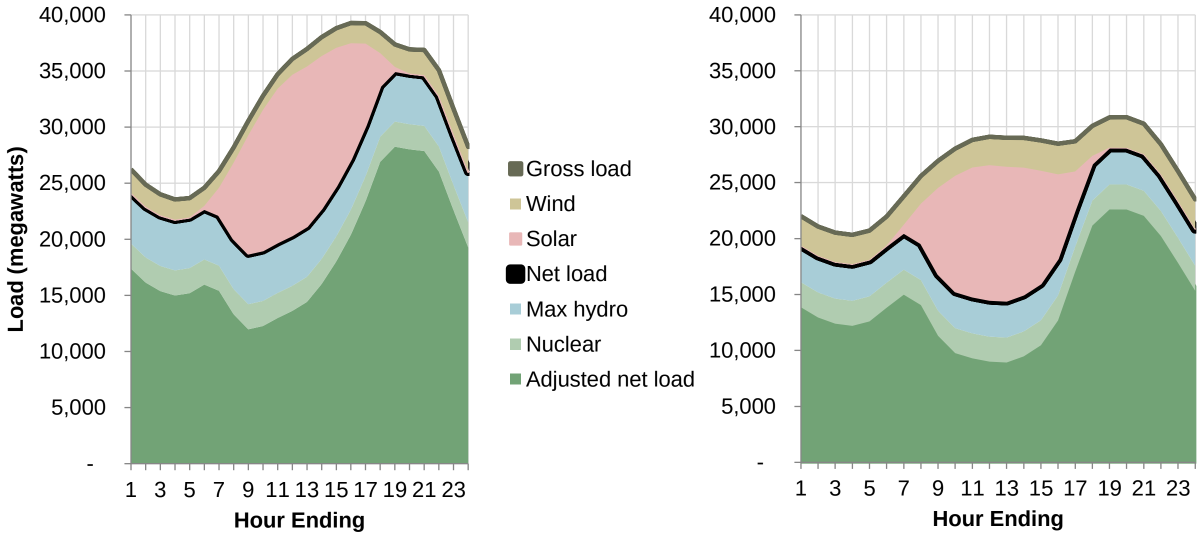

Figure 14: Average summer and winter load and supply projections for 2020 under a 33% RPS

2. Long-term planning approaches to flexibility

Wholesale energy market prices are usually insufficient (too low) to induce investment in new generation capacity, thus there is a need for a separate capacity market, or resource adequacy (RA) requirements as is the case in California (Woo, et al., 2014). Generally, this is because a wholesale energy market would only occasionally allow very high energy prices, but even these high prices would not provide enough income to justify building the capacity needed to meet infrequent periods of high prices. Now, flexible capacity requirements are being introduced in addition to capacity requirements due to a similar market failure. The RA requirement is 115% of peak demand in a given year. The flexible RA requirement (called effective flexible capacity or EFC) is currently defined as the maximum three hour ramp in a given year plus 3.5% of peak demand for that year.

The RPS procurement process looks at both the cost of integrating renewable energy when procuring new renewables as well as the cost of procuring flexible resources. The renewable integration cost adder (RICA) has two components: fixed and variable. The variable component is \$4/MWh for wind and \$3/MWh for solar. The fixed component is equal to the marginal increase (decrease) in flexible resource requirements for every megawatt of wind or solar capacity added, which is then multiplied by the projected price for those flexible resources.

The long-term procurement plan (LTPP) identifies the long-term capacity and flexible capacity needs on a 10-year horizon. A standardized demand scenario is used and then scenarios involving various supply side assumptions are run to determine a range of potential outcomes with respect to capacity needs. Current long-term planning uses a demand scenario developed by the CEC that takes into account various new customer-side technologies such as rooftop solar and electric vehicles as well as energy efficiency and demand response resources, including existing dynamic pricing. Demand-side price elasticity is a standardized assumption though this may change as the CEC plans to introduce scenarios for time of use pricing with a range of price elasticity. There is still some doubt amongst utilities about the reliability of customer response to price signals.

