BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U 902 E) for Approval of its Proposals for Dynamic Pricing and Recovery of Incremental Expenditures Required for Implementation.	Application 10-07-009 (Filed July 6, 2010)
Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design	Application 19-03-002 (Filed March 4, 2019)

RESPONSE OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) TO THE ADMINISTRATIVE LAW JUDGE'S OCTOBER 2, 2019 RULING DIRECTING SAN DIEGO GAS & ELECTRIC COMPANY TO FILE AND SERVE A DYNAMIC PRICING WORKSHOP REPORT

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October 29, 2019

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Pursuant to the California Public Utilities Commission's ("CPUC" or "Commission") Rules of Practice and Procedure and the Administrative Law Judge's ("ALJ") October 2, 2019 Email Ruling Providing Draft Agenda and Directions for October 15, 2019 Workshop On Dynamic Pricing, San Diego Gas & Electric Company ("SDG&E") respectfully submits this Response to the above ruling. Ordering Paragraph ("OP 2") of the October 2, 2019 Ruling states that "San Diego Gas & Electric Company (SDG&E) shall file and serve a report that summarizes the presentations and discussions that occur during the October 15, 2019 [dynamic pricing] workshop; this workshop report shall be due no later than October 29, 2019."

Per the ALJ Ruling, SDG&E hereby submits the Dynamic Pricing Workshop Report and Summary of Presentations and Participant Comments (Attachment A) along with parties' presentations from the Workshop (Attachments B through L).

Respectfully submitted,

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ATTACHMENT A

DYNAMIC PRICING WORKSHOP REPORT AND SUMMARY OF PRESENTATIONS AND PARTICIPANT COMMENTS

Dynamic Rate and Real Time Pricing Workshop Report
Summary of Presentations and Participant Comments
October 15, 2019 (A.19-03-002)

CPUC Remarks – Commissioner Shiroma

Commissioner Shiroma introduced the workshop and indicated that the CPUC has a responsibility to align rates, cost causation, affordability, and rate stabilization, all while focusing on decreasing Green House Gas (GHG) emissions.

In closing remarks, Commissioner Shiroma indicated that any intervenor testimony on real-time pricing or dynamic rate proposals needs to be as thorough as possible and provide ample supporting research and regulatory citations.

Summary of Presentations

California Public Utilities Commission (CPUC)

Objectives:

- Discuss existing dynamic rates and pilots offered by SDG&E and other jurisdictions.
- Provide parties an opportunity to share preliminary proposals regarding dynamic rate options.
- Explore implementation issues related to the feasibility and design of dynamic rates.

Expected Outcomes:

- All Party Workshop report to be filed by SDG&E that includes Summary of the presentations, proposals and discussions.
- Parties may file comments regarding the workshop and in response to the workshop report.
- Intervenors may address the workshop and the workshop report in their testimonies.

See Full Presentation (Attachment B)
Topic: Introductory Slides

San Diego Gas and Electric (SDG&E)

- Provided a historical overview of 2003 – 2005 Statewide Pricing Pilot (SPP), an overview of 2018 CPP results and SDG&E's Hour X residential TOU pilot, and an overview of SDG&Es Petition for Modification of Critical Peak Pricing (CPP) for small non-residential customers.

SPP Pilot

- The SPP statewide pilot came about as a result of the 2001 energy crisis, where the wholesale energy market experienced extreme price volatility. It appeared that the lack of any dynamic pricing available made the problem worse. The SPP involved about 2,500 customers from California's investor-owned utilities (IOUs) and ran from July 2003 to December 2004. Several different rate structures were tested. These included a traditional time-of-use rate (TOU), where price during the peak period was roughly 70 percent higher than the standard rate and about twice the value of the price during the off-peak period. The SPP also tested two varieties of critical peak pricing (CPP) tariffs, where the peak period price during a small number of critical days was roughly five times higher than the standard rate and about six times higher than the off-peak price.

From this pilot, SDG&E learned that:

- There is a statistically significant variation in hourly impacts within pricing periods.
- Peak period impacts reach their maximum at 5:00 p.m. in all climate zones.
- There is much variation in the size of the impacts across climate zones (warmer climates have larger impacts).
- However, the aggregate impacts at the period level did not differ appreciably from the impacts in the March 16th Impact Evaluation report.
- A similar approach can be used to assess hourly impacts for the CPP-V rate, both for residential and small commercial and industrial (C&I) customers.
- Changes since early 2000s in technology, customer behavior, and change in TOU periods may result is different lessons learned today.

2018 CPP Load Impact Results

- In 2018, CPP results for SDG&E's small C&I customers were relatively small at just under 1% during a CPP Event. Small C&I was defaulted to CPP in 2016.
- Results for SDG&E's medium and Large C&I CPP was 6.9 MWs for approximately 1200 customers, medium customers averaged 1.9 MWs for approximately 13,000 customers.
- SDG&E defaulted its large C&I customers in 2008, medium C&I defaulted in 2016.

Hour X Residential Opt-In TOU Pilot

- As part of the residential Opt-In TOU pilot, SDG&E created Hour X – a residential hourly dynamic rate. This rate was a proof of concept rate. It was complicated, and most participants were company employees with about 60 participants. Event hours varied in length.

Critical Peak Pricing Petition for Modification (PFM)

- SDG&E seeks to place new small business customers on a TOU-only rate, and they can elect to participate in the TOU-CPP if they choose. Existing customers would be unaffected.
- SDG&E found the current approach of applying CPP as the "default rate" for small non-residential customers has led to increased bill volatility, a corresponding increase in customer complaints, and a relatively insignificant reduction in load.
- CPP rates are current default rates for small commercial, medium and large (M/L) commercial and industrial (C&I), and Agricultural customers.
- CPP is a dynamic rate intended to motivate customers to reduce their electricity use during periods of high-system demand using price signals. In return for reducing their load during "event days," these customers receive lower rates throughout the remainder of the year.

CPP PFM Conclusions

- Customers' ability to reduce usage during critical peak pricing event periods is important to their success on an event-based dynamic rate.
- Many small non-residential customers do not have the operational flexibility to reduce their energy use during CPP events while continuing to meet the basic energy needs required to operate their business.
- Customers who knowingly choose an event-based dynamic rate are more likely to respond by reducing their energy use.
- Structural winning on a dynamic rate means that customers may benefit annually on a dynamic rate even if they are unable to reduce electricity usage during a CPP event.
- It is reasonable to establish a time-variant rate (without an event-based CPP feature) as the standard rate option for small non-residential customers initiating SDG&E service.

Vehicle Grid Integration (VGI) Pilot

- As of July 31st, 1,124 drivers are receiving the hourly price signal.
- SDG&E believes the rate has shown preliminary success at influencing drivers to shift their load during high pricing events. A load impact report will be available by April 1, 2020. Additional follow up details are provided below.
- There is a growing interest in hourly pricing and other mechanisms to incentivize drivers to shift their load. This is being studied through many different pilots and rate designs.

- The idea of having a mechanism to influence EV drivers to shift their load for either renewable generation or grid constraints is one that has been on the minds of many stakeholders for some time. BMW recently presented preliminary results of a pilot they had with PG&E to study this. They expect a full report to come out later in Q4. Additionally, as PG&E was ordered to file for a dynamic rate within 12 months.
- SDG&E offers another dynamic EV rate, the Public GIR. This rate is only applicable for the Green Shuttles Priority Review Project. It is very similar to the VGI rate; the only major difference is a much lower rate level for the circuit adder. It is similarly a pilot project. There are fewer than 10 customers participating in this pilot.

See Full Presentation (Attachment C)

Topic: SDG&E Current and Dynamic RTP Pricing

Southern California Edison ("SCE")

See Full Presentation (Attachment D)

Topic: Real Time Pricing and Transactive Energy

California Solar and Storage Association ("CALSSA")

- Day-ahead and real-time versions of RTP should be available as an option to all customer classes.
- SDG&E's Vehicle Grid Integration and Grid Integration Rates are good foundations for a more broadly available rate.
- RTP elements should include: actual CAISO prices at the sub-LAP level, a CPP adder to recover most generation capacity costs, no generation or primary distribution demand charges, other billing determinants generally follow otherwise applicable tariff.
- As a hedging option, customers should be able to reserve blocks of energy at the standard TOU rates.
- Utility needs to partner with vendors to connect customers with load management technologies.

See Full Presentation (Attachment E & F)

Topic: Dynamic Pricing in Other Jurisdictions & RTP Rate Proposals for SDG&E GRC

Public Advocates Office ("CalPA")

Any New Rate Designs Should Be Pilot Tested

Too little is known about the billing determinants of customers who will participate in innovative rate designs. Using the general class billing determinants to design critical peak pricing (CPP) or real-time pricing (RTP), which is specifically targeted to customers employing new technologies, may lead to revenue shortfalls and cost shifts that are not cost-based. Participants should not be allowed to keep the bill savings, which cause revenue shortfalls, that exceed grid benefits. Rates may have to be adjusted over time to reduce revenue shortfalls that are not cost-based.

Given that RTPs cannot be known in advance, RTP has the added problem that it is difficult to know how large a markup to apply to RTPs to recover generation capacity costs and the equal percentage of marginal costs (EPMC) scalar used to incorporate fixed costs into rates. These markups are likely to be almost as large as the RTP itself, making non-trivial revenue shortfalls and surpluses likely. The markup could be recovered in a TOU volumetric rate, but such a TOU rate would have almost as much influence on the bill as the RTP component itself. Alternative approaches include a two-part RTP, where RTP is only charged on increments and decrements of usage relative to baseline usage. But, determining that baseline usage is challenging, as it requires determining what a customer's usage would have been absent the rate. Allowing the customer to instead subscribe to a demand level could lead to customers undersubscribing, thus placing too much of their usage on the lower RTP that excludes the standard rate design markups.

Conducting a Pilot Might Help Avoid Unintended Consequences

One unintended consequence that has been observed in the storage element of the Self-Generation Incentive Program has been increased GHG emissions. D.19-08-001 has addressed this problem by requiring future SGIP programs to incorporate a GHG signal to reduce GHG emissions by five kg/kWh or be subject to incentive payment reductions.

Another possible unintended consequence is for the combination of incentives and bill reductions being larger than the actual reduction in utility costs caused by employing new technologies. Often the incentives and rates are designed separately, both using the same marginal costs, and this can lead to overcompensating customers. A special concern is with storage incentives paid to Net Energy Metering (NEM) customers given that the NEM export compensation rate is not cost-based and itself creates a disincentive for investing in storage.

The Pilot Should Estimate the Ultimate Level of Participation

The participation rate in RTP in California has been low. An RTP is a relatively small portion of the bill compared to generation capacity costs, delivery rates, and the standard rate design markups. The bill savings with RTP also may be very difficult to predict in advance, making a customer decision to invest in equipment to take advantage of RTP difficult. It also is unclear

how many customers have sufficient operational flexibility to accommodate RTPs or even CPP. The utilities should not offer rate options to which few customers would subscribe.

The Pilot Should Assess What Load Diversity Benefits Exist that Can Be Used to Reduce Rates

Past demand charge discounts to solar and plug-in electric vehicle customers have been justified based on their loads being non-coincident with the rest of the class. These discounts should not be permanent because, as such loads increase as a percentage of total class load, the diversity benefit decreases (e.g., solar and "duck curve" issues).

No demand charges exist for residential and small commercial customers partly because of the significant load diversity within those classes. In contrast, very large customers on dedicated feeders or circuits have almost no diversity at the distribution level. Thus, distribution non-coincident demand charges may remain relevant to them. It is unclear at what customer size level these diversity benefits decrease sufficiently to justify demand charges, and the pilot study should investigate this. In the interim, it is important that the class revenue requirements reduction, caused using Effective Demand Factors (EDFs) in revenue allocation, flow entirely to non-coincident demand charges in rate design.

SDG&E's demand charges could more accurately reflect EDFs if the Medium/Large Commercial and Industrial (M/L C&I) class were split into two, as PG&E and SCE have done. Alternatively, a questioner suggested placing EDF discounts in the M/L C&I tariffs that would vary based on the customers non-coincident load in each month. The costs and benefits of complicating the rate design would need to be considered.

See Full Presentation (Attachment G)

Topic: Challenges of Dynamic and Real Time Pricing

California Large Energy Consumers Association ("CLECA")

See Full Presentation (Attachment H)

Topic: Critical Consumption Period Proposal

WattTime

See Full Presentation (Attachment I)

Topic: MIDAS: Emission Focused Device Optimization

Schatz Energy Research Center / Lawrence Berkeley National Laboratory

- Pay-for-a-load-shape (P4LS) was one of several proposals for possible pilot approaches to organizing load shift as part of the Load Shift Working Group.
    - In the LSWG context, there were constraints that the proposals not be based on new rates.
    - Since this workshop is explicitly about dynamic/real-time rates, it is important to point out that this proposal may need to be restructured if it is deployed in the context of dynamic prices.

- P4LS envisions a program that sets a **grid-friendly target load shape** and pays incentives to customers who match it well. The inspiration was the 2025 California Demand Response Potential Study, which was completed in support of CPUC R.13-09-011.
    - The general concept is:
        - Utilities provide target load shapes that are updated periodically.
        - These targets could incorporate both energy market marginal prices and infrastructure costs (peak load reduction, etc.)
        - Customers modify loads and are compensated based on reduced cost to serve loads. The calculation of value could include avoided curtailment, reduced fuel costs, reduced need for capacity, etc. and would depend on a public process.
    - More details on the proposal are available in the presentation slides from the October 15, 2019 workshop and in the Load Shift Working Group Final Report.

- A core value P4LS attempts to capture is related to renewables integration, avoiding curtailment of installed and operational renewable power. We presented some updated information on curtailment in California as background:
    - Curtailment in CAISO has been increasing substantially in recent years, reaching a seasonal peak of ~7 GWh/day in Spring 2019 (a "lost value" of $300k/day based on an assumed $40/MWh replacement value for solar).
    - Curtailment in CAISO includes some days without curtailment and others with substantially more. The maximum daily curtailment was on May 27, 2019 (Memorial Day), with 39 GWh curtailed.
    - As curtailment becomes more frequent it is also more predictable. In 2019, there was mid-day curtailment on ~50% of the days in Jan-Feb and ~75% of the days in Mar-May. This implies that structural load shifting to increase loads in the middle of the day will tend to be a good strategy on most days in Winter and Spring. As more renewables are added to the grid, it becomes even more of a sure thing in these seasons and frequent curtailments will be expected year-round as well.

    - An initial assessment of various P4LS frameworks found that there are diminishing returns to more frequent updates in instructions. Compared to day-ahead updates, ~70% of the value to the grid can be achieved with monthly updated instructions. This initial assessment was based on simplified assumptions but indicates that there could be significant value provided by instructions that are updated more frequently than TOU pricing but less frequently than every day.

- In the context of dynamic/real time pricing, the structure of the P4LS concept would need to be adjusted, since customers would face prices that incentivize these improved load shapes, and there would be no "baseline" issue with determining appropriate customer compensation. The P4LS concept may still be appropriate for consideration as a model for incentivizing aggregators and third parties who support customers to better restructure and shift their loads.
    - Customers who shift loads according to instructions would experience bill savings since prices in California are correlated with other priorities like managing peaks, avoiding curtailment, and reducing operational CO_2 emissions.
    - Other work has identified that some customers (particularly residential and small commercial) may not have the sophistication to understand energy market prices and the implications of technology investment and operation on responding to these. Or, the bill savings may be too small to justify the effort it would take to do background research and implement upgrades to buildings and loads.
    - An aggregator could support these customers to be flexible, and it may be appropriate to pay incentives to these aggregators related to the improvements in response at those sites (similar to the way EE aggregators are paid to help push EE technology that is cost-effective). These incentive payments could be structured in a similar way to the P4LS concept originally conceived in the LSWG.

It is important to note that there is a natural affinity and linkage between P4LS and Pay for Performance EE, an emerging concept in EE where the time-value of savings is accounted for in program assessment.

See Full Presentation (Attachment J)

Topic: Pay for a Load Shape

Sunrun

- Utility and CCA Bring Your Own Device (BYOD)/rider tariff programs are designed for customers to respond to dispatch signals for coordinated aggregated response. Such programs in the Northeast and New York provide successful examples.
- Consider the impact/inequity of exposing customers to local/regional high pricing.
- Don't simply hope customers respond to high prices.
- Resources participating in BYOD programs are better suited for coordinated real-time dispatching than individual customers responding to real-time rates.
- BYOD programs encourage technology adoption and advancement.
- Protect customers unable to adopt new technology and exposed to real-time pricing.
- Don't forget about distribution hosting capacity coordination benefits and other multiple use applications benefit if coordinated at DSO/CCA domains versus system level.

See Full Presentation (Attachment K)

Topic: Bring Your Own Device Opportunities with Dynamic Rates

San Diego Airport Parking (SDAP)

- SDAP is a site host for SDG&E's ***Green Shuttle*** and the ***Power Your Drive*** pilot programs. Both pilot programs are on the piloted real time pricing plans, with a rate design similar to SDG&E's GRID Integration Rate ("GIR"). These rates consist of a flat volumetric base rate, plus CAISO day-ahead hourly market rates, combined with the CPP and D-CPP adder fees when events are triggered. The CPP and D-CPP components may be problematic for customers such as SDAP, who cannot shift demand to off-peak hours due to operational constraints.
- In addition, SDAP raised the question of whether capacity costs are double-counted in these rates:
- SDAP presented hourly CAISO market price data for July 24, 2018, showing that the CAISO market price exceeded 35 cents per kWh for 9 consecutive hours on that day, topping out at $1.01 per kWh.

- SDAP believes that the Marginal Energy Cost ("MEC") in a given hour is mainly determined by the heat rate (Btu/kWh) of the least efficient generating unit operating in that hour, multiplied by the cost of natural gas.[1]
    - Given that the CPUC's "low efficiency cutoff" for GHG estimation in the Avoided Cost Calculator is now 13,500 Btu/kWh, a natural gas cost of $10 per million Btu would yield an MEC of 13.5 cents per kWh.
    - The cost of NG is unlikely to exceed $24 per MMBTU in the foreseeable future. This NG price would translate to a maximum MEC of about 32 cents per kWh.
- For these reasons, SDAP believes that the CAISO market price exceeded the MEC for the 9 hours described above, as well as many other hours as identified by SDAP.
- SDAP believes that the excess of the CAISO market price above the MEC represents a "scarcity rent" and should be regarded as the collection of capacity-related costs in an energy-only market.
- For the above reasons, SDAP suspects that the GIR and similar RTP rates that include both a CAISO hourly market price and a (system) CPP adder result in double counting of generation capacity costs.
- SDAP is considering a proposal to change the GIR and similarly structured RTP rates to eliminate the potential for double-counting capacity costs.
- Finally, SDAP believes that the efficiency of the GIR and related rates could be improved by replacing the flat volumetric base rate component by a TOU volumetric rate.

AL-TOU-CPP has significant flaws that need correcting: The Two Halves of the AL-TOU-CPP Rate May Conflict

- AL-TOU-CPP is SDG&E's default rate for M/L C&I customers:
- AL-TOU-CPP consists of:
    - A Critical Peak Pricing (CPP) rate; and
    - A Base (T&D) rate consisting mostly of Monthly Demand Charges.
    - These demand charges exceed $24 per kW on a non-coincident basis and $17 per kW additional during peak TOU hours.
- The CPP Rate is intended for Demand Response.
- Non-Coincident Demand Charges support load flattening and may work against demand response.
- Monthly demand charges are not helpful for Demand Response, because
    - A customer may be faced with using storage or other load-shifting options to shave its monthly demand charge, or to respond in the CPP hours, but may not be able to do both,

[1] There are other much smaller components of the MEC, such as variable O&M costs, that can be neglected for the purpose of this argument.

- a CPP event may occur when the customer is nowhere near its typical non-coincident monthly demand, and
- a CPP event may occur later in the billing period than a particularly high billing demand, so the customer cannot expect any demand savings from responding to a CPP event.
- Since there is no cost-causal basis for high non-coincident demand charges, and demand charges are not well designed to encourage customers to shift load to lower-cost hours, every dollar that is recovered through a demand charge is a lost opportunity for encouraging efficient operation.

The Commission could and should, consider,

- Avoiding Monthly Demand Charges in T&D Base Rates when paired with CPP or RTP;
- Pairing volumetric TOU Base Rates rather than demand charge rates could be the best pairing for dynamic and RTP commodity rates.
- Alternatively, pairing a Daily Coincident T&D Demand Charge, with dynamic rate and RTP generation charges could work well.
- SDAP favors splitting SDG&E's M/L C&I class into separate Medium and Large customer classes, with an upper limit of 200 kW for the Medium class.
- SDAP believes that demand charges are not cost-based for customers under 200 kW because these customers have greater feeder circuit diversity relative to the Large C&I customers (e.g., > 200 kW).
- Medium commercial customers (under 200 kW) with significant EV charging loads should be allowed to opt onto rate schedules such as TOU-A, TOU-AP, or TOU-M with low, or no, demand charges.

SDAP recognizes that the CPUC has limited ability to affect FERC-jurisdictional retail transmission rate design,

- However, SDAP agrees with remarks made by SEIA in the August 27, 2019 workshop in this proceeding, that the CPUC can, and should, encourage the large IOUs to file proposals at FERC for retail transmission rate designs that build in more time dependence and limit reliance on demand charges. Reforming retail transmission rates in this manner would improve the ability of dynamic rates to elicit demand response.

See Full Presentation (Attachment L)
Topic: Incompatibility of Dynamic Rates and Demand Charges

Panel Discussion

Lawrence Berkeley National Laboratory ("LBNL")

- Need retail prices that better reflect the system conditions. Current rates need a stronger price signal to incentivize shifting loads to the consumer to use more energy during low GHG hours and having higher prices during high GHG/kWh.
- Let's look into SPP 2.0 as the next step - We need a Statewide Pricing Pilot 2.0 to revisit which price forms and incentives can get a persistent load shift response and what automation is needed to improve that response. We need to understand the impact on customer bills is and how to promote and evaluate the automation technologies available today and support their development.
- We need to use open standards-based communication for automated price response, which allows a more open market for automation and reduces potential stranded assets. We need to explore how to support different automation architectures and business models for third party technology support.
- Important to get a persistent response to dynamic pricing. We need longitudinal studies to evaluate long-term price response and how to enable shift technologies that are durable and reliable. We also need to collect data on technology characteristics and costs to ensure we understand how to create load shapes and modeling tools that describe what we see in the field.
- Can we eliminate demand charges all together? Is there some other price format that may be more effective? Perhaps subscription pricing where a customer pays for a block of power at one rate and exposes a small fraction of their load to the real-time price?
- Affordability - Need to continue to invest in EE in order to keep costs down. In case of EE control retrofits, we need to ensure that the integrated DSM concepts are available to customers so they have technology for EE and dynamic price response.
- Technology is available, but there are challenges with different customer types and end-use loads.
- Rates should be available in a machine readable format - something like an XML signal - that can communicate with automation and technology devices. This allows prices to devices.

San Diego Gas and Electric ("SDG&E")

- A proper incentive must be balanced with the recovery of the necessary fixed costs.
- We are in the process of rolling out and educating customers on TOU rates right now. Once a case history of TOU has been established, dynamic rates will be able to fill in gaps.
- TOU rates provide an opportunity to understand customers' elasticity around price signals.
- TOU rates also provide an opportunity to identify ME&O that is effective to send price signals to customers.
- Lessons learned from implementing TOU rates will help SDG&E to better understand how customers understand and react to various dynamic rates.
- Must balance cost vs. the cost effectiveness of these programs.

- One of the most important issues facing SDG&E is how to best address cross-subsidization inequities as new rates and/or programs are implemented.
- For example, does the status of one group of customers who can actively participate in a dynamic rate that has a higher upfront cost (e.g., the cost of solar panels and batteries), provide them an economic benefit at other customers' expense?

California Solar and Storage Association ("CALSSA")

- Level of granularity is important.
- RTP should be available as soon as possible, but we need piloting of ME&O and can consider targeting day-ahead to less sophisticated customer classes.
- Using a price signal reduces program complexity compared to programs that depend on a counterfactual baseline and lowers the barriers to participation.
- There may be winners and losers, but over time, if a customer actively participates, they should be better off because sustained price spikes or price drops eventually affect standard rates -- there's simply a lag in the impact on other rate schedules.
- It's clear that other states and jurisdictions can do this, so let's get the ball rolling.

Sunrun

- Sunrun supports the DSO/CCA model where resource participation and existing infrastructure is maximized to manage local energy needs and for all regional customers.
- Diversity of rates across a territory. How does the interplay between multiple rates vs. a few, support or hinder progress? The BYOD model is a simple customer opportunity that can modernize the existing and future DER fleet to protect all customers by mitigating regional high energy costs and future capacity infrastructure and RA investments.
- On rate stability – Sunrun defines stability as matching regulatory change to customers' ability to adopt new technology and to prevent regulatory uncertainty that can stall technology deployment, thus providing customer benefits and grid savings to achieve California's clean energy mandate. Adapting to change burdens both businesses' and the customers' ability to participate and make investments aligned with the needs of the grid. California's policy investments will drive technology innovation and manufacture production volume, enabling cost reductions and technology availability to be realized.
- Pricing on a more granular level is needed to target and manage local costs– this would be at the subLAP or P-Node level and utilize BYOD programs to manage these costs and future regional investments.
- The customer and power system will benefit being able to capture value from managing regional volatility and investment needs, with scheduled or real time dispatching with a 4-5 hour or less window within excess energy and ramping/peaking time domains.
- On bill financing for technology is valuable, but for technology that requires a larger investment like energy storage, can financing be written into the tariff – essentially sharing the risk and benefit between the utility and the 3rd party vendor?

Sunrun Responses to ALJ Kao October 2, 2019 Ruling

1. What technical and operational challenges must be overcome in order to make a dynamic rate using CAISO price data available to customers? What is the estimated cost of that work?

   Response: Day-ahead market price notifications such as signaling critical peak pricing is likely a more effective way for residential customers to be aware and respond to grid needs as opposed to telemetered real time pricing signals. As a compliment to critical peak pricing signals, Sunrun believes Utility and CCA Bring Your Own Device (BYOD)/rider tariff programs designed for customers to respond to dispatch signals for coordinated aggregated response to shield customers from local/regional high pricing will be more advantageous than simply hoping customer response to high prices.

2. For dynamic rates based on CAISO wholesale market price data, what are the advantages and challenges of using day-ahead vs. day-of and real-time CAISO prices?

   Response: Sunrun believes day-ahead pricing would be best used to alert customers of a critical peak pricing event and to notify aggregated DERs within utility/CCA BYOD programs that they will likely be dispatched in the real-time market. Resources participating in BYOD programs are best suited for coordinated real-time dispatching as opposed to individual customers responding to real-time rates.

3. Besides CAISO wholesale market price data, is there any other data, such as the GHG emissions intensity of the grid, that should be used as the basis for a dynamic rate? What are the advantages and disadvantages of these alternatives?

   Response: Sunrun believes GHG emissions are an important signal for customers to respond too given that the peak is carbon intensive and some customers may be more inclined to reduce load or participate in BYOD programs if the programs provide opportunities to avoid GHG.