In the current LTPP process, there has been insufficient evidence to authorize additional flexible or system capacity procurement through 2024. That is to say, there is sufficient capacity within existing resources to meet current upward flexible capacity requirements. For now, there are plenty of generation resources to “turn on” in order to meet the evening peak net load, though this could easily change as new renewables come online. While day-ahead and real-time needs for downward flexibility had been identified in the early LTPP (for 2022) under the existing 33% RPS,[19] there is little agreement on how to develop models which will accurately distinguish what the exact requirements and attributes of a downward flexibility resource should be. More investigation on efficient solutions to overgeneration events is needed. CAISO has asserted that additional deterministic studies of the 33% and 40% RPS scenarios – with no renewable curtailment allowed – must be conducted to provide a complete set of book-ends to characterize the nature and extent of need for flexible resources. These additional studies are to be released in May 2015. The LTPP process will also investigate the potential magnitude and value of solutions to overgeneration and, based on the results of that effort, consider recommendations and policies to alleviate overgeneration. Initially identified CPUC policy and program areas that could address overgeneration include but are not limited to energy storage, rate design (including time of use pricing), vehicle electrification, demand response in real-time markets, refined RA rules, distributed generation, and renewable energy contract modification.

As for the projection of prices for flexible resources, there are three components: a short-run cost, a long-run cost, and flexible RA premium. In the short run, there is plenty of flexible capacity at around $50/kW-year that is economically efficient to keep online in the next five years to meet upward flexibility capacity needs. The flexible RA premium will help increase capacity prices in the medium term (2020-2030) until it reaches the long-run cost of capacity, which is the cost of building new capacity as opposed to keeping existing capacity online for longer periods of time.

3. Existing dynamic pricing products at PG&E

There is an existing set of dynamic pricing products at PG&E, including time of use (TOU) pricing and critical peak pricing (CPP) for residential, commercial, and industrial customers. The existing programs are outlined in Table 9 based on four parameters: default vs. opt-in (voluntary

[19] Overall, there is a regular need for 900 MW of downward flexibility, and a small number of hours that have a larger need of 1600-2800 MW. As mentioned previously, these needs will become much more significant under higher levels of RPS.

customer signup) rate structure, the time window for the higher price, the ratio between peak and off-peak prices, and the status of any potential product changes (such as the time window).

Product	Parameters	Residential	C&I
Time of use pricing (all year or May-Sept.)	Default/optional	Optional	Default
	Time window	1-7 pm → 4-9 pm	12-6 pm
	Peak/off-peak price ratio	2.5	1.2-2.2[20]
	Status of changes	Time window: in progress; Default: wait until 2018/20	Time window: wait until 2017 GRC
Critical peak pricing (10-15 days/year)	Default/optional	Optional	Default
	Time window	2-7 pm	2-6 pm
	Peak/off-peak price ratio	6.0	2.7-6.4
	Status of changes	Time window: in progress; Default: wait until 2018/20	Time window: wait until 2017 GRC

Table 9: High-level summary of existing dynamic pricing products in play at PG&E

For residential customers, there are opt-in TOU and CPP (known as Smart Rate) products. The TOU product establishes a peak price and an off-peak price, while the critical peak price is a much higher price for up to 15 summer days but customers receive a small discount for the rest of their energy. The time window is currently changing for the TOU product from 1-7pm to 4-9pm to align with the expected change in net load peak. The peak to off-peak price ratio is 2.5 for the TOU product and around 6.0 for CPP. For the opt-in TOU product, load reductions of 6-8% have been measured for the peak period, with small amounts of snapback after the peak period.[21]

As mentioned previously, AB 327 mandated that TOU products remain opt-in for now and cannot become default until 2018. In 2016, PG&E plans to begin more widespread marketing of opt-in TOU pricing. In 2018, PG&E plans to begin a pilot for defaulting customers on to TOU products and then expand TOU pricing to all residential customers in 2020. In their recent proposed decision on residential rate reform, the CPUC expressed its thoughts on this timeline, saying: "In a world where the Nest programmable thermostat was the most hyped tech holiday gift for 2014, the argument that it takes three years to design a pilot that could lead to increasing participation in time of use pricing to meaningful levels is not reasonable." (CPUC, 2015)

Small and medium business customers are currently being defaulted on to TOU pricing. Large commercial and industrial (C&I) have already been defaulted onto TOU pricing. The peak to off-peak ratio is very small though. The current TOU pricing understates the actual wholesale cost differential between peak and off-peak periods. Due to this fact, there is likely cross subsidization between customers who consume disproportionately high quantities when wholesale prices are high and those who consume disproportionately low quantities at those times (Borenstein, 2007). Changes to the time window (which is currently 12-6pm) will have to wait until the 2017 general rate case. Whether customers make significant shifts in the time of their energy consumption has been a difficult question to evaluate, though overall a small

[20] A1 and A10 customers (small and medium business) have peak/off-peak price ratios in the range of 1.16-1.23x, while E19 and E20 customers have ratios between 1.3x and 2.2x depending on the size of the customer, with larger customers generally having a smaller ratio.
[21] Snapback refers to an increase an energy use in the off-peak period immediately following an on-peak reduction.

conservation effect (1.5-2%) has been observed over time across both peak and off-peak periods amongst small and medium business customers. The peak to off-peak price ratio for C&I's CPP product is much higher ranging from 2.7 to 6.4.

In summary, the time window changes are in progress for residential customers but will have to wait until the 2017 general rate case for C&I customers. The option to default the switch for residential dynamic pricing products will have to wait until 2018 to pilot and 2020 to implement. The peak to off-peak ratio for C&I TOU, however, remains small. Given where the daytime vs. nighttime wholesale price differential is heading, there will be a need to eventually increase the ratio based on cost causation principles, but it is uncertain how much customers will respond to higher ratios. On the residential side, there is uncertainty about how much customers will be able to reduce or shift load as the peak time window changes and opt-in rates become default.