4. What is the appropriate time interval for dynamic rates? What are the issues and challenges of implementing rates that are based on the CAISO real time market price that use an interval longer than CAISO real time market data? How will the differences in temporal granularity of pricing be reconciled?

   Response: A dynamic rate signal interval in 1-4 hour range is reasonable duration, but Sunrun believes utility and CCA programs are a better option to shield customers from high LMPs that are of long duration or seasonally persistent. Given that there is no single real-time market price, with possibly hundreds of locational Market Price signals within CAISO territory, we worry how customers will have enough historical and future knowledge of how their LMP changes daily and seasonally in order to wisely invest in technologies to manage their rates. Alternatively, Utility and CCA targeted BYOD

programs can be developed to shield the region from high prices as opposed to hoping individual customers respond. Without targeted BYOD programs, individual more affluent customers will install large generation and battery systems to shield themselves from high prices, while other customers in the region receive limited to no rate protection beyond how they may respond during the real-time pricing event.

5. Should dynamic rates focus solely on periods of overgeneration where CAISO wholesale prices are negative (i.e. critical consumption pricing), or should they seek to send critical peak price signals as well?

   Response: One potential benefit to focusing on critical consumption pricing only would be that there are no other capacity planning programs designed to address this need and a clear planning gap in reaching State clean energy goals, which could be filled through program creation. Customers can provide critical consumption and critical peak response, but not all customer technology solutions will be able to provide both services effectively. Given that we are learning, it likely makes sense to offer customers options for load shift, critical consumption, or critical peak services. Offering a mix of customer programs and pricing also allows for programs and pricing to be tailored more effectively for local grid needs.

6. Given that overgeneration events are a key driver in dynamic rate use and may be limited to a transmission constrained area, should certain dynamic rates be available statewide to all customers, regardless of local grid conditions?

   Response: Given the many LMPs within CAISO territory and seasonal loads, rates should be based on LMP, but given the future needs of these services it is likely prudent to offer statewide, so that a that customer knowledge and targeted investments can be made that align with the long term planning needs of the grid.

7. At which level of granularity should wholesale prices be sourced? Should it be the default load aggregation point (DLAP), the sub-load aggregation point (sub-LAP), price node (Pnode), or circuit substation-level? What challenges would the use of any sub-system level of granularity present in terms of design, implementation, and frequency of updates?

   Response: DLAP is likely best for day ahead critical peak pricing events, with BYOD programs also targeted at sub-LAP, Pnode, or circuit/substation level pricing.

8. How should distribution rates be treated in a dynamic rate scheme? To what extent should distribution capacity costs be included in a dynamic rate?

   Response: Distribution costs should be bundled within dynamic rates and should also be used as a planning tool to change behaviors through pricing and programs to avoid future investments.

9. Do SDG&E customers currently have the technology available to automatically take advantage of a dynamic rate?

   Response: Building off of existing Demand Response programs and DDIF solicitations, Sunrun believes there are current technologies available to meet the dynamic pricing needs of the grid as opt in programs but need a regulatory pathway to enable desired participation.

10. If most adjustments in a dynamic rate take place within the generation component of the rate, how will CCAs operationalize the rate if at all? Are CCAs capable of mirroring or otherwise designing a dynamic rate that its customers can take advantage of? What operational challenges do the CCAs face with such a rate? How much does the success and benefits of wider deployment of more dynamic rates depend on CCAs following suit?

    Response: Dynamic rates and BYOD programs are well suited for CCAs. These aggregated resources within CCA territories provide local capacity to take advantage of excess energy and peak, whereby they are investing in aggregate resources that shape regional load for the benefit of all customers.

11. What sorts of customer education, outreach, and technology adoption might be necessary to ensure eligible customers maximize the benefits of these rates?

    Response: Significant unless leveraged as a BYOD program.

12. What are the potential revenue collection and cost shift impacts of adopting dynamic rates and how can these impacts be managed while satisfying long term rate design and retail market development goals?

    Response: BYOD programs are designed for coordination by utility or CCA, creating an aggregation that shields all customers from high prices and captures value. We worry that LMI customers may be negatively impacted from cost shift if they are unable to invest in technologies that shield themselves from rates, thus we believe BYOD programs are superior as the aggregation capacity coordination lowers costs for all customers and not just those that can invest and respond to grid needs/pricing.

California Large Energy Consumers Assoc. ("CLECA")

- Real Time Pricing (RTP) proposals should be focused on aligning retail pricing for energy with the real-time CAISO prices for **energy (kWh),** and not include other costs
    - Retail rates for **peak** capacity (kW) are already reflected in the TOU rate design
    - Some parties' proposals would impact the collection of non-energy costs
- RTP proposals that utilize energy-only rate designs have an inherent problem because changes in consumption result in revenue cost shifts between customers for the fixed costs
    - Electric utility service consists of substantial fixed costs
- A properly designed demand charge is a useful tool to discourage adverse customer behavior
    - An energy-only EV charging rate cannot incent customers to charge multiple EV's sequentially; charging EVs simultaneously (at the wrong time) could have adverse impacts on the distribution system as EV adoption increases
    - (CLECA's critical consumption period was targeted to spring conditions when customer demand is lower than summer months, and time-related demand charges would still apply.)
- Impacts of the RTP rate designs need to be monitored for adverse effects, either to utility T&D cost or revenue cost shifting
- Energy Division should review how rate design proposals fit with the Rate Principles described in the Residential OIR.

WattTime

- Current rates are not doing enough to incent the proper behavior.
- Including a GHG curtailment estimate to further incent conservation or shifting usage to less carbon intensive periods.
- How heavily are we going to need to rely on automation?
- Need greater granularity from CAISO – what level of detail can CAISO provide while at the same time is appropriate for billing system capability and technology. Lacks data on curtailment and would like to see more of this.

Follow Up Questions and SDG&E Responses

1. SDG&E will be adding a load impact evaluation of the VGI hourly rate to its April 1, 2020 Load Impact evaluation and will be both estimating load impacts as well as providing a 10 year forecast as prescribed by the load impact protocols. Load impacts for the VGI rate impacts are currently not available.

2. "At which level of granularity should wholesale prices be sourced? Should it be the default load aggregation point (DLAP), the sub-load aggregation point (sub-LAP), price node (Pnode), or circuit substation-level? What challenges would the use of any sub-system level of

granularity present in terms of design, implementation, and frequency of updates?" – Question #7 of ALJ Kao's October 2, 2019 Ruling.

DLAP prices are available to the public on CAISO's website. The more that publicly available pricing information is used, the easier it is for third parties to validate. When prices are provided on a more granular level, there is a greater possibility that the data would be confidential. SDG&E has 1 DLAP, and no Sub-LAPS. The Pnode level would require changes to how customers are billed and would add to the level of complexity. SDG&E's customers would have to be segregated by Pnode and charged accordingly, based on Pnodes.

Next Steps

All parties may file and serve comments regarding the October 15, 2019 workshop and in response to the workshop report. Party comments regarding the October 15, 2019 workshop shall be due no later than November 12, 2019; intervenors may also or alternatively address the October 15, 2019 workshop and the workshop report in their testimony.

Reference

The presentations are accessible at the following url:
https://www.cpuc.ca.gov/General.aspx?id=6442462894

ATTACHMENT B

INTRODUCTORY SLIDES

Workshop on Dynamic rates and Real time Pricing

California Public Utilities Commission

October 15, 2019

Objectives for this Workshop

Objectives:

1) Discuss existing dynamic rates and pilots offered by SDG&E and other jurisdictions.
2) Provide parties an opportunity to share preliminary proposals regarding dynamic rate options.
3) Explore implementation issues related to the feasibility and design of dynamic rates.

Expected Outcomes:

- All Party Workshop report to be filed by SDG&E that includes Summary of the presentations, proposals and discussions.
- Parties may file comments regarding the workshop and in response to SDG&E's workshop report.
- Intervenors may address the workshop and SDG&E's workshop report in their testimonies.

Workshop Agenda

Session	Presenter	Time
Opening Remarks	Commissioner Shiroma	10:00 – 10:05 AM
Workshop Goal and Objectives	Masoud Foudeh (CPUC)	10:05 – 10:10 AM
SDG&E's Current Dynamic and RTP Pricing	Leslie Willoughby & Greg Anderson (SDG&E)	10:10 – 10:35 AM
SCE's Real Time Pricing, Transactive Energy	Mark Martinez (SCE)	10:35 – 10:50 AM
Dynamic Pricing in other Jurisdictions	Scott Murtishaw (CALSSA)	10:50 - 11:00
Challenges of Dynamic and Real-Time Pricing	Chris Danforth (Public Advocate office)	11:00 - 11:15 AM
Proposal: day-ahead and 5-minutes RTP	Scott Murtishaw (CALSSA)	11:15 – 11:45 AM
Critical Consumption Period proposal	Paul Nelson (CLECA)	11:45 – 12:00 PM
Lunch (Not hosted)		**12:00 – 1:00 PM**
MIDAS: Emissions Focused Device Optimization	Henry Richardson (WattTime)	1:00 – 1:15 PM
Pay for a Load Shape proposal	Peter Alstone (LBNL and Humboldt State)	1:15 – 1:45 PM
Bring Your Own Device opportunities within Dynamic Rates	Audrey Lee (Sunrun)	1:45 – 2:15 PM
Incompatibility of Dynamic rates and Monthly Demand Charges	Lisa McGhee (San Diego Airport Parking)	2:15 – 2:25 PM
Break		**2:25 – 2:30 PM**
Panel Discussion moderated by: Matthew Tisdale (Gridworks)	Jesse Emge (SDG&E) Audrey Lee (Sunrun) Scott Murtishaw (CALSSA) Paul Nelson (CLECA) Mary Ann Piette (LBNL) Henry Richardson (WattTime)	2:30 – 4:30 PM
Closing Remarks	Commissioner Shiroma	4:30 PM

ATTACHMENT C

SDG&E CURRENT AND DYNAMIC RTP PRICING

SDG&E GRC Phase 2
Dynamic Rates and Real Time Pricing

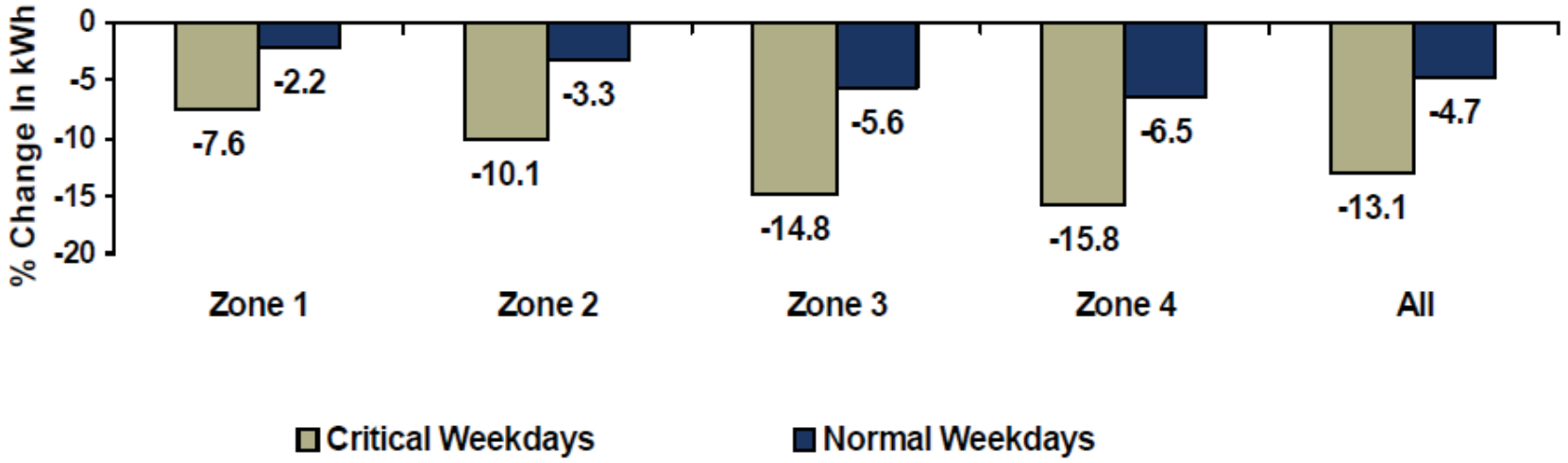
October 15, 2019

Discussion Topics

- Historical overview of 2003 – 2005 Statewide Pricing Pilot (SPP).
  - Residential Critical Peak Pricing (CPP).
  - Small, Medium, and Large Commercial and Industrial (C&I) CPP.
- Overview of 2018 CPP results:
  - Residential.
  - Small, Medium, and Large C&I.
- SDG&E's HourX Residential Time-of-Use Pilot.
- Overview of SDG&Es Petition for Modification of CPP for small business customers.

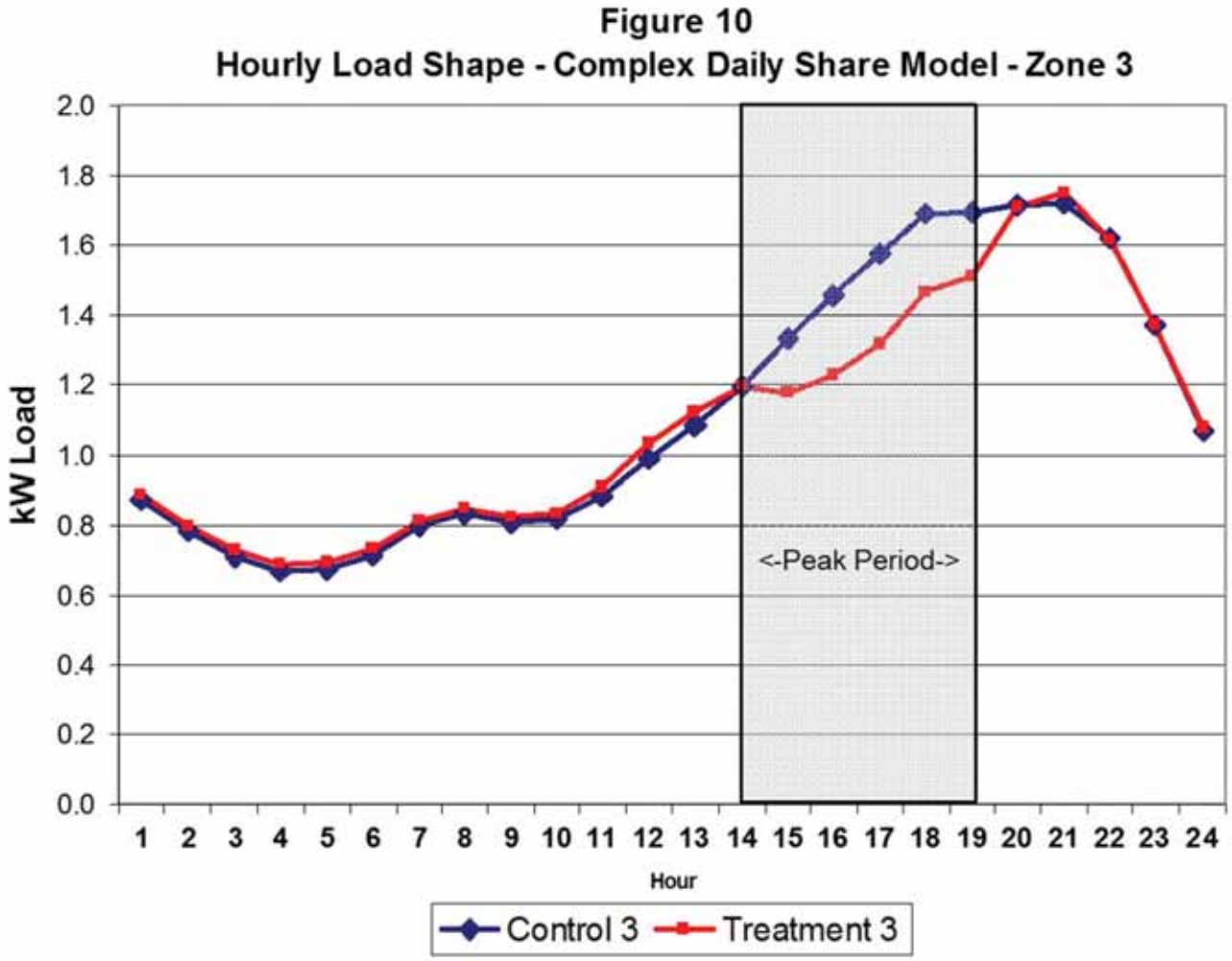
2003 – 2005 Statewide Pricing Pilot
Results For Residential Customers

Percent Change In Residential Peak-Period Energy Use
(Avg CPP-F Prices/Avg 2003/2004 Weather)



CPP-F has a fixed CPP time period from 2pm - 7pm.
Impact Evaluation of the California Statewide Pricing Pilot, CRA, March 16, 2005

2003 – 2005 Statewide Pricing Pilot
Residential Hourly Load Impacts 2003 & 2004 CPP-F



CPP-F has a fixed CPP time period from 2pm - 7pm.
Residential Hourly Load Response to Critical Peak Pricing in the Statewide Pricing Pilot, CRAI, 5/18/2006.

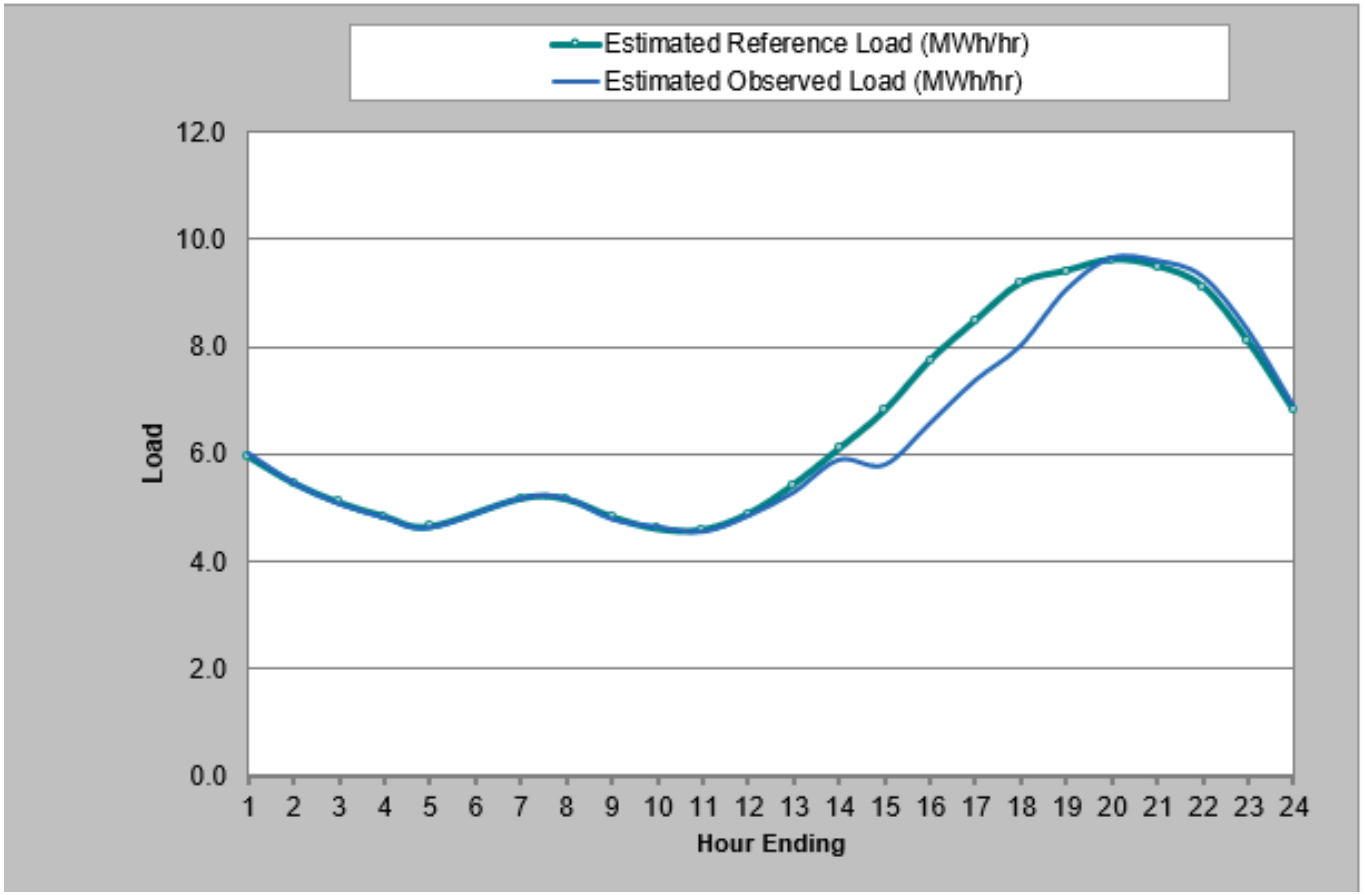
2003 – 2005 Statewide Pricing Pilot Lessons Learned

- There is statistically significant variation in hourly impacts within pricing periods.
- Peak period impacts reach their maximum at 5 pm in all climate zones.
- There is variation in the size of the impacts across climate zones (warmer climates have larger impacts).
- However, the aggregate impacts at the period level did not differ appreciably from the impacts in the March 16th Impact Evaluation report.
- A similar approach can be used to assess hourly impacts for the CPP-V rate, both for residential and small C&I customers.
- Changes since early 2000s in technology, customer behavior, and change in TOU periods may result is different lessons learned today.

Residential Hourly Load Response to Critical Peak Pricing in the Statewide Pricing Pilot, CRAI, 5/18/2006.

Overview of CPP 2018 Ex Post Load Impacts for Residential Customers (6,796 Customers Evaluated)

Load Impact Type:	CPP Load Impact for CPP Customers Excluding TD
Type of Results:	Aggregate Impact
Day Type:	September System Peak Day
Climate Zone:	All
Forecast Year:	2018
Weather Year:	Utility 1-in-2
Impact Level:	Portfolio-level impacts



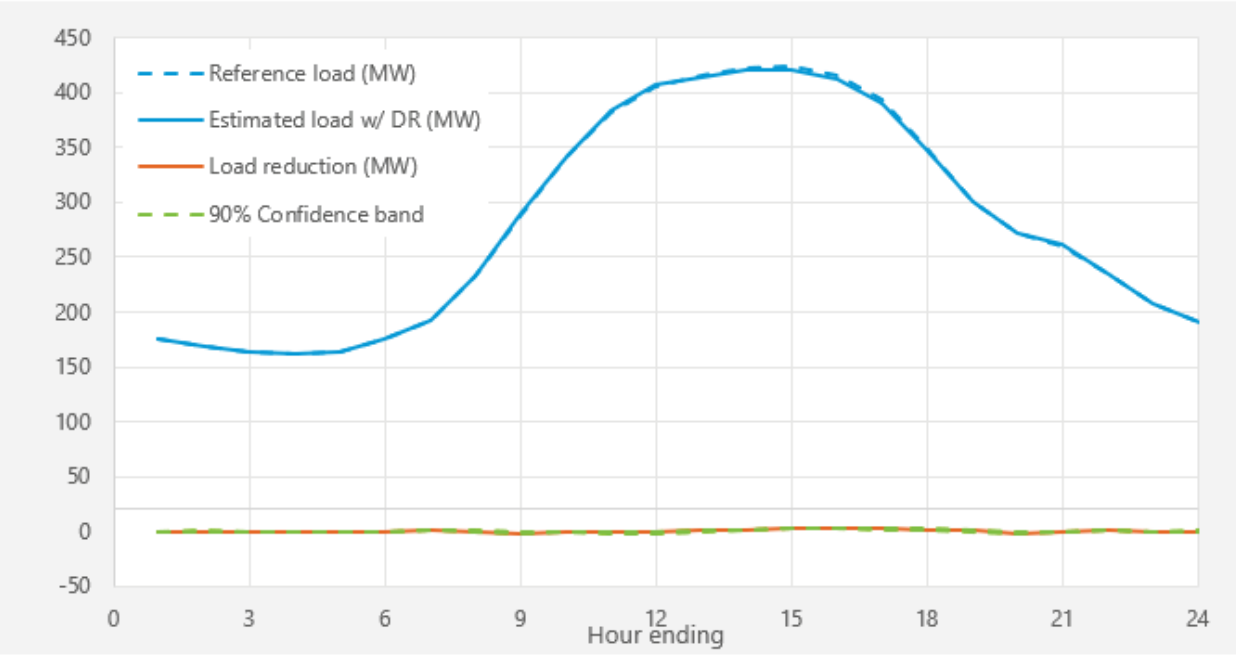
Source: 2018 Load Impact Evaluation of SDG&E's Voluntary Residential Critical Peak Pricing (CPP) and Time-of-Use (TOU) Rates, CAE, April 1, 2019.

Overview of 2018 Ex Post CPP Results For Small C&I Average Weekday Event

Type of results	Aggregate
Category	Portfolio impacts
Subcategory	Portfolio (excludes dual enrolled)
Event date	Avg. Weekday Event 2018

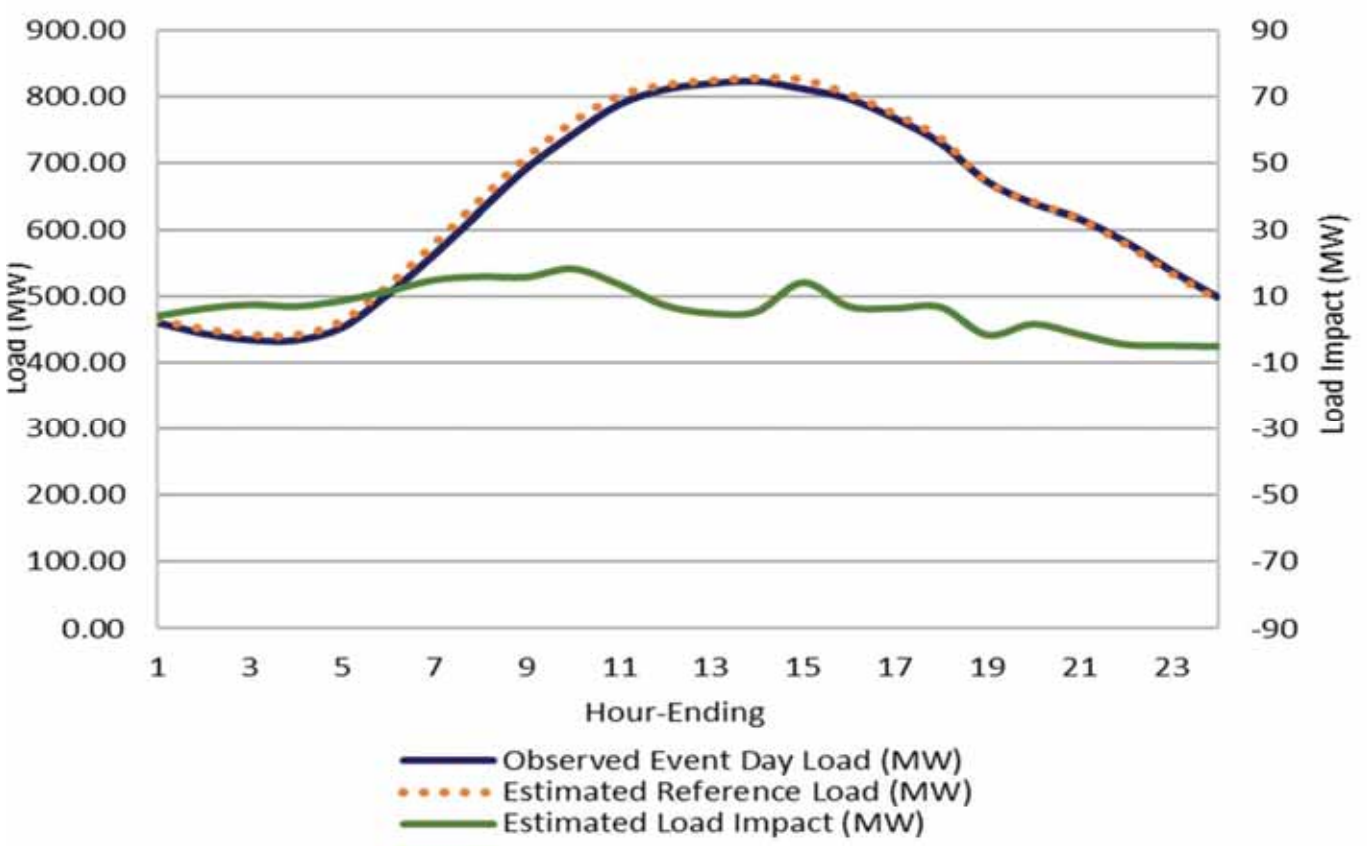
Table 2: Event day information

CPP Event start	2:00 PM
CPP Event end	6:00 PM
Total enrolled accounts	111,149
Avg load reduction 11AM-6PM	1.80
% Load reduction 11AM-6PM	0.4%
Avg load reduction 2PM-6PM	2.72
% Load reduction 2PM-6PM	0.7%



Source: SDG&E Small Commercial Time Varying Pricing and Technology Deployment Evaluation for Program Year 2018, DSA, April 1, 2019.

Overview of 2018 CPP Results for Medium and Large C&I
Ex Post M&L Load Impacts - Average Summer Event, Average Event Hour



- Large customers provide the majority of the impact.
- Small customers are not included in this evaluation.
- Coolest weather of the three IOUs.

Utility	Size Group	# Enrolled	Ref. Load (MW)	Load Impact (MW)	% Load Impact	Event Temp
SDG&E	Large	1,211	348.1	6.9	2.0%	88.5
	Medium	12,854	437.5	1.9	0.4%	88.2
ALL SDG&E		14,065	785.6	8.8	1.1%	88.3

Source: 2018 Statewide Load Impact Evaluation of California Non-Residential Critical Peak Pricing Programs Ex-Post and Ex-Ante Load Impacts, AEG April 1, 2019.

SDG&E's HourX Residential Opt-In Time-Of-Use Pilot
SDG&E Load Analysis

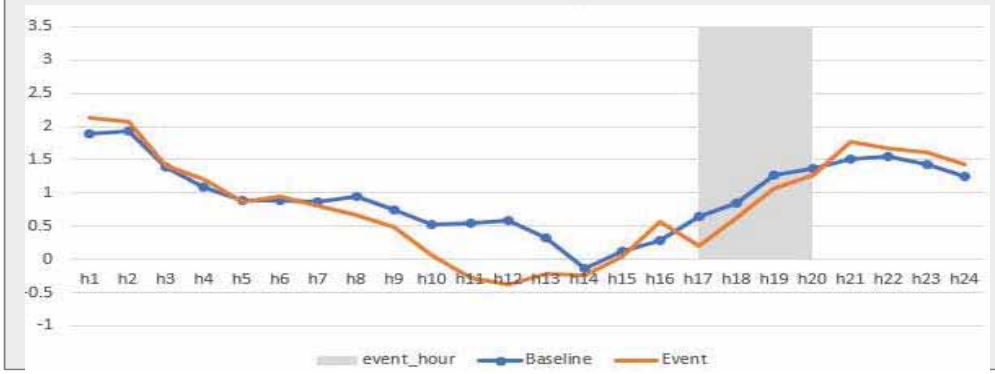
37 System Events 2017

- Apply to the entire system - adder is higher
- Benchmark is calling 150 events per year
- May or may not coincide with any circuit events

186 Circuit Events 2017

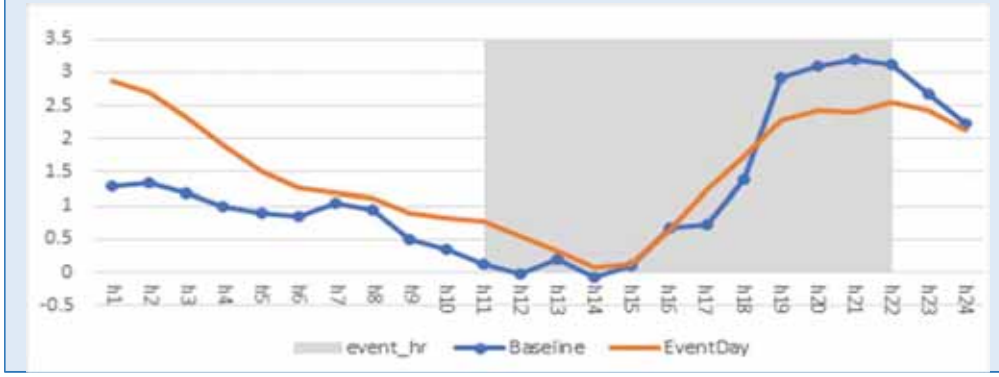
- Circuits are local or customer specific- adder is lower
- Benchmark is calling 200 events per year
- Events are based on the equipment necessary to bring power from the substation to the customer

Example A



- Relatively short event duration (3 hours, between 5pm-8pm) enables customer to prepare and recover
- Distinct load reduction prior to event (hour 17)
- "Recovery" period after event occurs

Example B



- Day of system peak (4,544 MW at 4pm on 09/01/17)
- Long event duration (11 hours, between 11am and 10pm), making it more difficult to reduce/shift load
- Customer managed to reduce relative to baseline

SDG&E's HourX System Events

5 system events (June & July 2017).

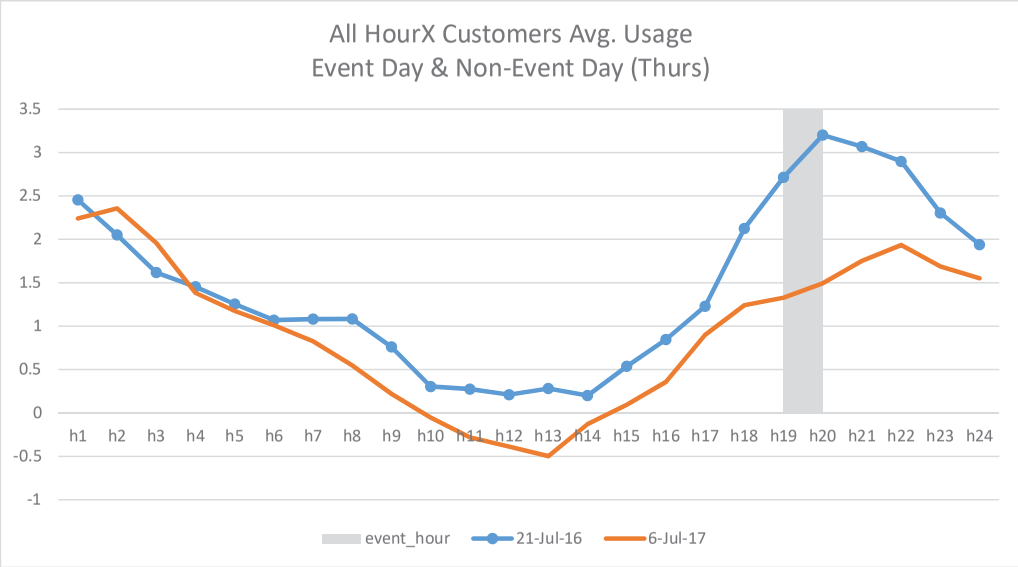
- June 19, 20 & 21.
- July 6 & 7 (Shown in Graphs).

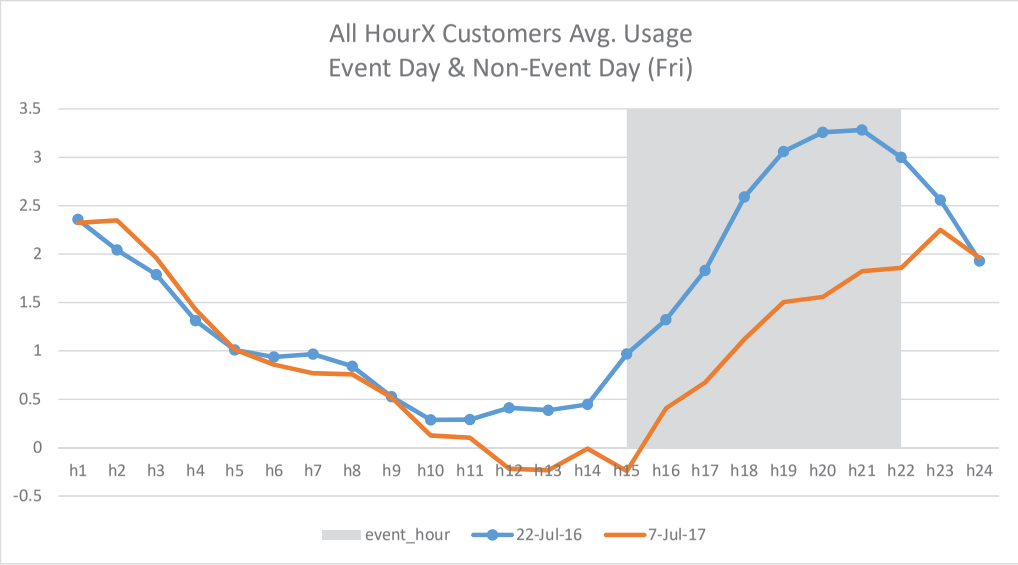
Orange – event day.

Blue – baseline day (Baseline selected on similar weather pattern and day-of-week).

X-axis – Hour of Day.

Y-axis – kw.





Source: SDG&E Load Analysis.

Critical Peak Pricing (CPP) Petition for Modification – Small Commercial Customers

Background

- SDG&E seeks to place new small business customers on a TOU-only rate, and they can elect to participate in the TOU-CPP if they choose. Existing customers would be unaffected.
- SDG&E found the current approach of applying CPP as the "default rate" for small non-residential customers has led to increased bill volatility, a corresponding increase in customer complaints, and a relatively insignificant reduction in load.
- CPP rates are current default rates for Small Commercial, M/L C&I, and Agricultural customers.
- CPP is a dynamic rate intended to motivate customers to reduce their electricity use during periods of high system demand using price signals. In return for reducing their load during "event days," these customers receive lower rates throughout the remainder of the year.

Increased Bill Volatility

Expected monthly bill increases on CPP event days when usage is not reduced[5]

Events per month	1 event	5 events	9 events
Monthly % Bill Increase	5%	26%	47%

[5] On average, during an CPP event period, the price of electricity increases by over 320%. The total rate in summer on-peak goes from 36.6 cents per kWh to 153.6 cents per kWh.

Critical Peak Pricing Petition for Modification – Small Commercial Customers

Increase in High Bill Calls as More Events are Called

	2016			2017			2018		
	July	Aug	Sep	July	Aug	Sep	July	Aug	Sep
Number of CPP events called	0	0	1	0	1	2	3	3	0
Number of high bill complaints	56	97	62	86	93	338	355	616	280

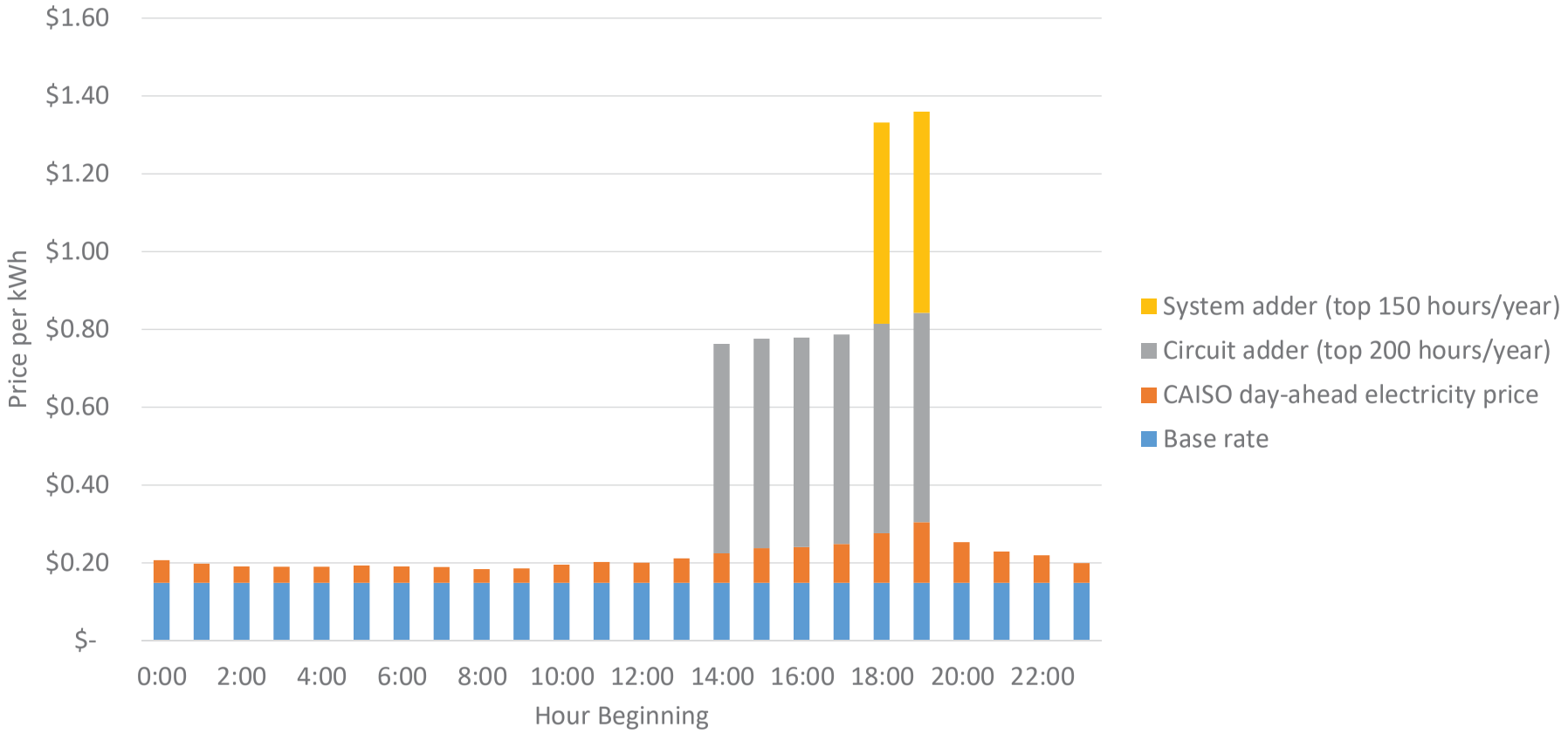
Limited Load Reduction Achieved

- The isolated CPP portion of the rate provides less than 1% of MW load reductions during event days relative to available total load. This equates to .02 KW per customer per year, or 2.7 MW annual load reduction).
- The isolated TOU rate structure within SDG&E's TOU/CPP rate provided a 2.6% or approximately 7 MW aggregate load reduction.

Conclusions

- Customers' ability to reduce usage when critical peak pricing event days is important to their success on an event-based dynamic rate.
- Many small non-residential customers do not have the operational flexibility to reduce their energy use during critical peak pricing events while continuing to meet the basic energy needs required to operate their business.
- Customers who knowingly choose an event-based dynamic rate are more likely to respond by reducing their energy use.
- Structural winning on a dynamic rate means that customers may benefit annually on a dynamic rate even if they are unable to reduce electricity usage during a critical peak pricing event.
- It is reasonable to establish a time-variant rate (without an event-based critical peak pricing feature) as the standard rate option for small non-residential customers initiating SDG&E service.

VGI Rate (Power Your Drive)



- The VGI rate used in the Power Your Drive (PYD) program changes to reflect real-time grid conditions. Customers can “set and forget” the maximum price they wish to pay using the smartphone app.

ATTACHMENT D

REAL TIME PRICING AND TRANSACTIVE ENERGY

Real Time Pricing and Transactive Energy Rates

Reuben Behlihomji

Senior Manager – Modeling, Forecasting & Economic Analysis

SOUTHERN CALIFORNIA EDISON®

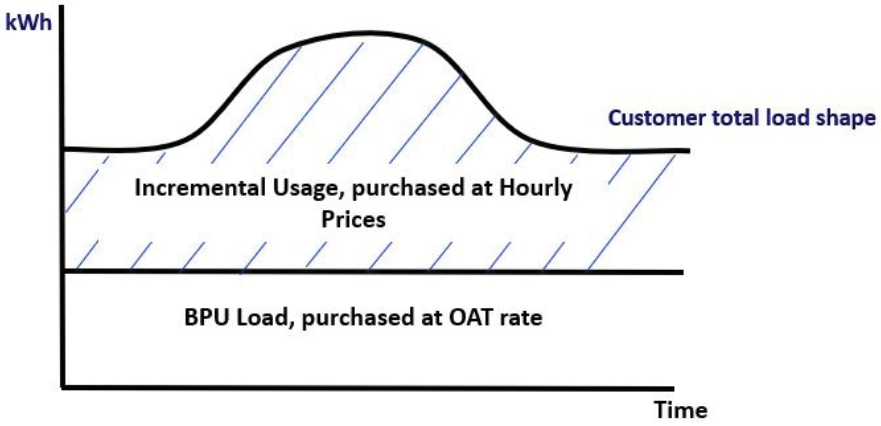
Two-Part Real Time Pricing (RTP)

SOUTHERN CALIFORNIA EDISON®

Two-Part RTP | Concept

- Current RTP is template based where hourly prices are reflected in 7-day type pricing menus
  - Temperature trigger
  - Peak and ramp capacity allocated to day types based on expected capacity need
  - Energy profiles reflect SCE's marginal generation energy cost profile
- Under a generation only 2-part RTP structure, usage (energy and demand) associated with generation charges is partitioned into a base amount and a RTP amount
  - Delivery portion of the bill is considered to be entirely base usage
- Base usage or Base Period Usage (BPU) is predetermined based on historical usage over a set period of time (i.e., prior 12-months, 3-year average, etc.)
  - Likely to be seasonal and reflect the prevailing TOU periods
  - BPU structure is currently used in SCE's Schedule ME at the Port of Long Beach
- Bill is rendered by charging OAT generation rates for all BPU kWh and kW
  - Delivery portion is rendered by applying metered kWh and kW to the OAT delivery charges
- Metered hourly kWh and kW above the baseline will be charged (or credited) at an Hourly Price

Two-Part RTP | Proposal (Illustrative)



$$\text{RTP Bill} = \text{OAT Bill @ BPU Load} + \sum_{\text{all hrs}} \left\{ \left(\text{Actual Load} - \text{BPU Load} \right)_{\text{per hr}} \times \text{Hourly Price} \right\}$$

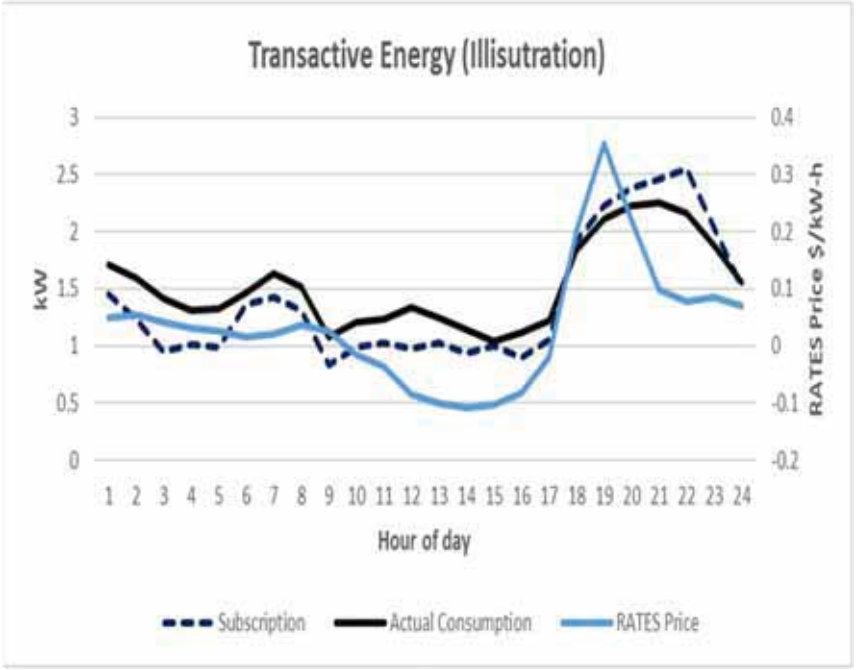
$$\text{Hourly Price} = \text{Adj. DLAP Price}_{\text{per hour}} + \text{Gen Capacity Adder}_{\text{per hour}}$$

Two-Part RTP | Hourly Price Determination

- Two-Part RTP Hourly Prices is comprised of generation energy and capacity
  - Capacity component reflects both peak and flex capacity costs
- Hourly Capacity Adder will be triggered and valued based on an Implied Market Heat Rate (IMHR)
  - IMHR = CAISO DLAP Price / SoCal Citygate Day Ahead Natural Gas Price
  - Hourly Capacity Adder will be applied as an overlay to hourly energy prices in the 4-9pm period year round
  - Daily IMHR determinants reflect the availability of peak and flex generation capacity
- Hourly Energy Prices will use the actual CAISO Day Ahead Energy Market Price for SP15
- A scaler will be applied to ensure revenue neutrality for the Two-Part RTP rate
  - Applied to the hourly energy prices or capacity prices, or both
  - Recovered as a flat adder in the BPU bill
  - Combination of all of the above

Retail Automated Transactive Energy System (RATES)

RATES | Concept



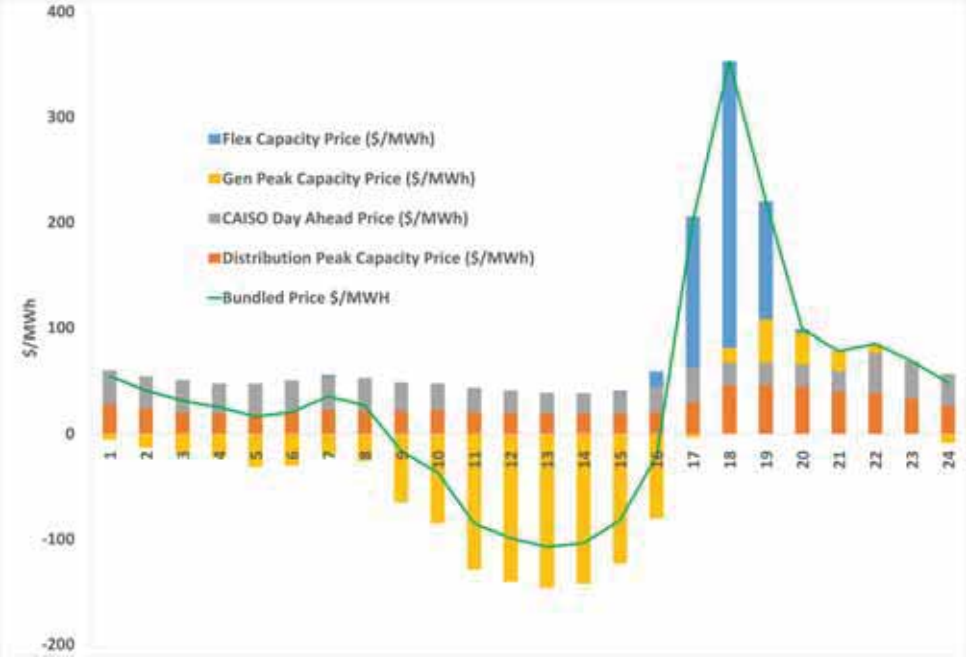
- Subscribe at specific costs and quantity for each hourly interval
  - Monthly Fixed Subscription Cost is calculated using the Customer's SCE Tariff.
  - The subscription is a forward contract at fixed monthly cost that stabilizes bills (cost to customer and revenue to suppliers).
- RATES can automatically buy and sell at the same tender prices in each interval while maintaining customer comfort, etc.
- Scarcity pricing used to recover more fixed (long-run marginal) cost when the delivery (in either direction) or generation system is more heavily loaded
- Addresses
  - Bill and revenue volatility
  - Grid stability
  - Recovery of both fixed and variable costs for all parties with settlement calculations
  - Forward transactions support better operational planning

RATES | Price Components

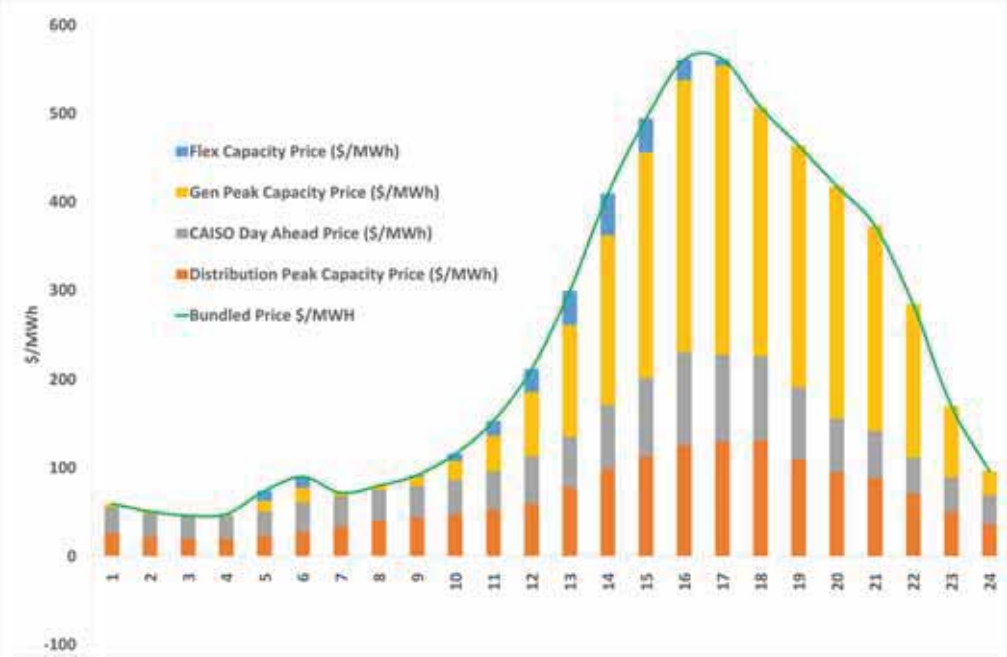
- CAISO Locational Marginal Price @ Transmission Interface
- Generation Fixed Cost (Long-Run Marginal Cost) Recovery
  - Energy Fixed Cost
  - Flex Fixed Cost
- Circuit Delivery Losses and Fixed Cost Recovery (Long-Run Marginal Cost) from Transmission Interface to Facility (can be facility specific)
- Fixed costs such as metering, billing, public purpose included in subscription costs