4. Figures from price responsiveness study on residential dynamic pricing

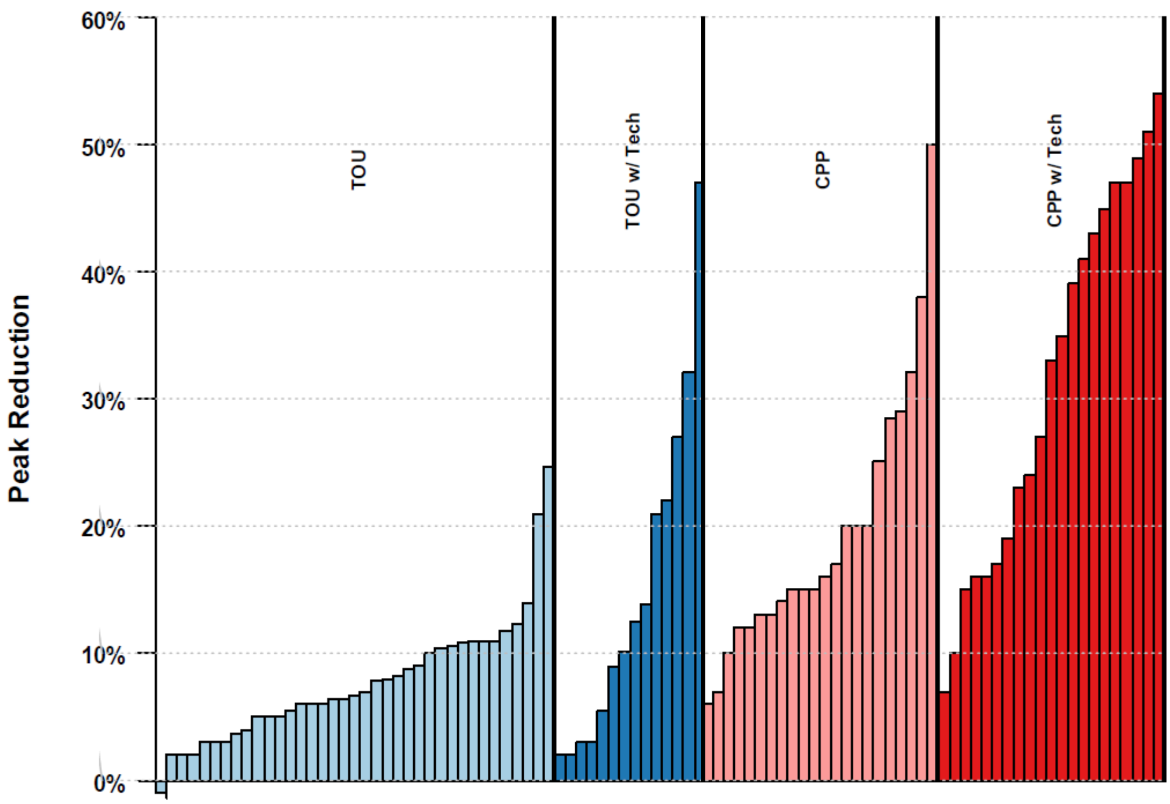

Figure 15: Impacts from Pricing Tests, by Rate Type and Presence of Enabling Technologies (Faruqui & Palmer, 2012)

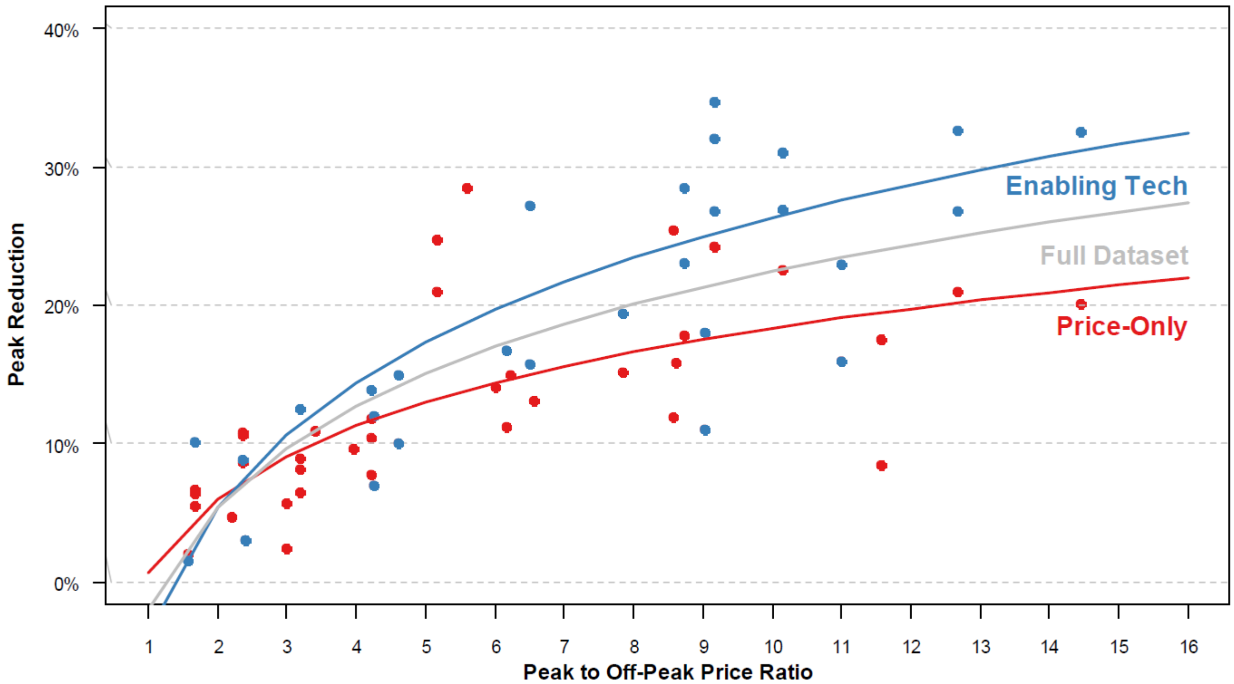

Figure 16: Impacts from Pricing Tests by Peak to Off-Peak Ratio with the Fitted Logarithmic Curves, Segregated by Presence of Enabling Technologies (Faruqui & Palmer, 2012)

5. Results of various evaluations of TOU and CPP products for C&I customers

A number of California-specific studies have been done on its CPP and TOU programs for C&I customers (including the statewide pricing pilot study published in 2005, a couple interim studies, and a recent study published in 2013. The results of these studies show load reduction impacts in the range of 3-14% (see Table 10), some of which are statistically significant and some of which are not.