RATES | Transactive Hourly Prices

Typical Winter Day



Typical Summer Day



ATTACHMENT E

DYNAMIC PRICING IN OTHER JURISDICTIONS

RTP and Dynamic Rates in Other Jurisdictions

CPUC Workshop on Dynamic and Real-Time Pricing

Scott Murtishaw
Senior Advisor
October 15, 2019

CALIFORNIA SOLAR + STORAGE ASSOCIATION
smart local energy

RTP in Illinois

- RTP available to all ComEd and Ameren customers
- 42,000 res and small C&I customers enrolled
- ComEd bills assessed based on hourly average of 5-minute market prices; Ameren uses day-ahead hourly prices
- ComEd customers can also sign up for AC cycling or automation through IFTTT platform
- Day-ahead and day of (ComEd) alerts can be sent by phone, text, or email; prices also available via app

C&I RTP in Georgia

- Day ahead pricing available for C&I customers ≥ 250 kW
- Hour ahead pricing for customers ≥ 5 MW
- Approximately 2,300 participants representing 20% of retail revenues
- Customers may reduce exposure by contracting for fixed prices for historic load shape

SmartHours-VPP in OK and AR

- Smart Hours program from OG&E for res and small C&I customers has set weekday peak period (2pm – 7pm)
- Peak periods prices set day-ahead at one of four levels ranging from 5 to 41 cents
- Alerts sent by phone, text or email
- Participants can also automate response with SmartTemp thermostats
- Approx 20% residential enrollment, saving avg of $150 per year

SmartHours Res Load Reductions

	High Price	Critical Price
VPP+ (w/ SmartTemp)	0.77 kW	1.41 kW
VPP rates only	0.06 kW	0.37 kW

Other examples

- Large C&I on mandatory RTP in New York since 2006
- RTP became in the default rate for residential customers in Spain in 2014, approximately 40% currently enrolled
- Griddy Energy and other companies give customers direct access to the wholesale market for a monthly fee

ATTACHMENT F

RTP RATE PROPOSALS FOR SDG&E GRC

RTP Rate Proposals for SDG&E GRC

Scott Murtishaw
Senior Advisor
October 15, 2019

CALIFORNIA SOLAR + STORAGE ASSOCIATION
smart local energy

RTP Option for All

- SDG&E should offer two RTP options: Day-Ahead and Five-Minute
- Both tariffs should be available to all customers, but could focus Day-Ahead on smaller customers
- Day-Ahead provides more time to plan response whereas five-minute more accurately reflects day-of conditions
- Other options could include pricing based on hour-ahead or fifteen minute markets

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Structure of Day Ahead RTP

- Similar to SDG&E's Grid Integration Rate
- Day-ahead prices passed through to customer
- Most generation capacity costs recovered through top 150 hour surcharge
- No generation-related demand charge

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Structure of Day Ahead RTP (2)

- 50% of distribution revenue recovered through top 200 hour circuit surcharge
- No distribution demand charge
- User pays fixed charges, NBCs, FERC transmission at otherwise applicable tariff
- A commodity base rate covers costs such as RPS and above-market legacy procurement costs

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Structure of 5-Minute RTP

- Five-Minute market prices passed through to customer using average price across the billing interval
- Other elements same as day-ahead rate
- Participants can receive day-ahead and day-of pricing alerts

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Hedging Option

- SDG&E should offer RTP customers the chance to hedge their exposure by buying blocks of energy at the standard TOU generation rate
- For residential and small C&I customers options could be simplified to offer a small number of basic load shapes scaled to annual usage

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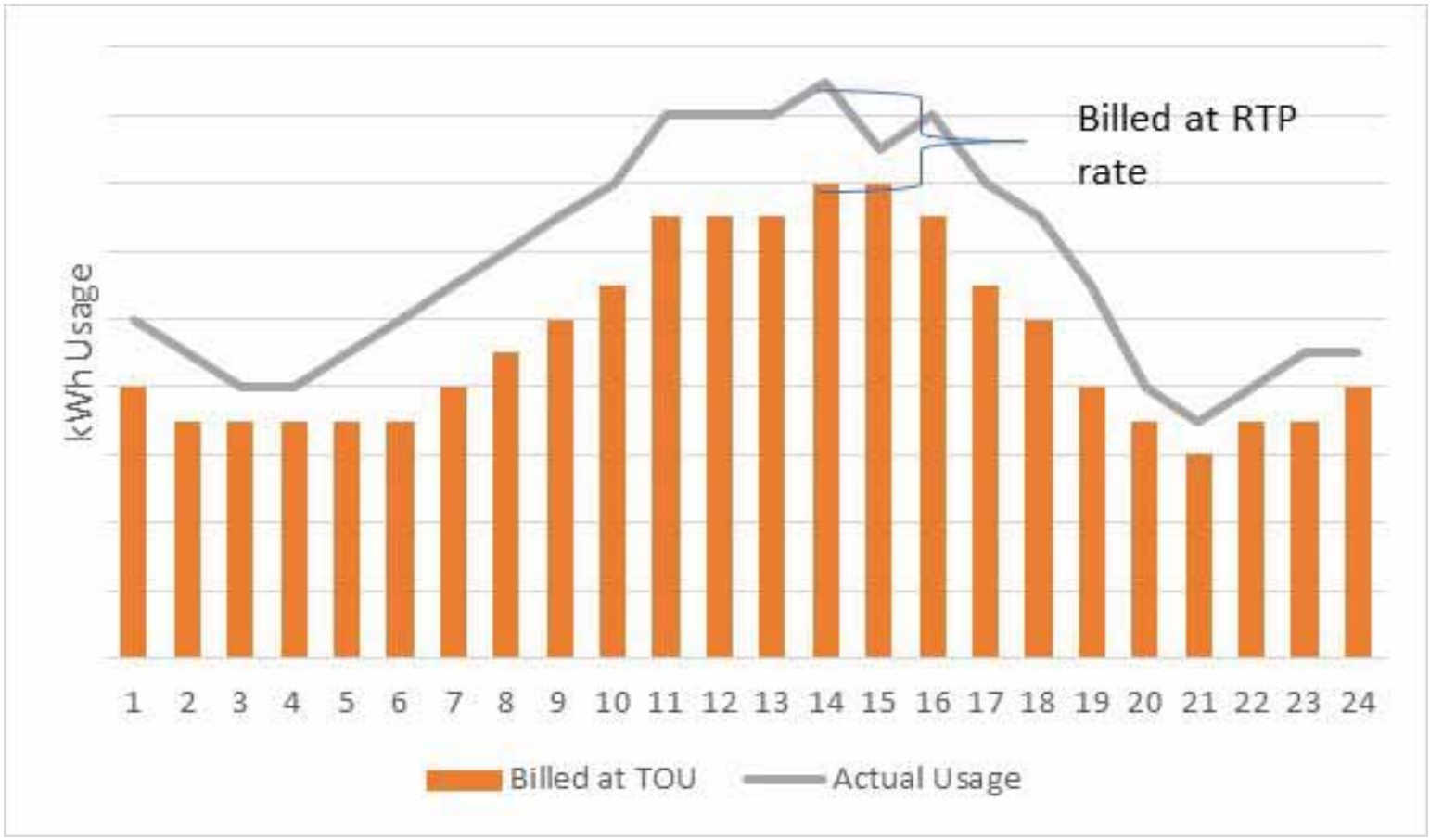
Example of Hedging Product



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Enabling Customer Response

- Day-ahead prices and high-price alerts should be distributed by email, text, phone, and app
- Push prices to devices whether day-ahead or five-minute
- SDG&E should facilitate automation by partnering with vendors who offer AC, energy storage, EV, and smart appliance load management products and services

RTP in Context of LSWG

- Our RTP proposal scores well on LSWG metrics:
  - Dispatch method since prices directly informed by wholesale market
  - Locational granularity with circuit-specific adders and, where applicable, sub-LAP pricing
  - Temporal granularity, especially five-minute option
- Incentivizes bi-directional load response
- Non-integration into CAISO market reduces complexity, reduces expense, and avoids need for counterfactual baselines

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ATTACHMENT G

CHALLENGES OF DYNAMIC AND REAL TIME PRICING

PUBLIC ADVOCATES OFFICE

Dynamic and Real Time Pricing

San Diego Gas & Electric GRC Phase 2

A.19-03-002

October 15, 2019 Workshop

Any New Rate Designs Should Be Pilot Tested

- Too little is known about the billing determinants of customers who will participate in these programs.
  - Using the general class billing determinants to design dynamic rates or RTP may lead to cost shifts that are not cost-based.
- RTP has the added problem that it is difficult to know how large a markup to apply to day-of RTPs in rate design for generation capacity costs and EPMC.
  - The combined markup (74% for SDG&E) could be recovered in a TOU volumetric rate, but the latter would have almost as much influence on the bill as the RTP component.
  - Recovering the authorized generation revenue requirement in an hourly RTP that cannot be known in advance is problematic, even with a TOU volumetric rate for the markup.

Unintended Consequences

- Conducting a pilot would avoid any unintended consequences, such as increased GHG emissions.
  - The latter could be avoided by requiring that energy management systems integrate a GHG signal into their dispatch algorithms.
  - D.19-08-001 requires future SGIP programs to use a GHG signal to reduce GHG emissions by five kg/kWh or be subject to incentive payment reductions.
  - WattTime provides such a signal.
- With programs in the Load Shift Working Group Report, incentives paid inadvertently could duplicate bill reductions customers receive from load shifting if both are based on the same marginal costs.
  - A concern is rate riders (e.g., DLS and MINTDS) added to NEM tariffs.
  - If the intent is for solar customers to install storage, such behavior could be incentivized by merely reducing the solar export compensation rate below the retail rate.
- Other unintended consequences include unexpected revenue shifts and low participation.

The Pilot Should Provide Information on Any Expected Revenue shortfall

- Participants should not be allowed to keep the benefits from revenue shortfalls that exceed grid benefits.
- Rates may have to be adjusted over time to reduce revenue shortfalls that are not cost based.
- The sample size in the pilot should be large enough to adequately assess the magnitude and type of revenue shortfall.

The Pilot Should Estimate the Ultimate Level of Participation

- Rates that change every 5 or 15 minutes to reflect grid needs, and which become negative during renewable curtailment, provide the greatest benefits to the grid.
  - But such rates may be difficult to predict in advance.
  - This may make it challenging for customers to determine whether the benefits of such rates would cover the cost of new technologies they might install.
  - The RTP price signal may be small compared to an accompanying TOU rate to recover the generation markup and the distribution rates.
- It also is unclear how many customers have sufficient operational flexibility to accommodate RTPs or even CPP.
- The study should assess what kind of education and outreach will be required once the rate progresses beyond the pilot phase.

Information that the Pilot Studies Should Collect

- The pilot tests should collect information on revenue shortfalls that are not cost-based, typical load profiles of participants, demand responses, technologies employed, and decreases (or increases) in GHG emissions.
  - The influence of non-coincident demand charges on GHG emissions and use of storage should be evaluated.
- The pilot should determine what level of granularity in the rate is possible given the utility customer billing system constraints.
- The pilot also should assess what load diversity benefits exist that can be used to reduce the rate.

The Pilot Should Evaluate Diversity Benefits

- Past demand charge discounts to solar and plug-in electric vehicle customers have been justified based on their loads being non-coincident with the rest of the class.
  - These discounts should not be permanent because, as such loads increase as a total percentage of class load, the diversity benefit decreases (e.g., solar and "duck curve" issues").
- No demand charges exists for residential and small commercial customers partly because of the load diversity within those classes.
  - But it is unclear at what customer size level these diversity benefits decrease sufficiently to justify demand charges.
  - The pilot study should investigate this.
  - In the interim, it is important that the class revenue requirements reduction, caused using Effective Demand Factors (EDFs) in revenue allocation, flow entirely to non-coincident demand charges in rate design (see example on next page).

Diversity Benefits

- Very large customers on dedicated feeders or circuits have almost no diversity at the distribution level.
  - Thus distribution non-coincident demand charges may remain relevant to them.
  - Though some diversity may exist at the substations, SDG&E's substations marginal costs are small ($19.61/kW-yr.) compared with the circuit marginal costs ($52.05/kW/yr.).
- Diversity benefit example:
  - Assume a class with only a school and church with equal non-coincident loads.
  - One peaks on weekdays and the other on weekends.
  - In this example, the EDF = 0.50.
  - The EDF, in this example, would be used to reduce the marginal distribution demand costs applied in revenue allocation by 50%.
  - In rate design, this discount should flow entirely to the non-coincident demand charges.

SDG&E's Distribution System Effective Demand Factors

Customer Class	Circuits	Substations
Residential	34.90%	31.95%
Small Commercial	47.24%	43.41%
Medium/Large Commercial & Industrial	73.37%	68.21%

- SDG&E's demand charges could more accurately reflect EDFs if the Medium/Large Commercial and Industrial class were split into two, as PG&E and SCE have done.

ATTACHMENT H

CRITICAL CONSUMPTION PERIOD PROPOSAL

Critical Consumption Period

Paul Nelson
For California Large Energy Consumers Association

Real Time Pricing Workshop
October 15, 2019

Large amounts of Solar PV is being built as a result of CA Energy Policies: Zero Net Energy, Net Energy Metering, and Renewable Requirements

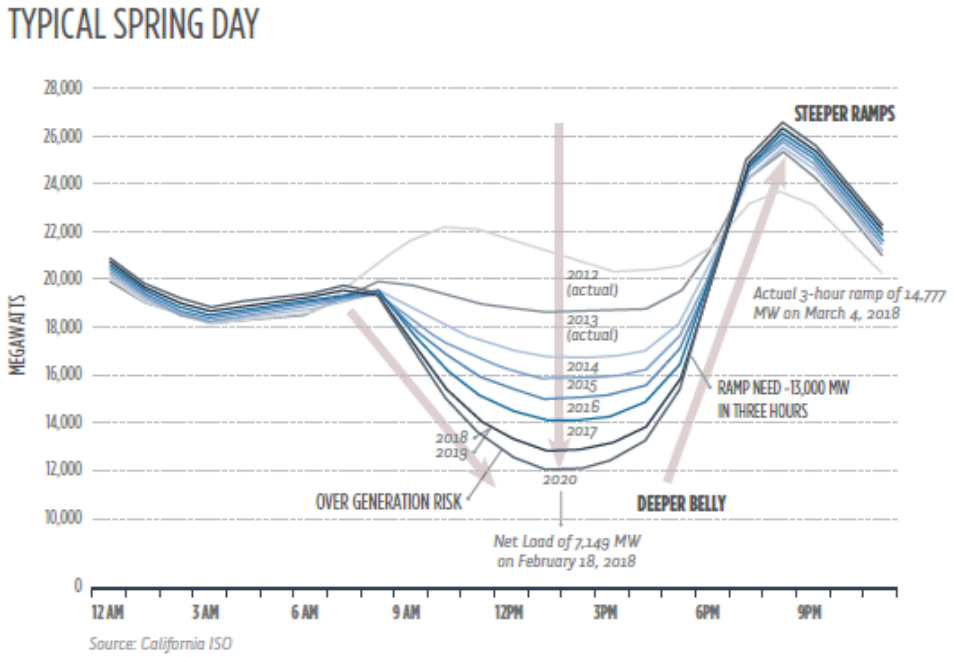
Excess generation occurs during the spring, and often results in curtailment of clean power, or it is exported to other states

The Critical Consumption Period would encourage customers to utilize this excess power which avoids curtailment and keeps low-cost power in CA

During the belly of the duck, CAISO prices will be very low or negative

- Increased energy use in the mid-day will trim the belly of the duck which reduces over generation and reduces the need for ramping

A trim duck is a healthy duck! Don't think about extending duck hunting season to spring



Critical Consumption Period

- Load serving entity would trigger the Critical Consumption Period based upon negative CAISO day-ahead prices
- Generation price would reflect impact of CAISO real-time prices
  - Non-generation charges remain in place
- Would dispatch at CAISO p-node location based upon its price
  - This would avoid encouraging increasing usage in Transmission constrained areas
- Would use either 15- or 5-minute pricing
- Performance measured using a baseline (i.e. 10/10)
- Low prices are correlated with excess clean energy, so no increase in GHG
  - If load is shifted from other periods, there could be attributable GHG reductions

Transmission and Distribution (T&D) charges are an implementation challenge

- An increase in monthly non-coincident peak transmission (FERC) demand charge could overwhelm the energy benefit from periodic Critical Consumption Periods
- Solution is to neutralize the impact of any increased demand during the event period. Some ideas:
  - Exclude demand measurement during event hours in determining the monthly peak demand charges
  - Perhaps a credit or incentive payment to off-set any impact of the non-coincident peak demand charges based upon the customer's performance
- Complete elimination of demand charges is not proposed as this could encourage usage during the wrong periods which could lead to cost increases
- IOUs should monitor program impacts on T&D system to detect any adverse impacts and adjust future rate design

Benefits of Critical Consumption Period

- Customer responds to real-time price signals
- Avoids curtailment of renewable energy; CA customers are already paying for its renewable attribute
- Provide improved grid reliability and reduces the need for ramping capacity
- Lower energy prices benefits CA consumers
- Keeps production of energy intensive products made in CA which prevents leakage of GHG emissions

ATTACHMENT I

MIDAS: EMISSION FOCUSED DEVICE OPTIMIZATION

ENVIRONMENTAL DEMAND RESPONSE

October 2019

WattTime

"Giving people the power to choose cleaner electricity"

Who We Are

- High-tech nonprofit dedicated to accelerating the development & spread of new sustainability techniques
- Built by 200+ volunteers from Google, MIT, Climate Corp, DOE, and more
- Joined forces with Rocky Mountain Institute in 2017

What We Do

- Obsessed with understanding grid emissions at a granular level and building tools to help others use that information to maximize impact and advance goals
- Effectively utilize granular emissions data (5 minute intervals) over 100 U.S. grid regions

MIDAS

Market Informed

Demand Automation

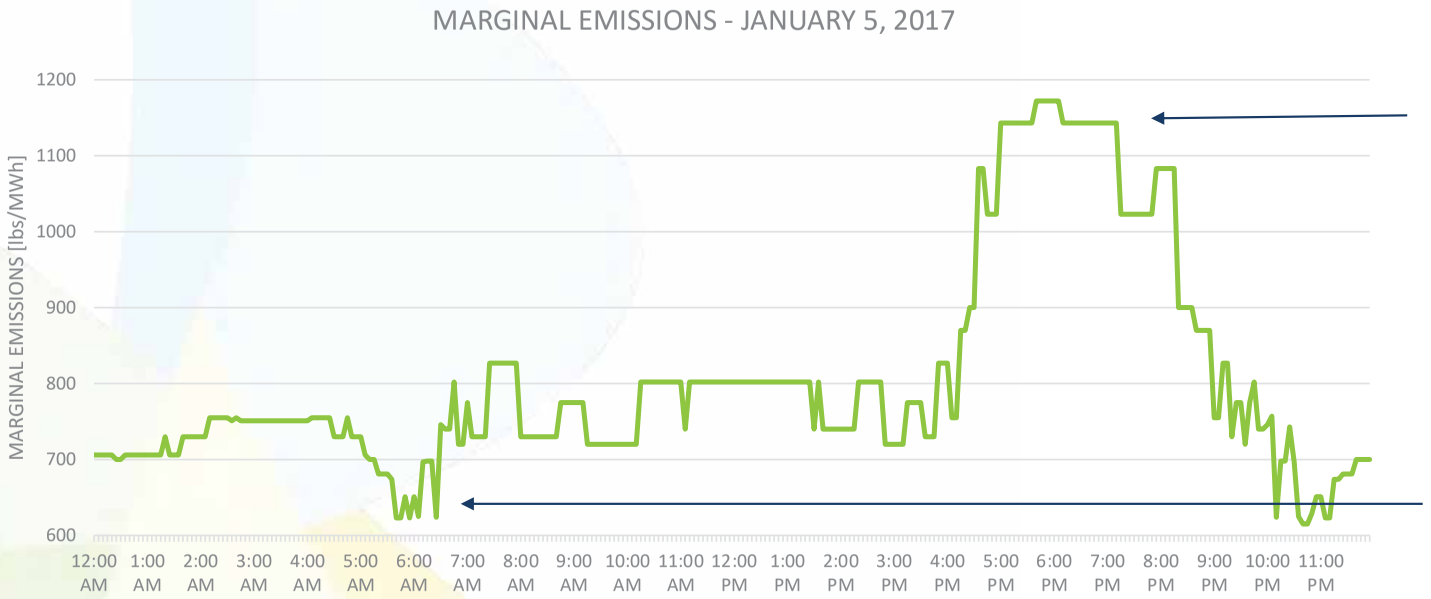
Service

MIDAS

MARKET INFORMED

Grid Emissions Vary By Time

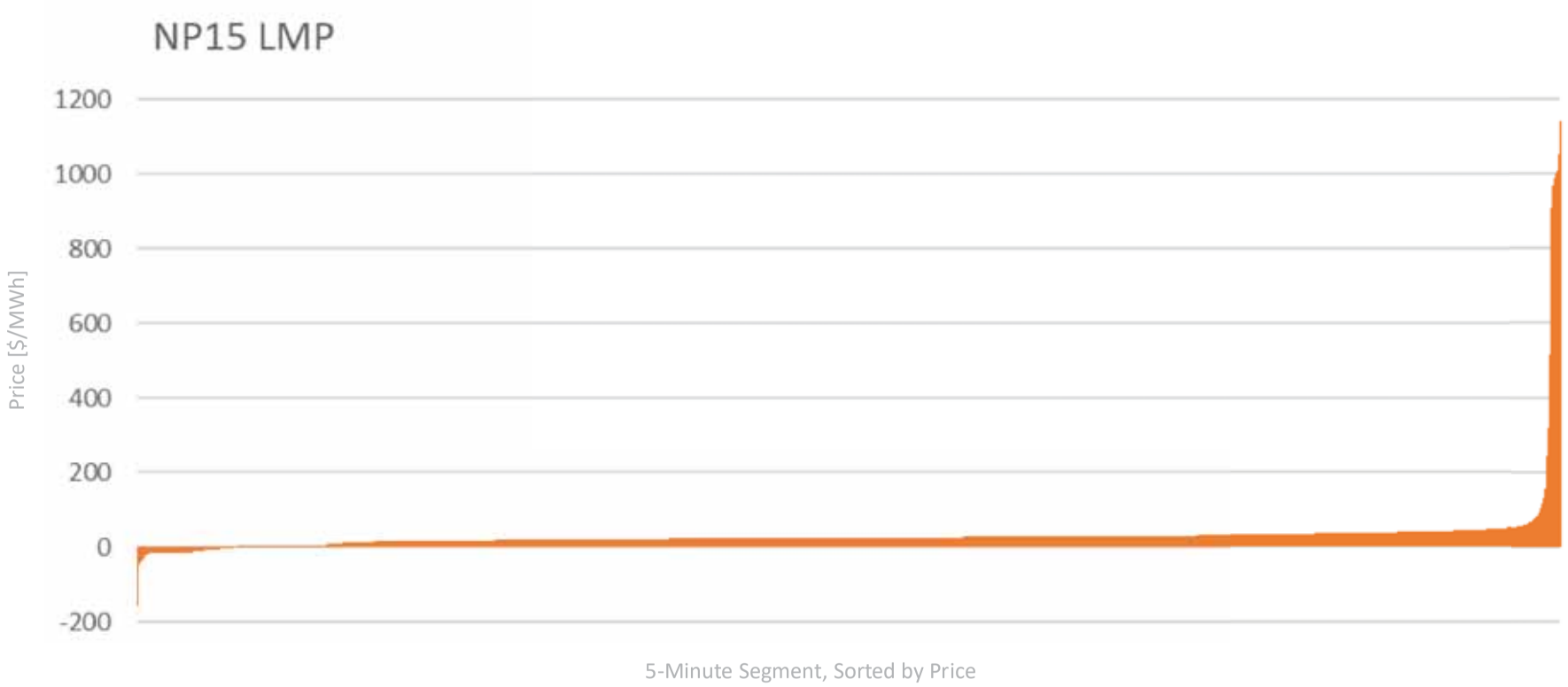
The marginal power plant that reacts when you flip a switch is always changing. Power customers don't know in real time how dirty their power is.



A dirty time on the grid. Using electricity at this time causes more carbon emissions.

A clean time on the grid. Using electricity at this time causes fewer carbon emissions.

LMP Price Frequency



Price of electricity (In dollars per megawatt-hour, Northern California, 2017)

Combining AER & Demand Response

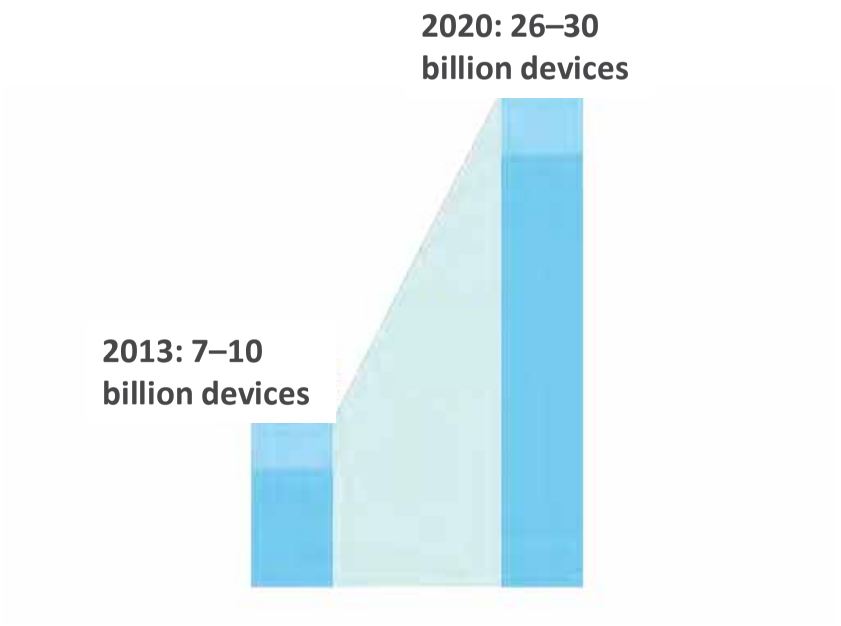
MIDAS
DEMAND AUTOMATION

Customers are increasingly demanding communicating, controllable, and "smart" devices and control systems

Smart devices, appliances, and controls are growing in availability and popularity

- The smart thermostat market is projected to quadruple in size, reaching a $4.4 billion dollar industry by 2025.`
- Large consumer technology companies are now competing for market share in the growing "smart home" space.
- In institutional, commercial, and industrial facilities, business priorities are driving customers to demand connected, intelligent control systems to manage loads.

Some 30 billion devices may be connected to the Internet of Things (IoT) by 2020[2]

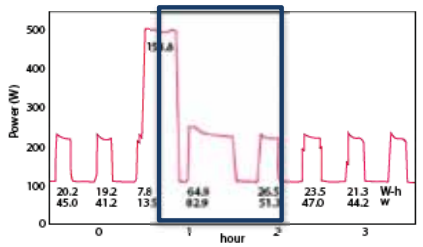


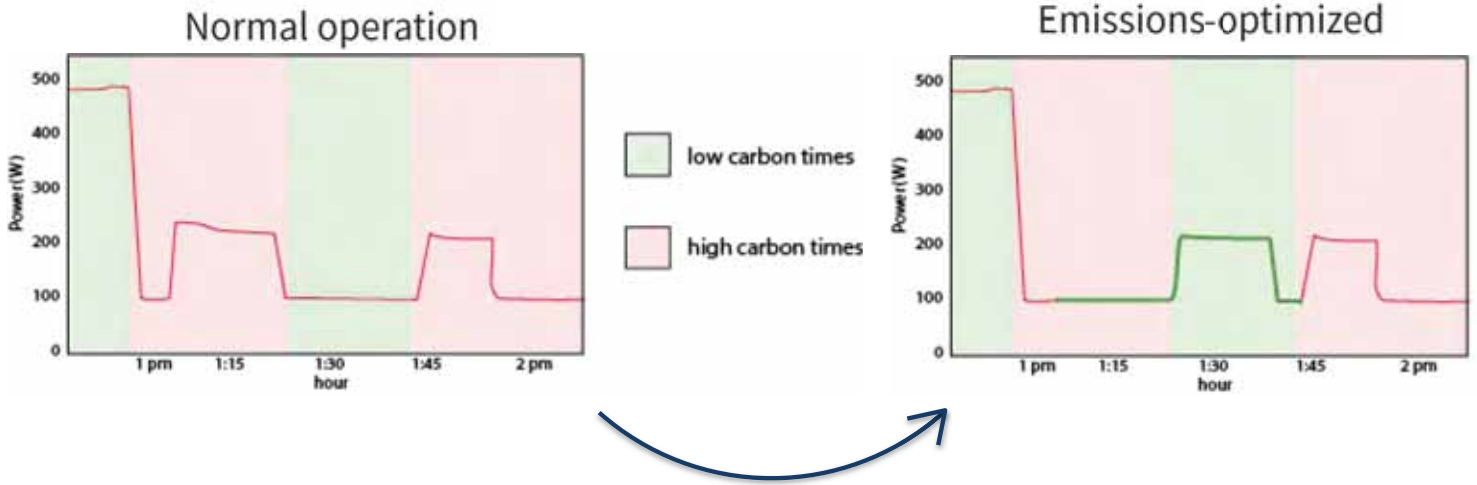
Source: [1] Navigant Consulting; [2] McKinsey, December 2014

Emissions Reductions through Timing

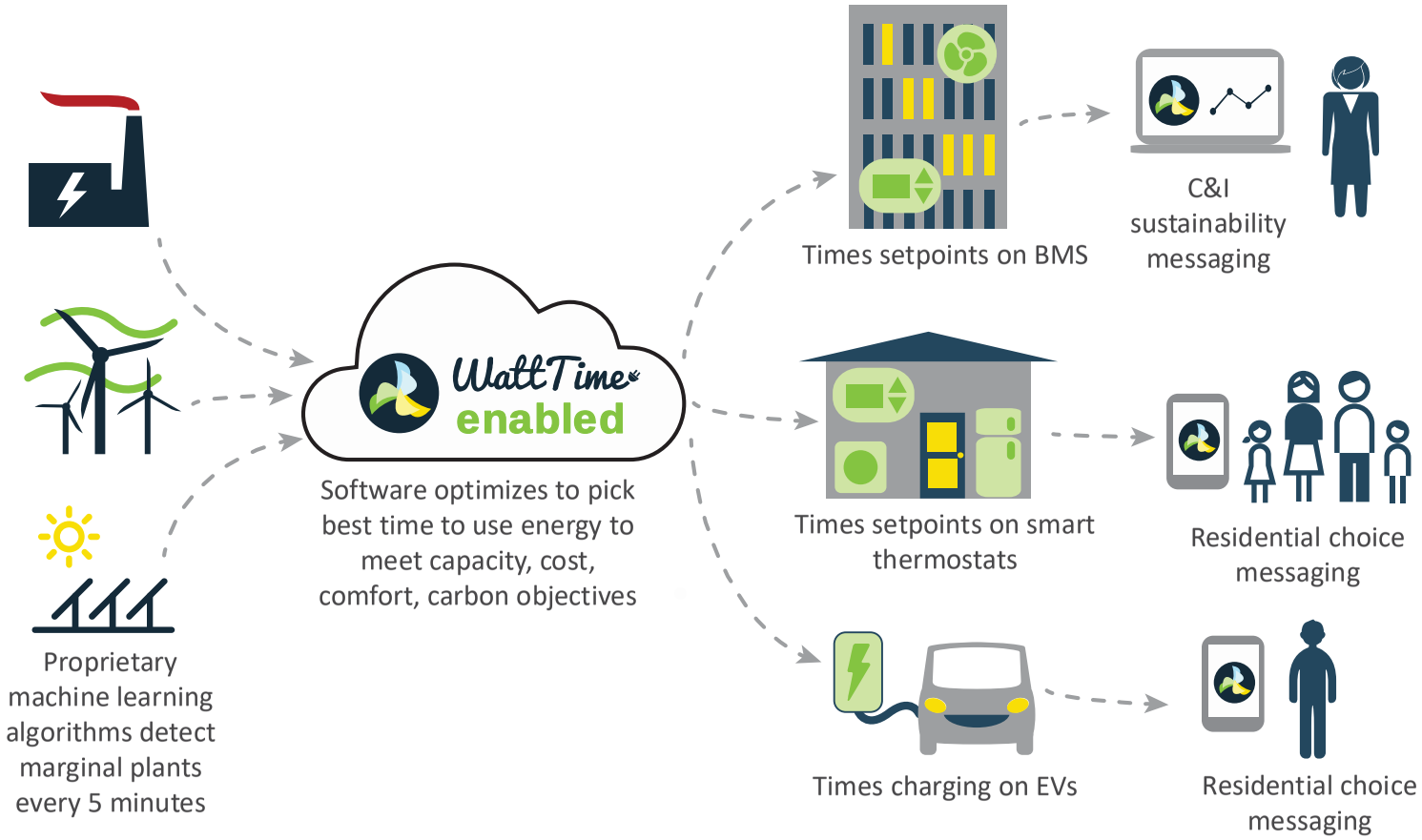
- Much electricity use is at least partially flexible in time
- E.g. devices with compressor cycles can sync cycles to cleaner moments

Example: fridge cycles





Automated Emissions Reduction Platform



DRET: Automated Emissions Reduction

https://www.etcc-ca.com/reports/automated-emissions-reduction-dispatch-signal-dr-emerging-technologies-assessment

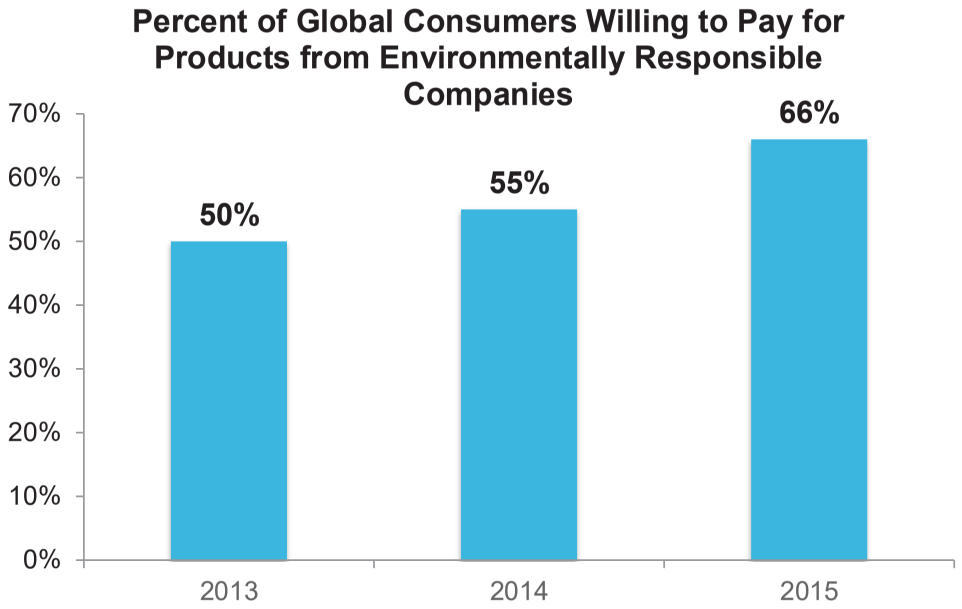
MIDAS SERVICE

Individual consumers are expecting more environmentally friendly options, and are willing to pay for them

Consumers in America want and expect more sustainable solutions

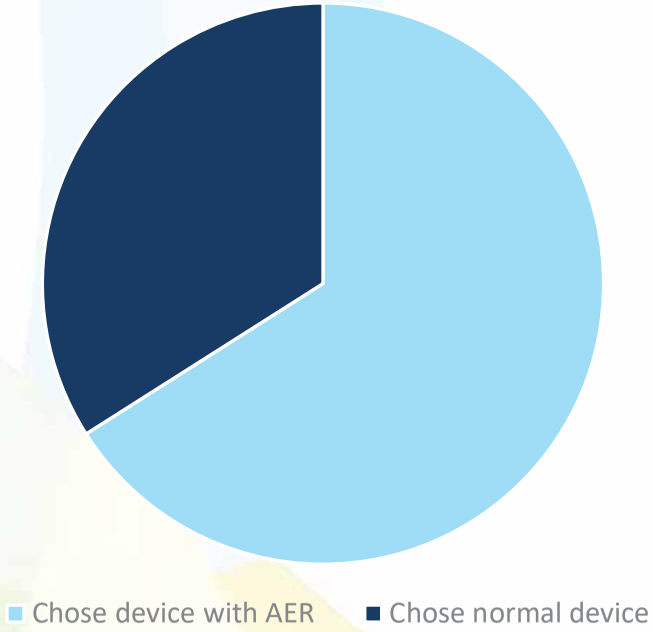
- A survey of 1,500 customers conducted by SmartEnergy IP found that 32% expect their utility to adopt automation technologies to save energy[1]
- A 2016 Gallup poll revealed that 73% of Americans want to emphasize alternative energy instead of oil and gas production[2]

Consumers are increasingly willing to pay for environmentally conscious brands [3]



Source: [1] Navigant Research; [2] Gallup; [3] Nielsen

Customer preference for AER translated into actual change in buying behavior



Study (Delta Institute):

- 100 individuals in Chicago offered a free thermostat and asked to choose between two identical devices, one with WattTime's AER feature and one without

Result:

- Yes. 2/3 of customers chose the thermostat with AER.

Demand Response Participation with AER

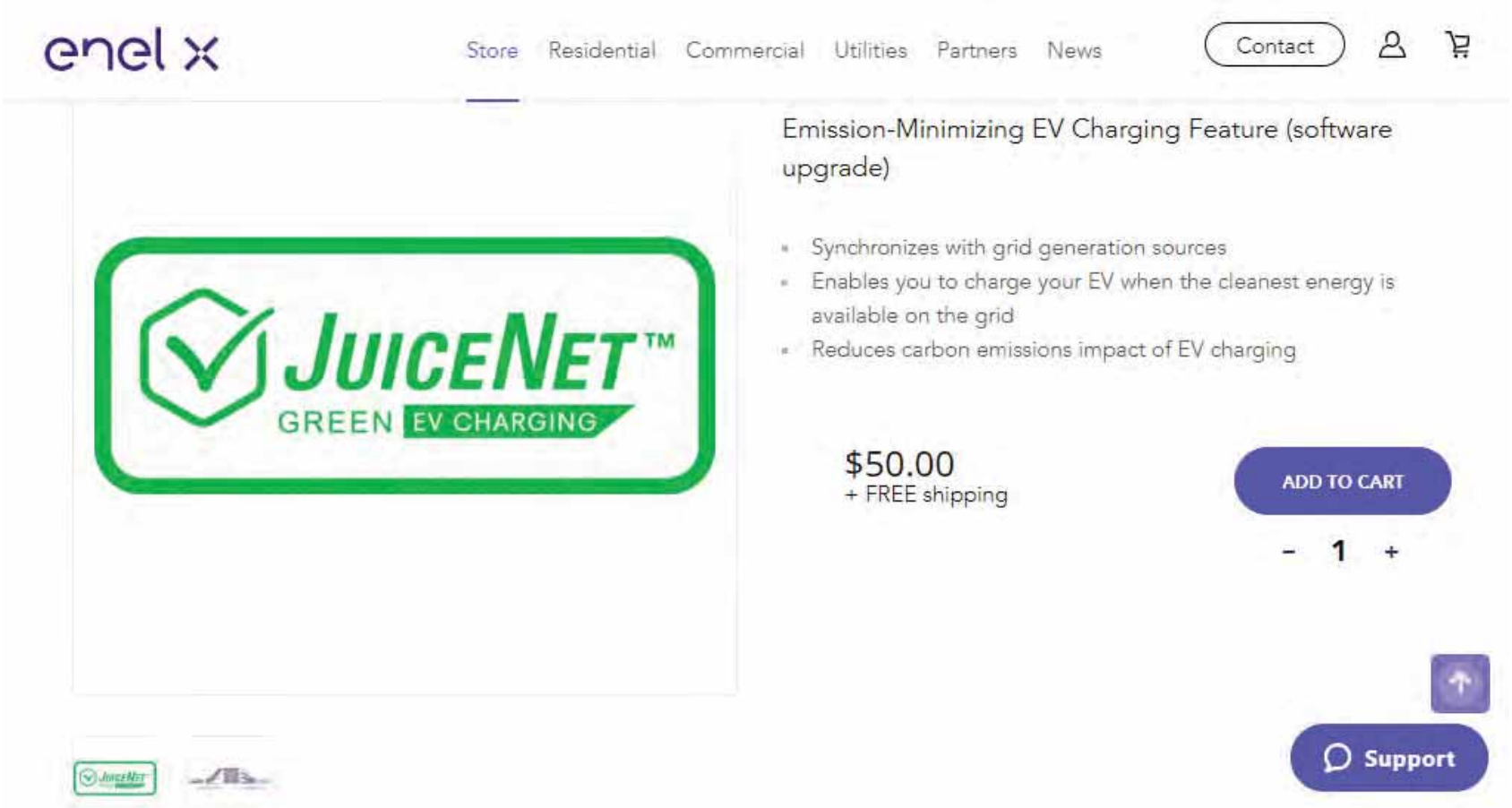
Study (WattTime):

- 300 randomly selected individuals across 30 U.S. states were asked if they would sign up for a hypothetical ADR program. Unbeknownst to these individuals, they were randomly assigned to different ADR program descriptions: a regular program, one that offered an unusually large financial incentive ($600/month per thermostat), or one with AER.

Result:

- Adding environmental impact to a DR program (by adding AER to it) increased signups. Contrary to researcher expectations, AER increased signups *even more* than financial gain did.

Existing Products



HOW EVOLVE WORKS

INPUTS

POWER PRICES

REAL-TIME DATA

- WEATHER
- CARBON
- COMMUNITY

evolve ENERGY

USER SETTINGS

- COST
- CARBON
- COMFORT

EVOLVE AI

- MACHINE LEARNING
- ANALYTICS
- MULTI-VARIABLE ALGORITHM

OUTPUTS

AUTOMATIC LOAD SHIFTING

- IOT DEVICES
- EVOLVE BATTERIES

MANUAL LOAD SHIFTING

- NOTIFICATIONS
- USER PROMPTS

MIDAS Proposal

Overlay emissions reductions and energy choice onto existing DR programs

Provide energy choice for customers

Achieve cost-effective continuous load shifting

Automated, device dependent program

Select market signals [emissions, energy, capacity, distribution, curtailment]

Thank You

Henry Richardson

Environmental Analyst

henry@WattTime.org

415.300.7475

ATTACHMENT J

PAY FOR A LOAD SHAPE

Pay for a Load Shape

Peter Alstone

Schatz Energy Research Center / Lawrence Berkeley National Laboratory

CPUC Workshop on Dynamic and Real Time Pricing (RTP)

October 15, 2019

Schatz Energy Research Center

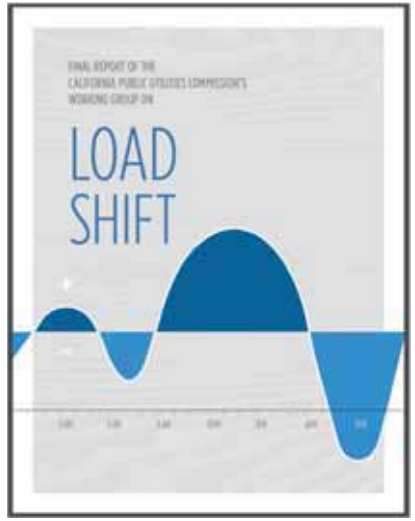
BERKELEY LAB

Context

Developed in the Load Shift Working Group.

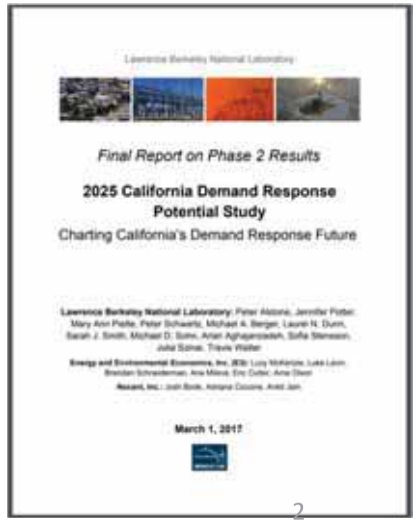
In addition to market-integrated "PDR-LSR" LSWG identified options for organizing load flexibility that were:

- Not market integrated (lower control & telemetry costs)
- Not based on rates (since it was not a rate proceeding)

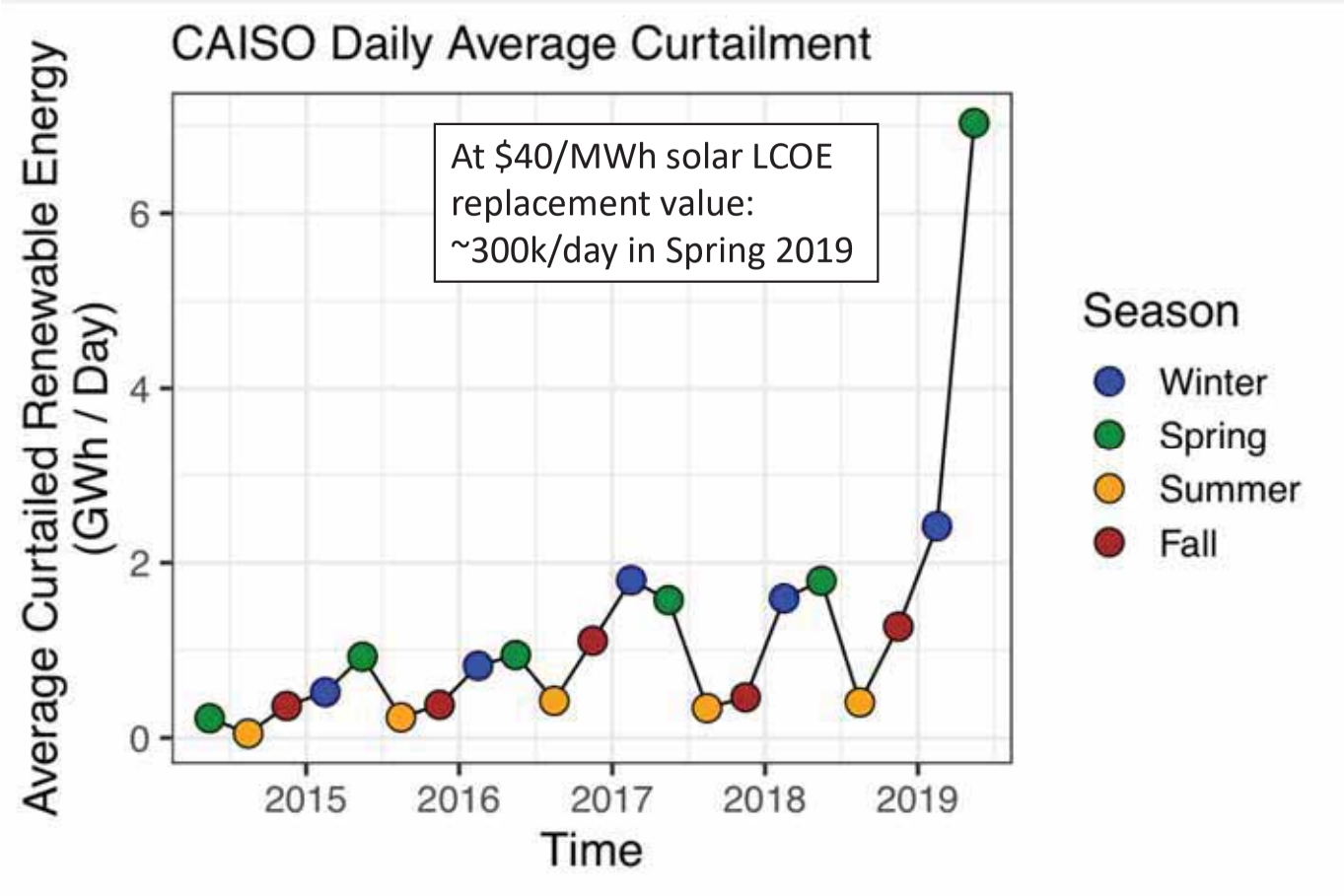


Pay-for-a-load-shape envisions a program that sets a **grid-friendly target load shape** and pays incentives to customers who match it well.

Inspired by results of **California Demand Response Potential Study** (supporting CPUC R.13-09-011)



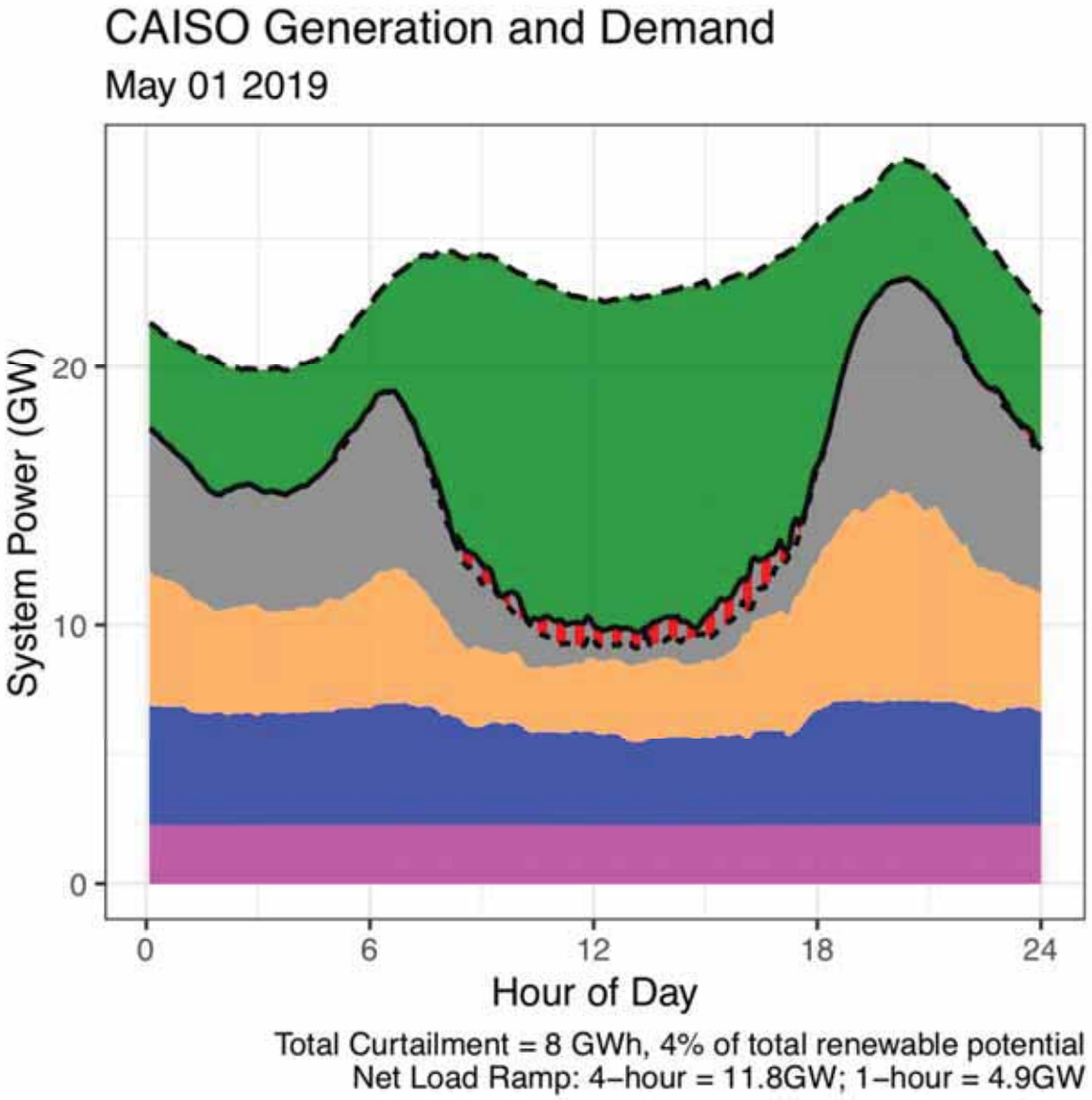
Renewable curtailment is a key driver for the value of flexible load shifts



Data on this and next several slides from CAISO "Managing Oversupply" Production and Curtailment Reports

Curtailment concepts:

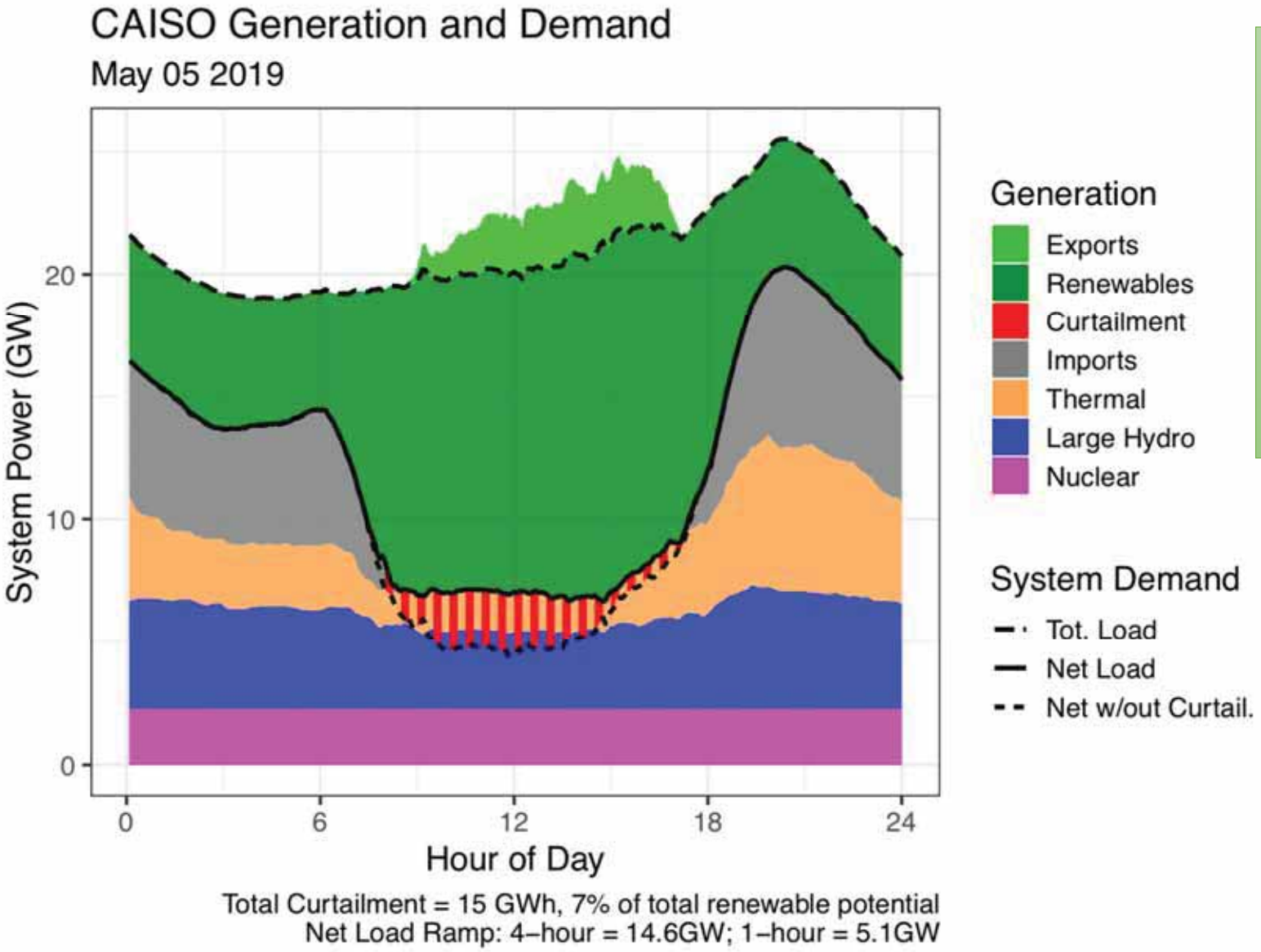
- Associated with **low net loads**
- Typically results in **zero or negative prices** in energy market
- Expected to **increase significantly as RPS goes up**
- An opportunity to capture **zero cost, low carbon resources**
- Becoming **predictable**



CAISO operations data reveal scale of curtailment today

Typical Spring 2019 day with mid-day curtailment.