The statewide pricing pilot study looked at a limited number of C&I customers (up to 200 kW in demand) in Southern California Edison's (SCE) service territory. That study found load impacts of 6-9% on critical peak price days with a peak price roughly 5 times higher than the standard rate. The impacts increased to around 14% when a smart thermostat and central air conditioning were present in the sample. That study also looked at TOU pricing with a peak/off-peak price ratio of 2.0, where impacts ranged from 4% to 9%. The study found that the substitution elasticity was -0.07 (statistically significant). The authors note that the results should be viewed cautiously, given the small sample size and significant variation in model coefficients across the two summers (Charles River Associates, 2005).

In 2009, a study of CPP pricing on PG&E customers found an average impact of 8.4 MW or 3.3% across 12 events and 642 participating customers, with events ranging from 4 MW to 12.6 MW. Retail stores responded up to 12.9%, but manufacturing sites only responded 4.3% and offices, hotels, and health services only 1.7% (Braithwait & Hansen, 2012). In a prior study by the same author on 2006-2007 CPP events, it was found that manufacturing actually had the greatest price responsiveness in contrast to the 2009 study (Braithwait, 2009).

Lastly, an evaluation of CPP events for roughly 1700 C&I customers in 2011 and 2012 found that in aggregate, customers reduced demand by 6.9% in response to a peak price nearly 10 times their normal peak price, delivering on average 30.2 MW of demand reduction. The overall range for the 12 events was 4.7-9.4% and 21.0-41.2 MW. The differences between individual day results and average event day results, however, are not statistically significant. Demand reductions were concentrated within three industry segments – Manufacturing and Wholesale, Transport & Other Utilities, and Agriculture – which delivered average reductions of 11.6%, 20.8%, and 13.7%, respectively, and overall account for 41% of program enrollment and 85% of the estimated demand reductions (Bode, Churchwell, & George, 2013).

Study	Product	Year	Number of customers	Load Impact (%)	Load Impact (MW)
(Charles River Associates)	TOU	2003-2004	132 (SCE)	4-9%	N/A
	CPP			6-9% 14%[22]	N/A
(Braithwait & Hansen)	CPP	2009	642 (PG&E)	3.3%	8.4
(Bode, Churchwell, & George)	CPP	2011-2012	~1700 (PG&E)	6.9%	30.2

Table 10: Summary of California relevant TOU and CPP evaluation studies for C&I customers

Lastly, a 2012 FERC survey studied 149,140 C&I customers enrolled in 408 TOU programs, provided by 204 utilities in the U.S., with a total potential peak demand reduction of 6421 MW. Within that set, there were nearly 27,000 customers in California-based TOU programs, with a potential peak demand reduction of 310 MW (Wang & Li, 2015).

6. Modeling demand impacts from different price ratios and substitution elasticities

In order to produce the numbers in Table 4, a simple calculation was done using the following equation:

$$\varepsilon = \frac{\%\ change\ in\ demand}{\%\ change\ in\ price} = \frac{\%\ change\ in\ demand}{\frac{\Delta P}{P}}$$

The hypothetical substitution elasticity, ε, was multiplied by the change in price and divided by the midpoint between the original price and the new price. The new prices were modeled based on the price ratios and so that the new off-peak and on-peak prices multiplied by demand would maintain a revenue constant to the revenue under the previous pair of prices, assuming demand also stayed constant. The change in the off-peak price is much smaller than the change in the on-peak price, thus the demand reductions and larger in magnitude than the demand increases. The end price pairs used were: 1.2X: $0.130/kWh and $0.160/kWh; 2X: $0.114/kWh and $0.227/kWh; and 3.5X: $0.089/kWh and $0.312/kWh.

[22] With enabling technology: smart thermostat.

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