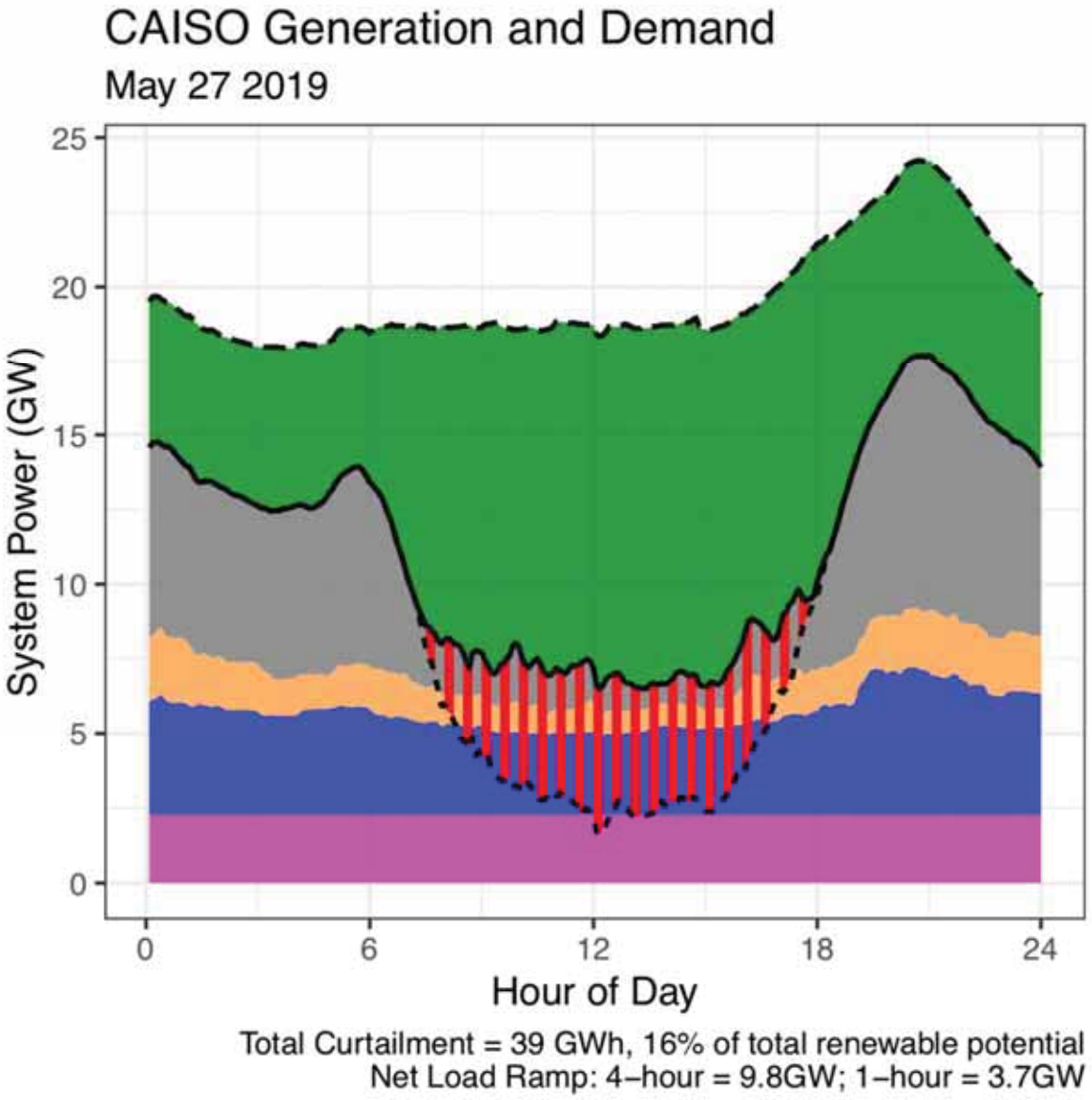
(May 1st)



Lower demand leads to ~2x the curtailment as is typical.

Exports help avoid additional curtailment.

(May 5th)



Memorial Day is an extreme case with nearly 40 GWh curtailment:

- Low demand
- Sunny day

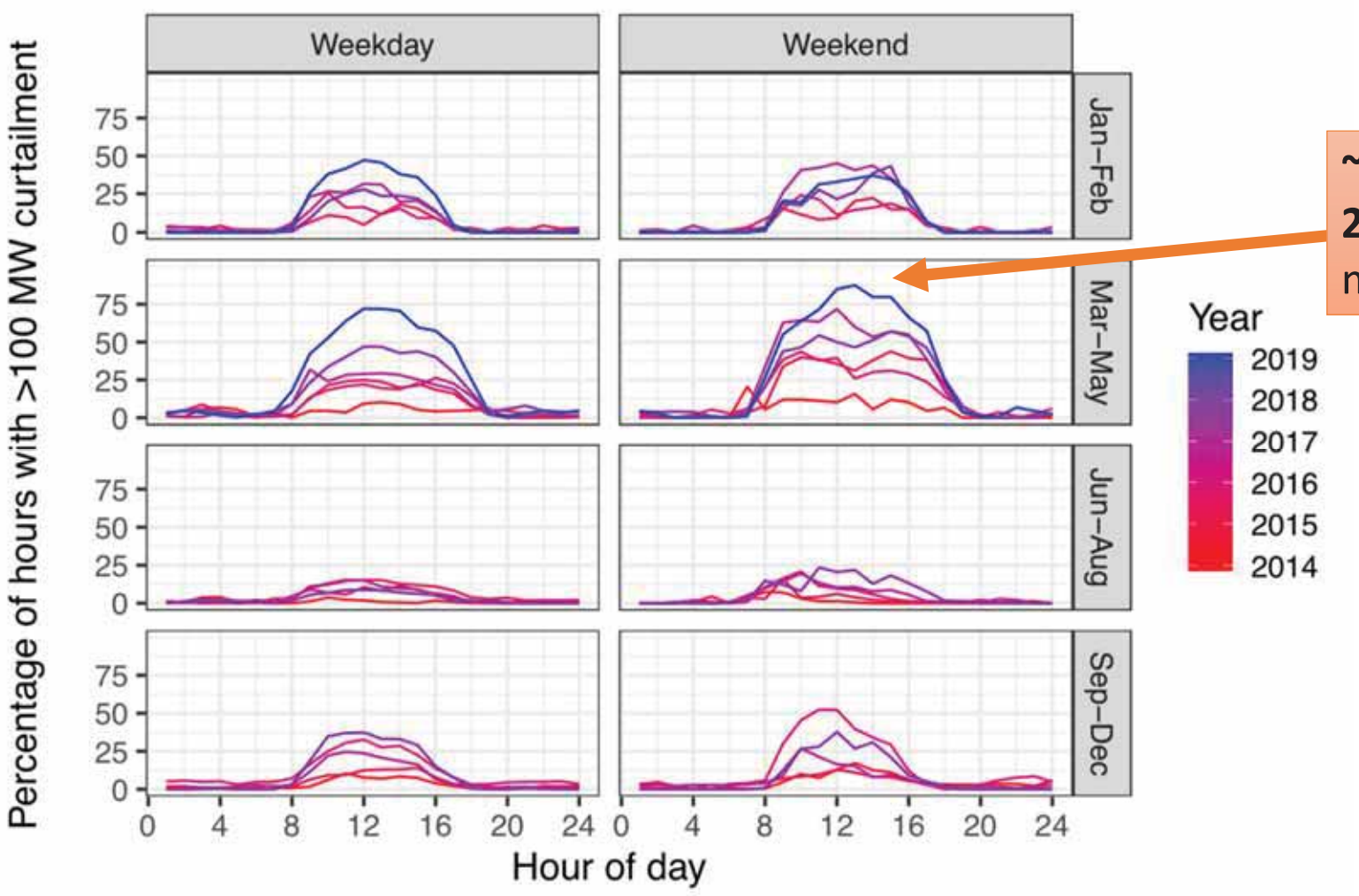
(good for the holiday!)

- No exports

(May 27th)

As curtailment grows, the **timing becomes predictable day-to-day**

Plot shows the percentage of hours with curtailment by season & day type



~75% of days in Spring 2019 had significant mid-day curtailment

“Pay for a Load Shape” (P4LS) Concept

Incentivize the “anti-duck curve”* by asking customers to restructure and/or change the daily timing of demand and match a target.

1. Utilities provide **target load shapes** that are **updated periodically**.

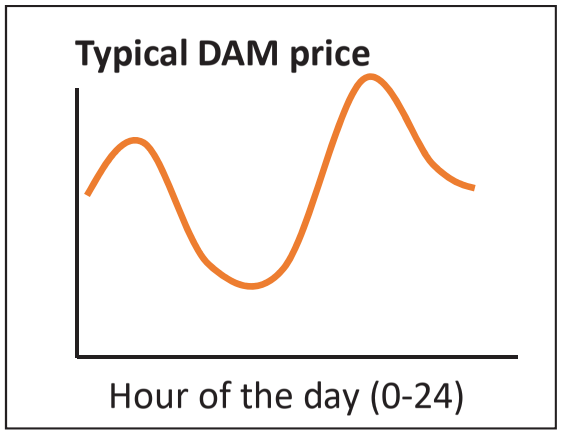
2. These targets could **incorporate both energy market marginal prices and infrastructure costs** (peak load reduction, etc.)

3. Customers modify loads and are **compensated based on reduced cost to serve loads.** Not just avoided curtailment, but also reduced fuel cost, peak cost, etc.

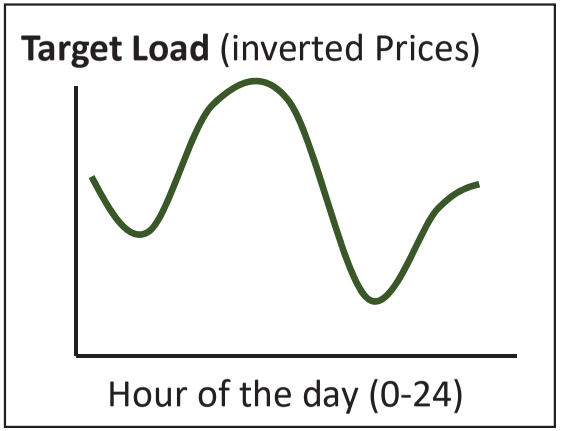
**In the DR Potential study we found the “optimal” dispatch of shift was quite similar to the inverse of the duck curve --- the “anti-duck”*

Cartoon Version

Start with cost driver

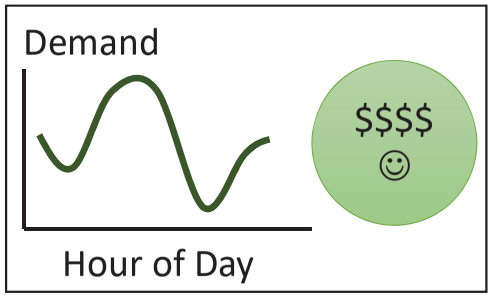


Determine Target
Load Shape

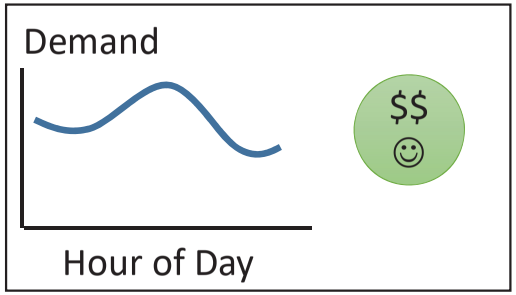


Assess performance
and pay incentives
based on reduced
cost to serve load

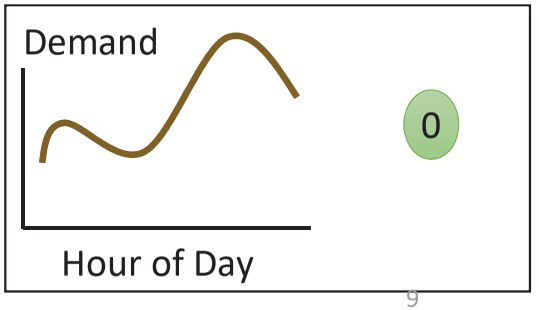
Customer A
(Great match)



Customer B
(OK match)



Customer C
(Poor match)



There are many ways to configure P4LS

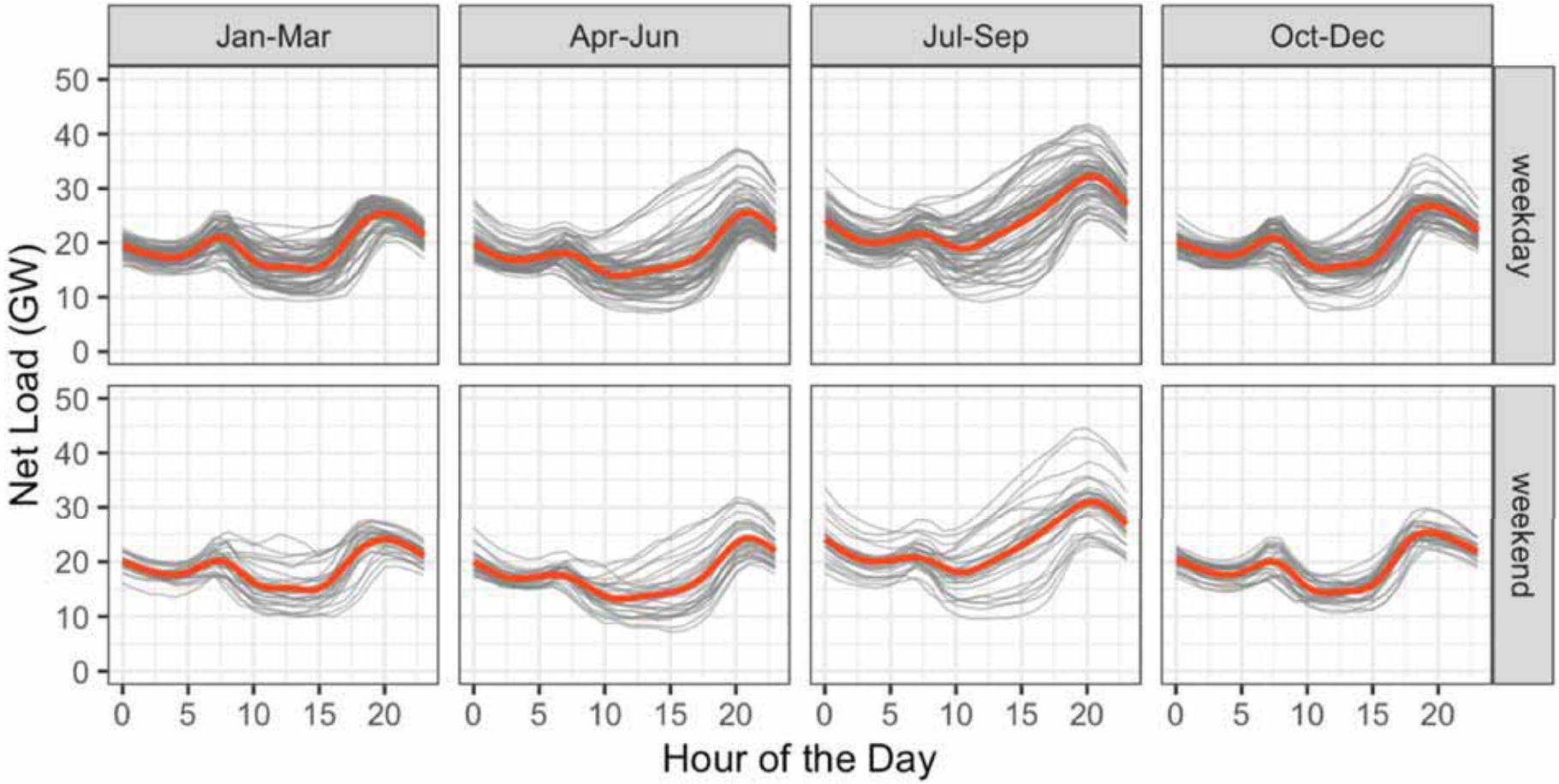
Target Basis: Loads, Prices, and Marginal Emissions could all be the basis (they are correlated in California)

Spatial graunlarity: Local Factors like **nodal prices, excess renewables** or **distribution system** constraints could be used to define local targets

Update periods: Targets could be updated **daily, weekly, monthly, etc.** There are diminishing returns to more frequent updates (analysis follows).

Net load over the course of a day in 2017

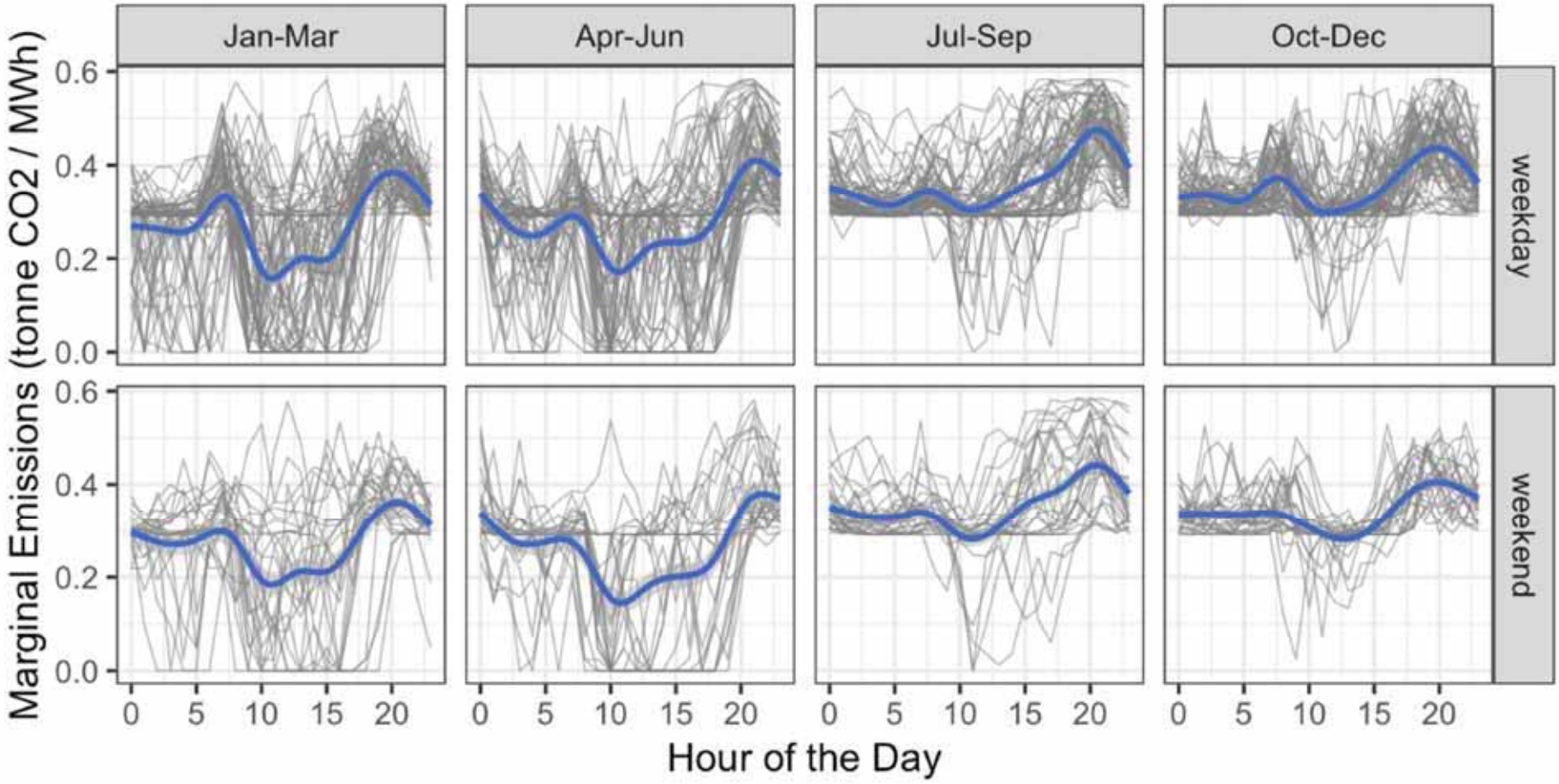
Each line is a single day; red is a line of best fit



data from CAISO Renewables Watch

Marginal CO2 emissions over the course of a day

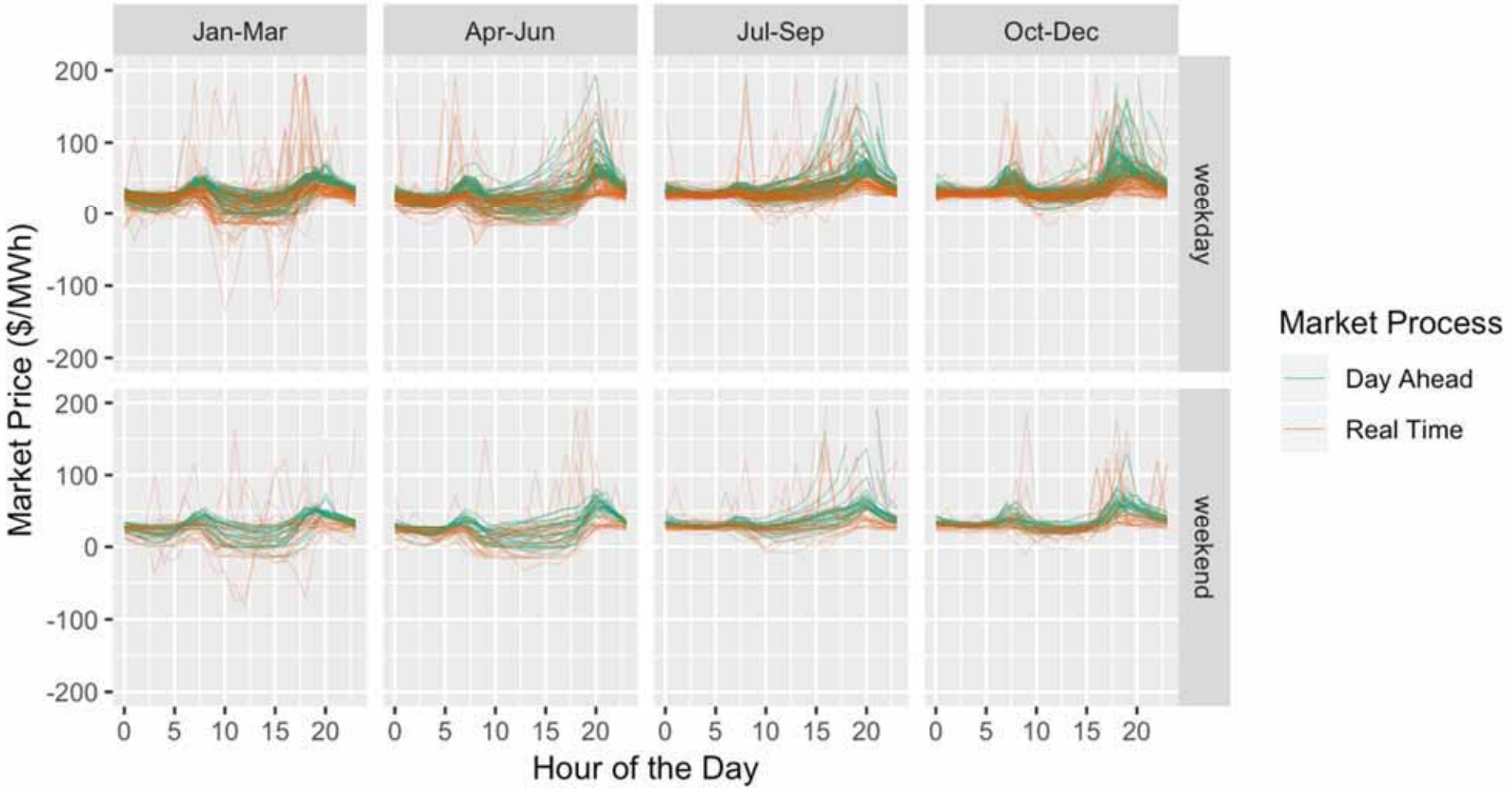
Each line is a single day; blue is a line of best fit



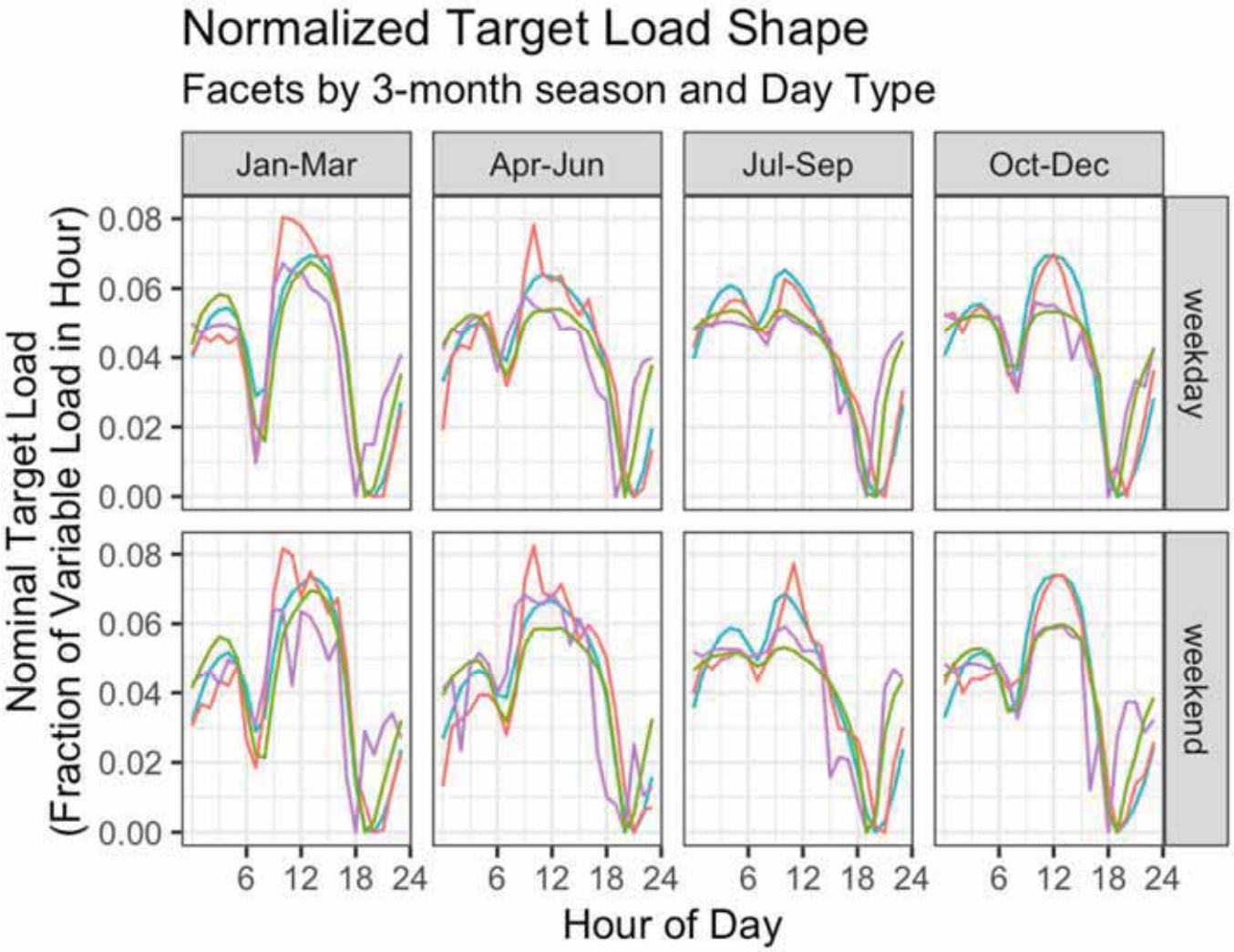
WattTime SGIP Analysis

Prices over the course of a day in 2017

Each line is a single day; Omitting periods with prices >$200



data from CAISO OASIS



The target is similar with loads, prices, and emissions. We don't have to pick between prices and emissions in CA.

Target Basis

- CO2 Emissions
- Day-Ahead price
- Net Load
- Real-time price

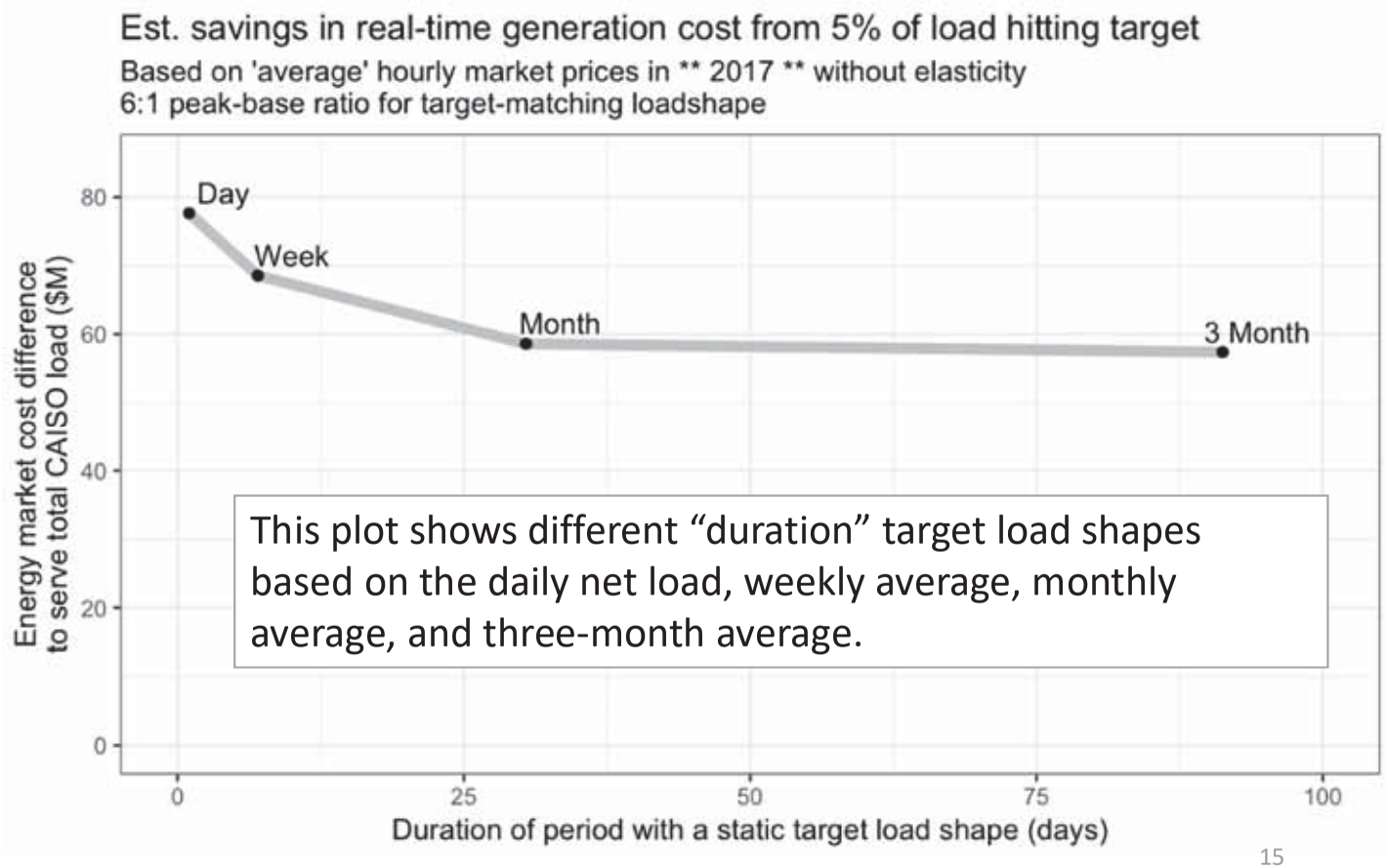
The duration of target load shape persistence changes the estimated energy market savings, but not by much.

Notional analysis:

5% of daily load participating and exactly matching the target (based on prices).

$60-80 M/year annual savings in energy costs given 2017 grid.

~30% better outcomes if the targets are updated daily vs. monthly.



P4LS and Pay for Performance

P4LS is **closely aligned with "Pay for Performance" (P4P) concept in energy efficiency**, where EE outcomes are valued based on the time of day for demand.

Since **curtailment and prices are often predictable day-to-day**, there are significant benefits from this kind of structural change.

Example Pay for Performance EE benefits from two different upgrades

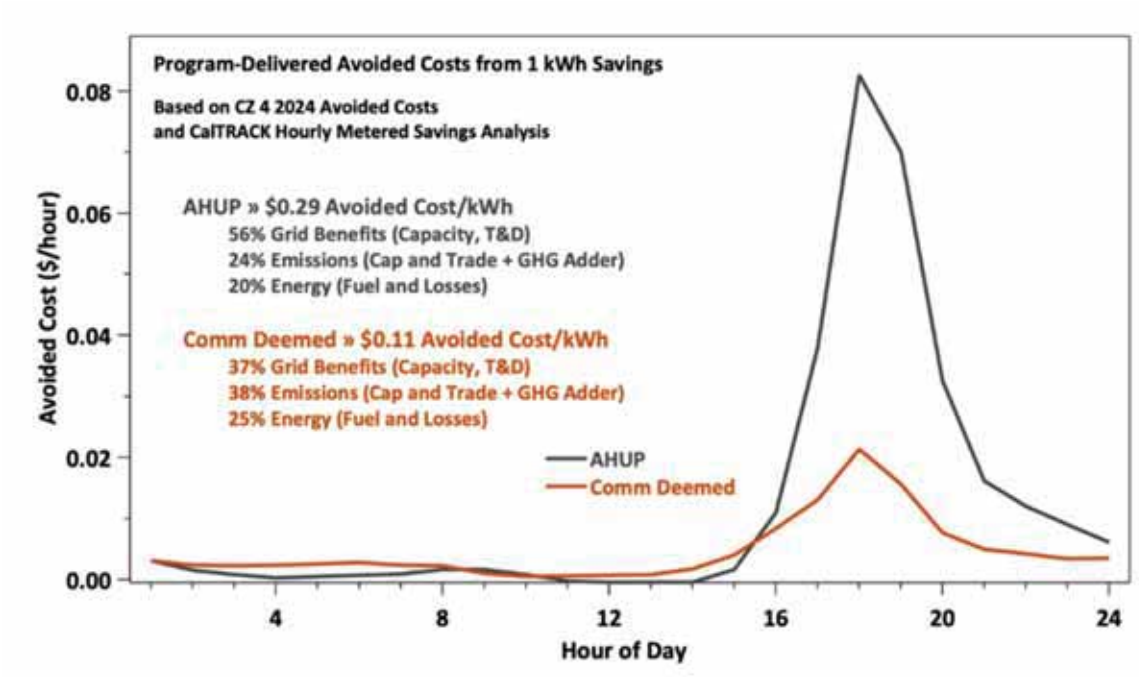


Figure from: Golden, Matt, Adam Scheer, and Carmen Best. 2019. "Decarbonization of Electricity Requires Market-Based Demand Flexibility." *The Electricity Journal*, Special Issue: Energy Optimization is the Key to Affordable, Reliable Decarbonization, 32 (7): 106621. https://doi.org/10.1016/j.tej.2019.106621.

P4LS and RTP

- P4LS was originally developed to get similar outcomes if we *can't* use RTP (e.g., because RTP is unavailable or customer class does not respond well).
- **In principle, both P4LS and RTP get to the same result** (customers with cheaper loads to serve ultimately pay less, either with incentive or bill savings).
- **P4LS can be updated more frequently than TOU but not so unpredictable as RTP**, which may balance grid needs vs. customer ability to respond.
- A key **challenge to P4LS is the need to assess avoided costs from customer responses** (similar to the "baseline" challenge for other demand response). RTP avoids these baselines, but requires careful work to structure the rate up front.

Thank you!

Contact information:
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peter.alstone@humboldt.edu

www.schatzcenter.org

DR Potential Study:
https://drrc.lbl.gov/publications/2025-california-demand-response

Potential Discussion Points

- Could aggregators put together a portfolio of customers?
- Should different customer classes have different targets?
- Are “slow changing” targets easier for managing power system?
- Is there synergy between P4LS and RTP?
  - e.g., Pay an aggregator to help customers meet a target load. The customers get bill savings and the aggregator gets some payment based on portfolio response.

Appendix: Extra Analysis

Possible Organizational Roles

Customer	**Participate, Invest in enabling technology, Respond, Get Incentives.**
Third Party / Aggregator	**Design and deliver retail programs** / products for aggregations of small and medium customers. **Incorporate into existing DR portfolios** and business models.
Load Serving Entity (CCA or IOU or DA provider)	**Define SubLAP or DLAP level target load shape** that minimizes cost of service. Publish target load shape (if appropriate)
Distribution utility / service territory LSE	**Refine target based on distribution system constraints**. Provide incentives for modified targets. Provide AMI meter data access to support settlement. Participate in publication of target load shapes and ensuring cybersecurity.
CAISO	**Support forecasts of net load / price and market data access**. Support program evaluation and valuation of response with CAISO analysis.
CPUC	**Provide regulatory oversight** for target load shape definition, publication, and verification processes? *Editorial Note: Defining the target load shape for the system-scale (before any local modifications) would weigh costs, pollution, and customer experience. How to balance public oversight need with the need for maintaining nimble response to changes in grid needs? How will non-IOU LSE's be treated in any regulatory oversight?*

A straw-proposal process concept

1. Every 3 months*, LSE's work to establish an updated **target load shape** that supports grid needs (possibly different targets for different customer classes and different geographic areas). These are published publicly after any needed modification by distribution system operators to ensure reliability, a month in advance of changes from one target shape to another.
2. Participating **customers and/or aggregators work to match loads to the target** using automated, structural, and behavioral approaches .
3. The **total savings from the reduced cost of serving customer loads is estimated** and returned to participants through incentives and performance payments.
    1. Incentive pool could include energy market operations savings, avoided generation capacity cost, avoided T&D, avoided curtailment based on evaluation of the performance of the portfolio.
    2. Performance based (or mixed fixed+performance based) incentives provide nudges for participating customers / sites to continue improving compared to the average participating customer.

*the period is a design choice and could in principle be anywhere from days to months. On a supporting slide, show a preliminary analysis of market prices to show the order of magnitude different in the cost to serve load.

For Illustrative Purposes – Look at 24 grocery store load shapes to see variability within a sector – "good" match here (a "structural winner")

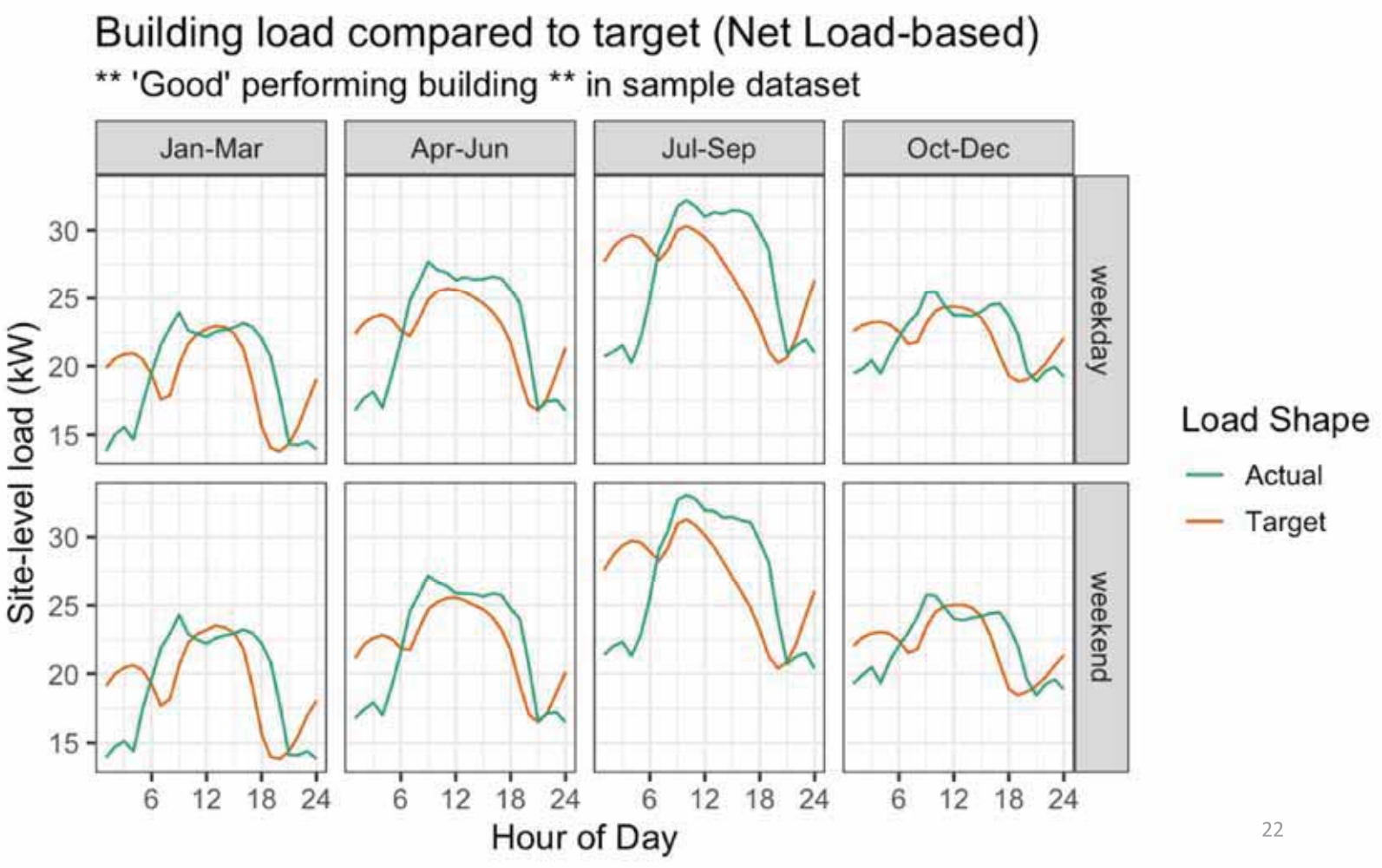
Setting the "target":

1) Find the "average" shape in the period.

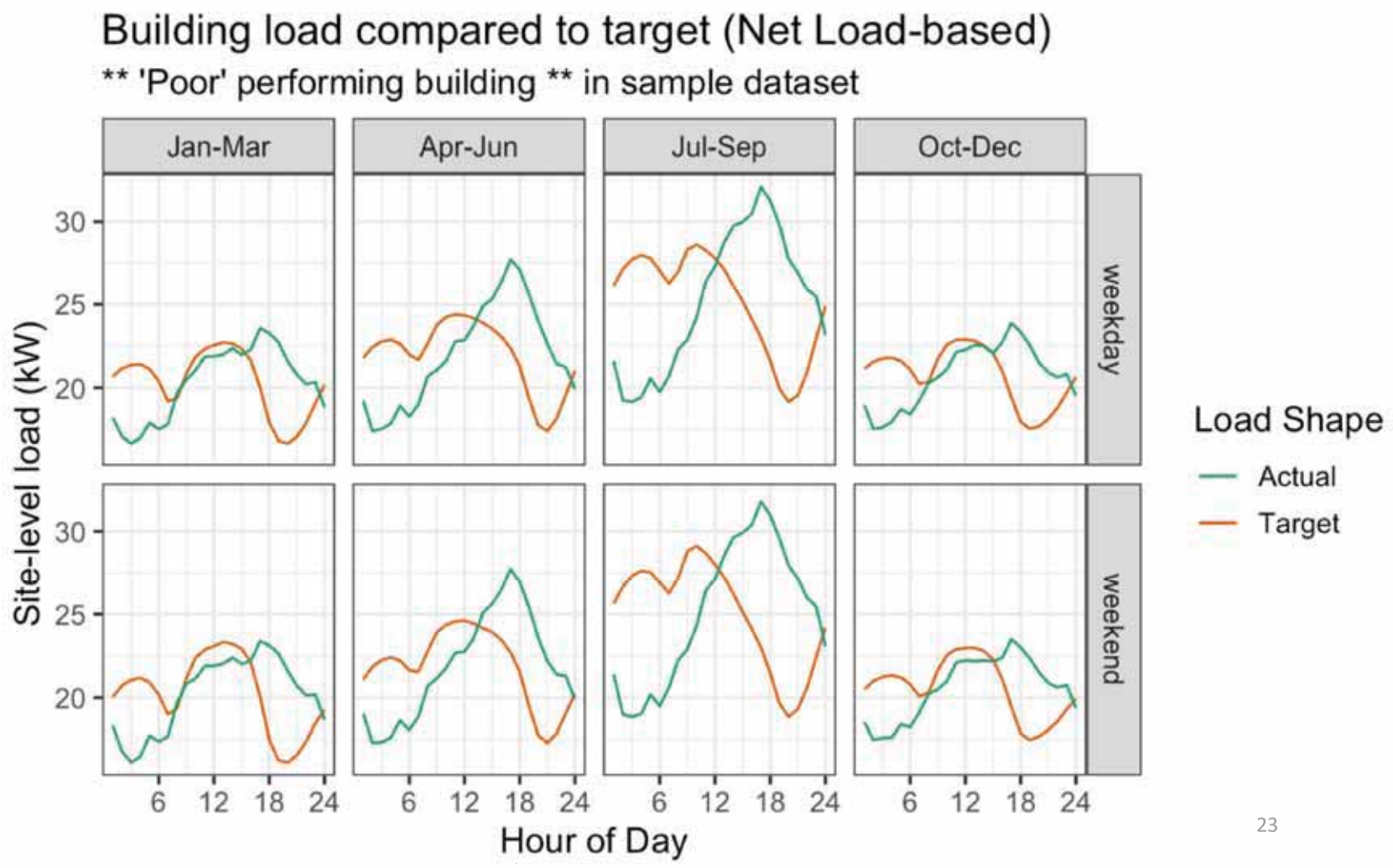
2) Identify the baseload (the minimum of the average shape).

3) The target is the baseload plus a "new" variable load that is rescaled to match the system target shape.

The total load is the same in target vs. actual.

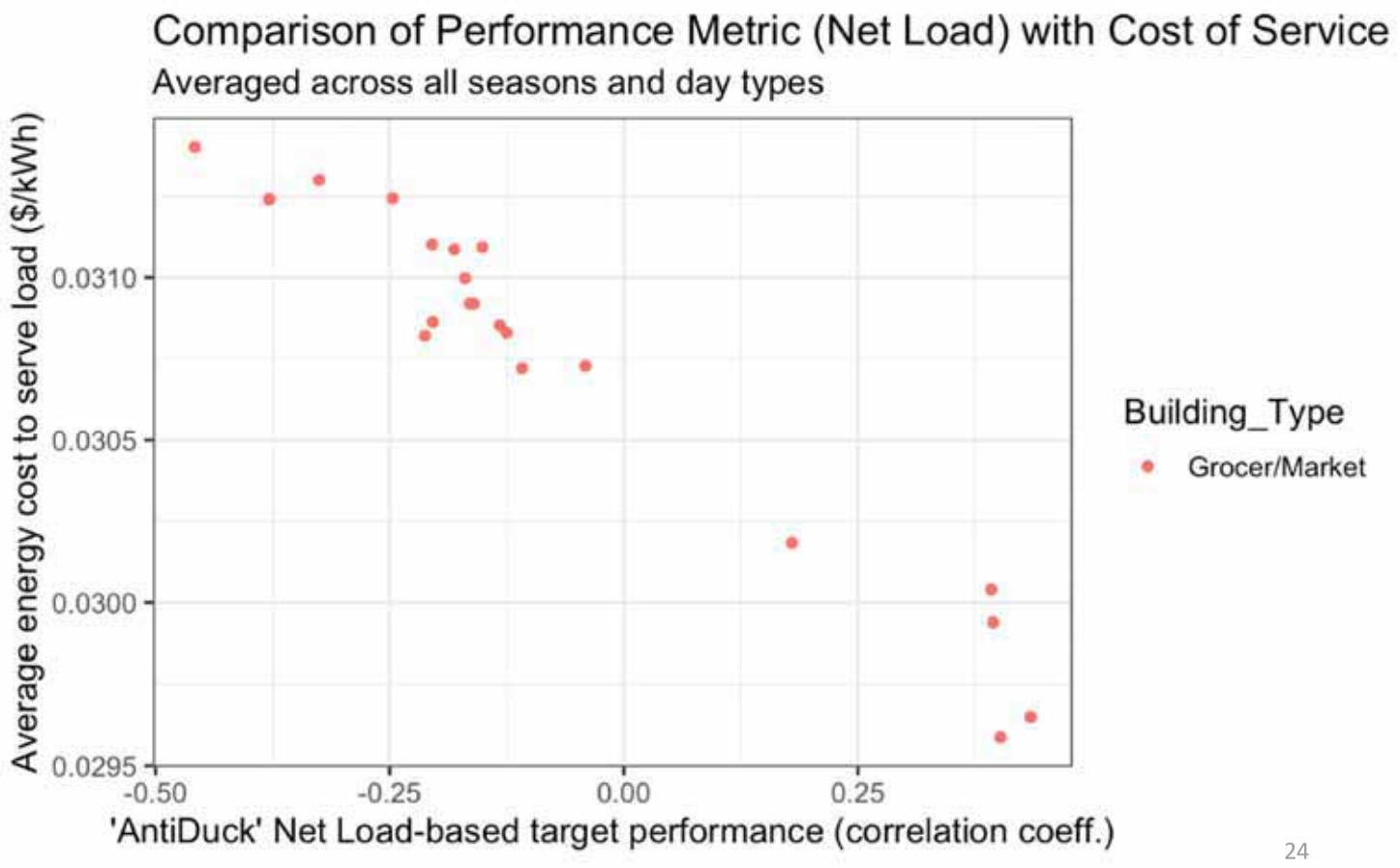


Poorly performing sites have worse match between actual and target loads



Better-performance (higher scoring) sites are less costly to serve.

A correlation-based performance metric (comparing target to actual load) is strongly related to the cost to serve loads at the sites.



Point of reference for scale:

The unit cost savings ($/MWh) from shifting estimated on the previous slide are $25-30 per Shifted MWh.

These are roughly consistent with E3 RESOLVE model estimates used in the DR Study (to the right)

A relatively low value in the market is consistent with DR potential study results for current-day grid operations. **As curtailment (and average price differentials) increase over time, this value should go up.**

FIGURE FROM THE DR Potential Study

As shown in Figure 39, the savings from Shift resources increase at all penetration levels as we move closer to 2030. Recall that savings from DR assessed over the entire 2016–2030 period were allocated to individual years using the relative percentage of base case curtailment in each year. RESOLVE estimated increasing curtailment as we moved closer to 2030 and the assumed 50 percent RPS.

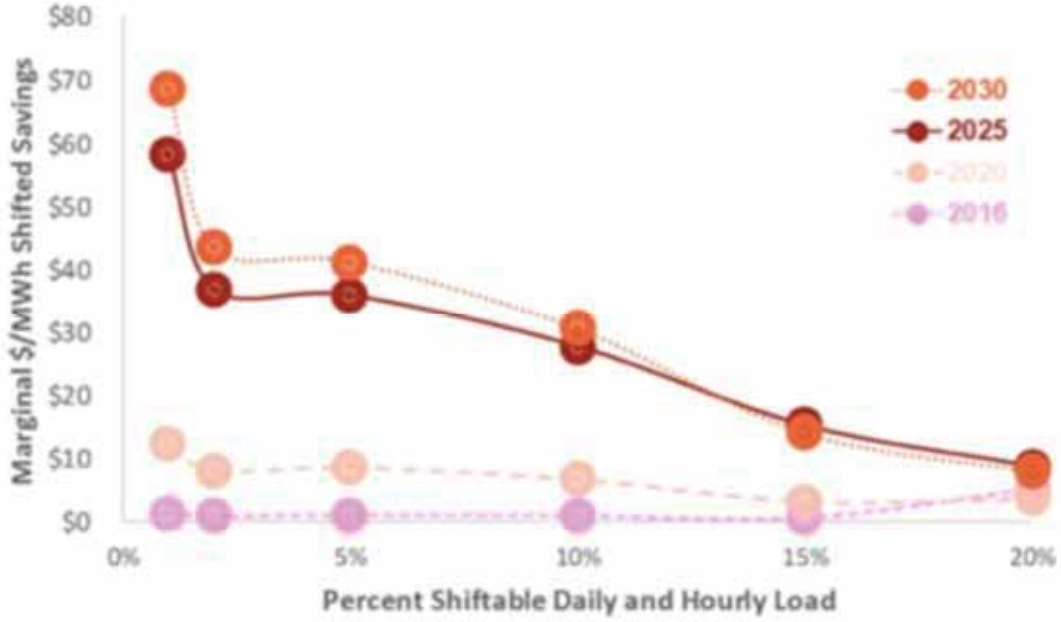


Figure 39: Marginal savings per MWh shifted, by year. High-Curtailment future, mid-AAEE scenario.

ATTACHMENT K

BRING YOUR OWN DEVICE OPPORTUNITIES WITH DYNAMIC RATES

sunrun

Bring Your Own Device Opportunities with Dynamic Rates

Creating a Planet Run by the Sun

CA Public Utilities Commission | Oct 15, 2019

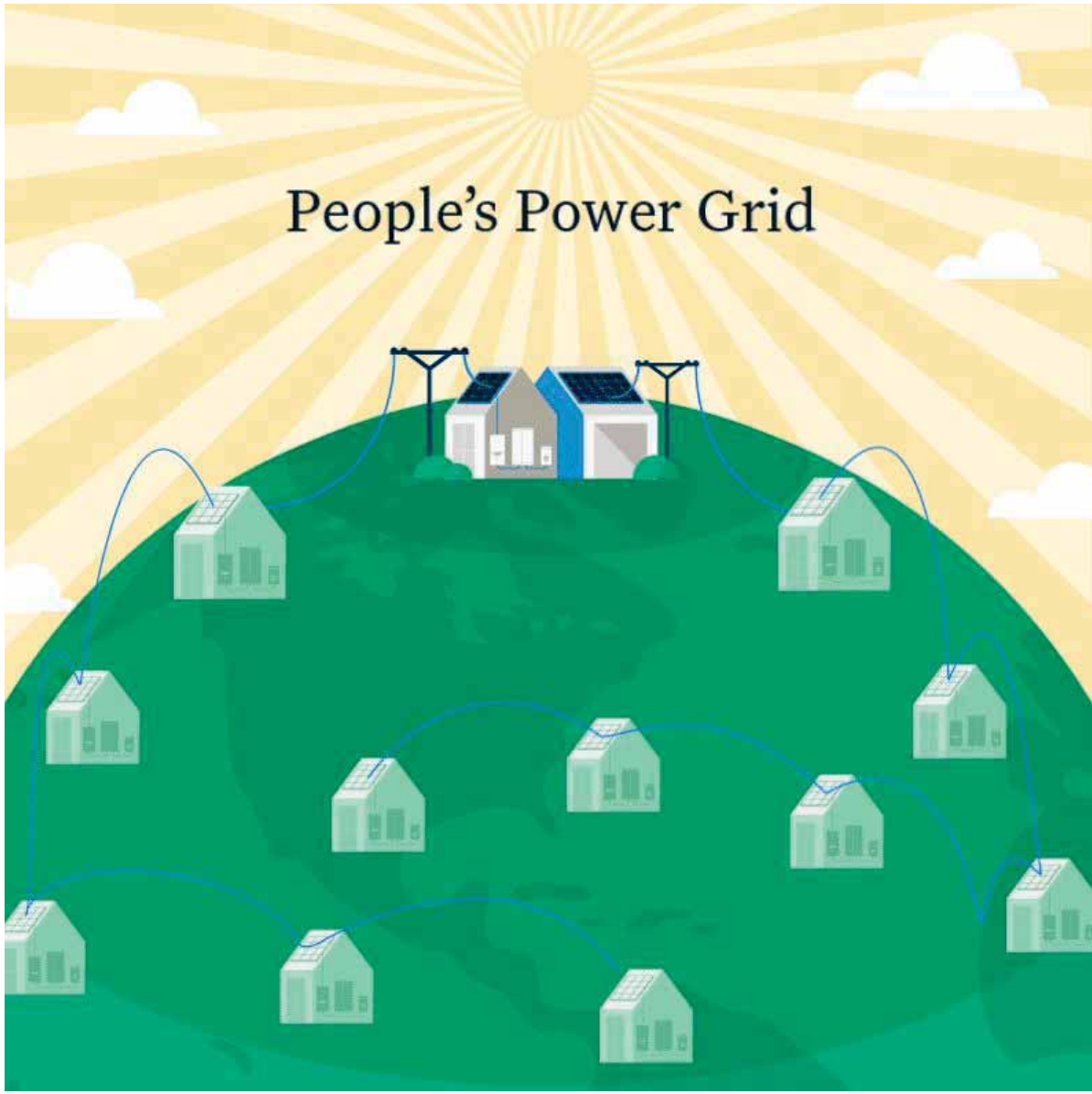
Audrey Lee, Ph.D.
Vice President, Energy Services

NEM 2.0: Customer experience with time of use rates

Bring Your Own Device (BYOD) Programs

Utility + Competitive Partnership

- Utility identifies need, predicts peak/sends signal or sets discharge profile, does settlement.
- Competitive companies finance, manage, and assume all risk.
- Participating customer receives backup power and energy savings at lower cost, minimal complexity.
- ALL ratepayers receive savings without ratebase risk.
- VT, NH, MA, RI, NY; west coast



Massachusetts National Grid BYOD Program

BYO Thermostat	BYO Device	2018 BYOD	2019 BYOD

Simple
~1 kW/home
20 events/yr
Customer fatigue
$20 upfront, $25/yr

Flexible
~2.5-4.5 kW/home
Daily events
Recharge constraints

Pay for performance
$70/kW-year
Summer only
2-5 pm
Exports not counted

national grid

EnergyHub

Exports valued
2-7pm
3 hour/event
Summer (June-Sept):
$225/kW-yr
≤ 60 events
Winter (Dec-Mar):
$50/kW-yr
≤ 5 events

sunrun

sonnen

Pika ENERGY

TESLA

solaredge

https://www.nationalgridus.com/MA-Home/Connected-Solutions/BatteryProgram

Load shift working group proposals from Sunrun

1. Distribution Load Shift (DLS) Product
    - ≈ Pay for Load Shape (P4LS)
    - + Distribution Services
2. Market Integrated Distribution Service (MINTDS) Product
    - ≈ Load Shift Resource 2.0 (LSR 2.0)
    - + Distribution Services
    - Utility as Distribution System Operator
    - Utility-offered tariff via aggregators

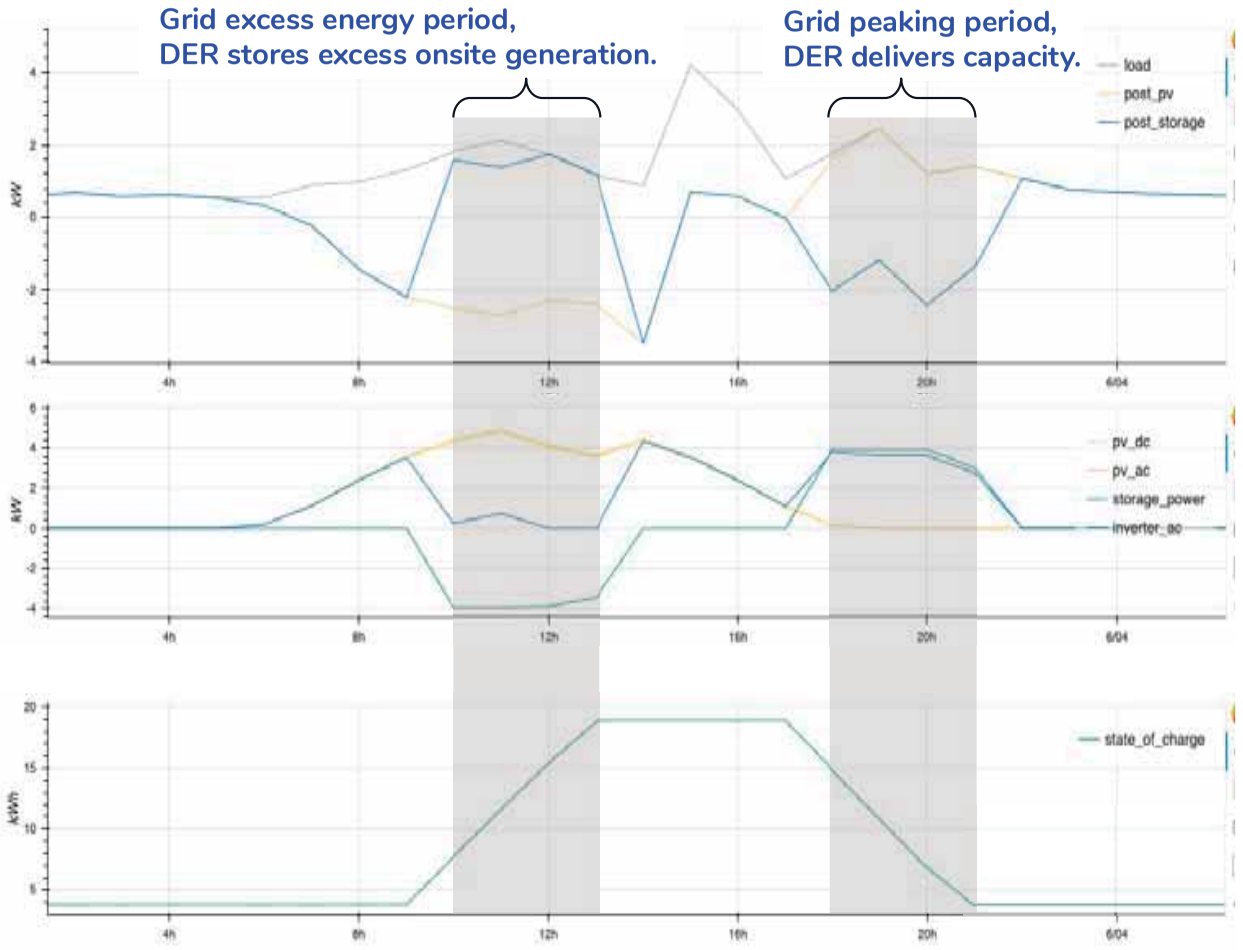
https://gridworks.org/wp-content/uploads/2019/02/LoadShiftWorkingGroup_report.pdf

Distribution Load Shape (DLS) Product: Illustration

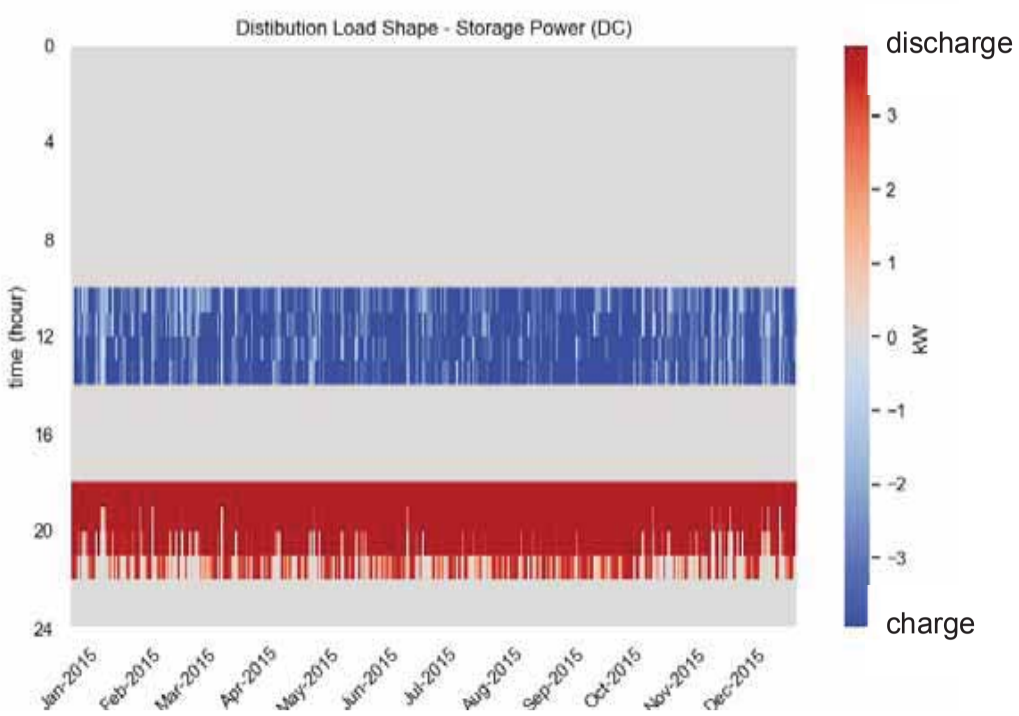
Utility meter reading or net load at residential customer site, hourly intervals

System power flow

Battery state of charge



Distribution Load Shape (DLS) Product



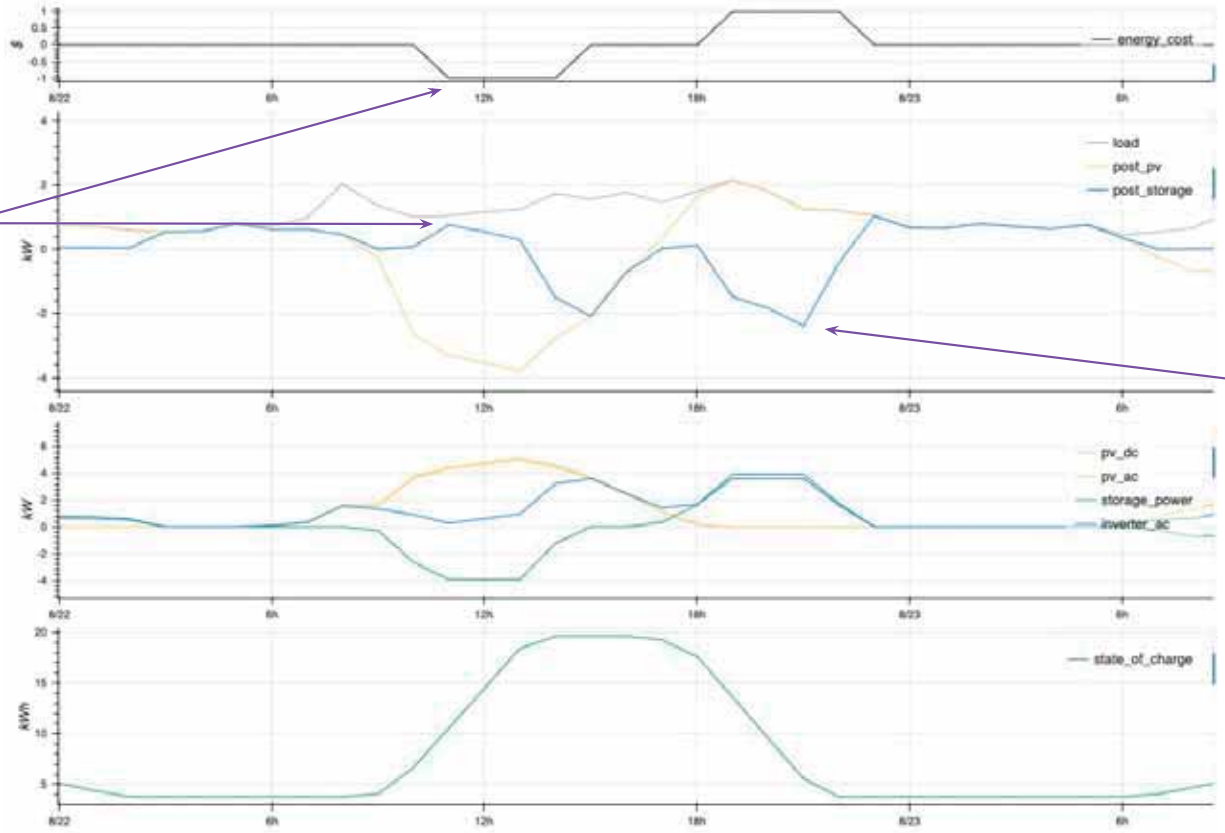
Approach Benefits

- Easy to program/schedule DER and account for within **interconnection** and **planning** processes.
- DSO/CCA **coordinated** response to align with excess energy and peaking capacity needs for the benefit of all regional customers.
- Optional rider tariff stackable with **NEM** and receives **capacity payment** for beneficial permanent load shape.
- **Hosting capacity** expansion/deferral benefits if coordinated holistically within interconnection processes.
- Available to **retrofit** existing (if needed) and future DER customers with capabilities to provide coordinated capacity services.

Note: single schedule shown for simplicity, but other schedules possible.

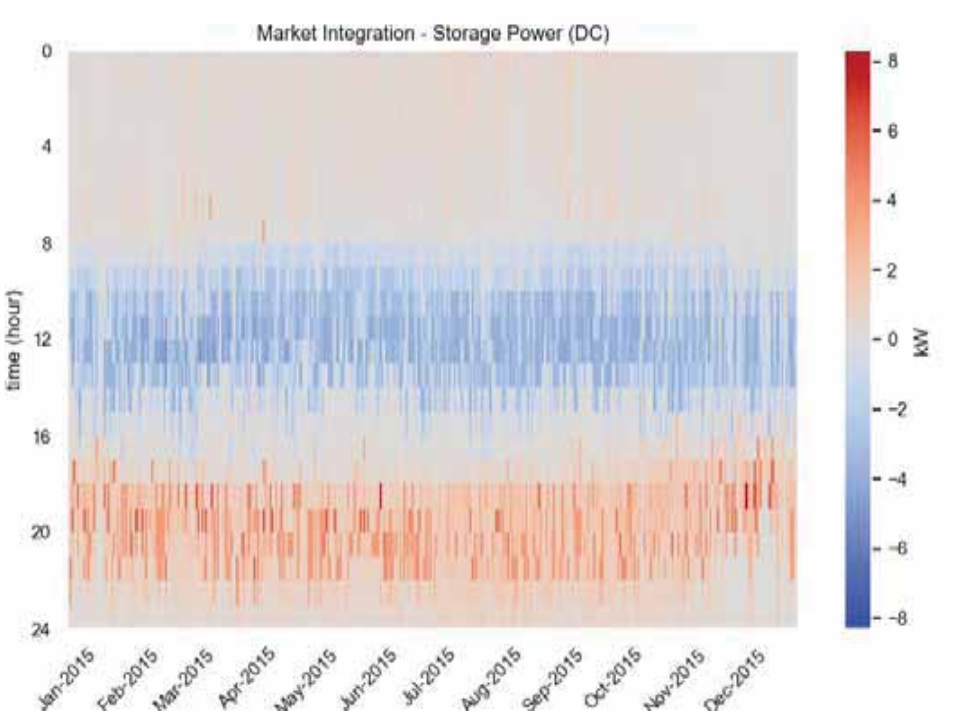
Market Integrated Distribution Service (MINTDS) Product: Illustration

During negative price signal: Battery charges from rooftop solar eliminating exports and resulting in positive demand from the grid.



During positive price signal: Battery discharges at high power resulting in net export to grid.

Market Integrated Distribution Service (MINTDS) Product



Approach Benefits

- **Real time dispatchable** load shift product.
- DSO/CCA dispatches resources to align with excess energy and peaking capacity needs for the benefit of all regional customers.
- Unlike CAISO's PDR, customer resources are able to self consume during peaking period with alternative baseline allowing for DER Capacity **export**.
- Optional rider tariff stackable with **NEM** and receives performance based **capacity payments**.
- **Hosting capacity** expansion/deferral benefits if coordinated holistically within interconnection processes.
- Available to **retrofit** existing and future DER customers with capabilities to provide coordinated capacity services.

Harness customer investments & Advance system planning To plan for the future and lower costs for all

- Utility and CCA **Bring Your Own Device** (BYOD)/rider tariff programs are designed for customers to respond to dispatch signals for coordinated aggregated response.
- Consider the impact/**inequity** of exposing customers to local/regional high pricing.
- Don’t simply hope customers respond to high prices.
- Resources participating in BYOD programs are better suited for **coordinated real-time dispatching** than individual customers responding to real-time rates.
- BYOD programs encourage **technology adoption**.
- **Protect customers** unable to adopt new technology and exposed to real-time pricing.
- Don’t forget about **distribution hosting capacity** coordination benefits as one of four Multiple Use Applications stacked within these BYOD programs.

ATTACHMENT L

INCOMPATIBILITY OF DYNAMIC RATES AND DEMAND CHARGES

Dynamic Rates vs Demand Charges

Lisa McGhee
San Diego Airport Parking
October 15, 2019

Disclosure for Technical Rate Questions:

Please send questions to: lisamcghee@aol.com

SDAP in Brief

- SDAP owns and operates a shuttle bus fleet serving the San Diego Airport and its customers, providing parking and shuttle service to and from the airport 24/7 and 365 days per year.

- We have been a SDG&E Small Commercial class customer since beginning business in 1991 and thereby had never exceeded 20 kW nor been exposed to any demand charges in our SDGE billings;
  - After adopting Battery Electric Vehicles in 2015, SDAP was faced with Demand Charges for the first time.

- SDAP has operated over 100,000 EV fleet miles with plans to be 100% electric in 2020 with the fleet and also provides EV charging for customer cars while parked.
  - **However, due to low load factors and operational needs for peak charging, electric shuttle operations will not be economic if SDAP must incur demand charges.**

SDAP's participation in RTP pilots

- SDAP was a party in the transportation Electrification SB350 Priority Review and Standard Review Pilot proceedings.

- We are a site host for SDGE's ***Green Shuttle*** and the ***Power Your Drive*** pilot programs.

--Which includes two DCFC chargers at 60 kW each and 10 Level-2 AC chargers at 6.2 kW each, establishing a Total load of 180 kW of EV Charging.

SDAP's participation in RTP pilots(2)

Both pilot programs are on the piloted real time pricing plans, with the Dynamic Day Ahead hourly rates.

This rate design consists of a flat volumetric base rate, plus **CAISO day-ahead hourly market rates, combined with the CPP and D-CPP adder fees when events are triggered.**

- **These rates may be problematic for fleets like SDAP because the business may not have the flexibility to curtail on peak, due to operational needs and the limited range of the MHD electric vehicles.**

An Annual Snap shot of The CAISO Hourly Pricing Range for VGI and Public GIR Pricing

	A	B	C	D	E	F
	Price Value	KWh Name	Qty / Hours	Price Range	%	Hours
1	-	Neg. to Cheap	61	'Negative - .01095 to -.000000		
2	0.00001	Cheap	4,675	.000001 to 4.0 cents	54.06%	4,736
3	0.04000	Average	2,423	Over 4 and up to 6 cents	27.66%	2,423
4	0.06000	Mid Price	1,427	Over 6 and up to 14.9 cents		
5	0.15000	High	141	15 and up to 34.9 cents		
6	0.35000	Super High	33	35 cents and up to $1.01	18.28%	1,601
			8,760		100%	*8,760*

July 24, 2018 CAISO pricing – 24 hours

(SDAP DR-02, Q1, 18-12-006, SDGE Response 6-7-19)

07/24/18	1	63.10986	0.06311	Mid Price
07/24/18	2	53.86854	0.05387	Average
07/24/18	3	44.72702	0.04473	Average
07/24/18	4	43.59823	0.04360	Average
07/24/18	5	41.72757	0.04173	Average
07/24/18	6	47.10022	0.04710	Average
07/24/18	7	106.61232	0.10661	Mid Price
07/24/18	8	104.42586	0.10443	Mid Price
07/24/18	9	76.53968	0.07654	Mid Price
07/24/18	10	108.86970	0.10887	Mid Price
07/24/18	11	181.35944	0.18136	High
07/24/18	12	227.81078	0.22781	High
07/24/18	13	383.79727	0.38380	Super High
07/24/18	14	366.94717	0.36695	Super High
07/24/18	15	379.09506	0.37910	Super High
07/24/18	16	401.48276	0.40148	Super High
07/24/18	17	510.39496	0.51039	Super High
07/24/18	18	587.23810	0.58724	Super High
07/24/18	19	948.46295	0.94846	Super High
07/24/18	20	1,007.51483	1.00751	Super High
07/24/18	21	647.06630	0.64707	Super High
07/24/18	22	313.62950	0.31363	High
07/24/18	23	241.56523	0.24157	High
07/24/18	24	176.33292	0.17633	High

Question for the RTP Experts

In 2018 the CAISO Day-Ahead hourly price exceeded 35 cents per kWh in 33 hours, with a maximum of $1.01 per kWh.

If that hour had been a CPP event hour, would the super-position of a $1.01 market price and a CPP adder result in double-counting capacity costs?

AL-TOU-CPP is SDG&E's "Standard" M/L C&I Dynamic Rate

AL-TOU-CPP features:

- **A Critical Peak Pricing (CPP) rate; and**
- **A Base (T&D) rate consisting mostly of Monthly Demand Charges.**

Summer AL-TOU Demand Charge Rates ($/kW)			
	Distribution	Transmission	**Total (T&D)**
Peak-Related	14.27	3.15	**17.42**
Non-Coincident	9.12	15.11	**24.23**
Total	**23.39**	**18.26**	**41.65**

AL-TOU-CPP is Problematic:

The Two Halves of the AL-TOU-CPP Rate May Conflict:

- The CPP Rate is intended for Demand Response.
- Non-Coincident Demand Charges support load flattening, and may work against demand response.
- Monthly demand charges are problematic for Demand Response.

The Commission could consider:

- Avoiding Monthly Demand Charges in T&D Base Rates.
- Volumetric TOU Base Rates could be the best pairing for dynamic and RTP commodity rates.
- Alternatively, a Daily Coincident T&D Demand Charge could work well with dynamic rate and RTP.