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 AUGUST 19, 2019 AND AUGUST 29, 2019 RULINGS DIRECTING SAN DIEGO GAS & ELECTRIC COMPANY TO FILE AND SERVE A DEMAND CHARGE WORKSHOP REPORT

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September 12, 2019

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I. INTRODUCTION

Pursuant to the California Public Utilities Commission's ("CPUC" or "Commission") Rules of Practice and Procedure, the Administrative Law Judge's ("ALJ") August 19, 2019 Email Ruling Providing Notice, Agenda and Directions for August 27, 2019 Workshop, and Ordering Paragraph ("OP") 1 of the ALJ's August 29, 2019 Email Ruling Providing Further Directions Regarding Workshop Report, San Diego Gas & Electric Company ("SDG&E") respectfully submits this Response to the above rulings. OP 1 of the August 29, 2019 Ruling states that "SDG&E shall file and serve a report that summarizes the presentations and discussions that occurred during [the] August 27, 2019 [demand charge] workshop [and that] this workshop report shall be due no later than September 12, 2019."

Per the ALJ's Rulings, SDG&E hereby submits the Demand Charge Workshop Report and Summary of Presentations and Participant Comments (Attachment A) along with parties' presentations from the Workshop (Attachments B through F).

Respectfully submitted,

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September 12, 2019

ATTACHMENT A

Demand Charge Workshop Report
Summary of Presentations and Participant Comments

Summary of Presentations

Enel X

- Enel X presented a framework for comparing different retail rate design options, wherein customer-sited energy storage systems' modeled dispatch was used to illustrate the load-shifting behavior incentivized by each rate structure and the resulting impact on marginal generation costs, marginal distribution costs, and greenhouse gas emissions. In the preliminary modeling presented, generation-cost data came from CAISO real-time five-minute wholesale prices, GHG data followed the Itron/E3 implied-heat-rate methodology used in the SGIP proceeding, and marginal distribution-cost data came from a sample PG&E feeder used during SGIP GHG Technical Working Group modeling.
- Four retail rates were modeled: SDG&E's current AL-TOU commercial rate, PG&E's upcoming B-19S Option S commercial rate, SDG&E's pilot VGI electric vehicle charging rate, and a modified version of the VGI rate.
- Marginal GHG emissions rates, marginal generation costs, and marginal distribution costs are highly dynamic over time, and there is not a strong correlation between individual-customer load (in the case modeled, for a midday-peaking commercial office building) and grid costs.
- SDG&E's VGI rate does not feature demand charges, and instead recovers capacity costs using Critical Peak Pricing adders during both the top 150 system-peak hours as well as the top 200 circuit-peak hours. Enel X's rate-design straw proposal retains this structure for recovering capacity costs but modifies the remaining energy-rate portions by replacing the CAISO day-ahead hourly market price component with the real-time 5-minute price, and replaces the $0.14/kWh base-rate adder with a multiplier on market prices. The intent is to represent marginal generation costs more granularly, and to recover remaining utility costs in a way that increases the incentive to load-shift rather than diluting it.
- Results from initial modeling suggest that the two modeled commercial rates' demand charges tend to encourage load-flattening over load-shifting, and the demand-charge-free VGI rate is more effective at incentivizing GHG emissions reduction. The proposed VGI modifications substantially boost generation-cost and GHG benefits, achieving outcomes similar to those seen when the storage system is directly optimizing against utility marginal costs.

- The noncoincident monthly demand charge for large commercial and industrial customers set as part of the FERC Transmission Owner rate case can potentially run counter to the incentives associated with peak-aligned demand or energy charges in some cases.

- After the workshop, Enel X discovered an incorrect calculation in how daily vs. monthly demand charges were treated for the PG&E B-19S Option S rate. Fixing this calculation has a noticeable impact on what appeared to be the most controversial finding; where previously the storage system increased GHG emissions by about 9 metric tons/year, the revised calculation now shows it reduces GHG emissions by about 0.5 metric tons/year. This result now would still not quite meet the new SGIP GHG requirement, and the perfect-forecast modeling approach used likely underestimates the amount of midday storage discharge for noncoincident demand charge management, so may overestimate GHG reductions. As a result of this correction, utility marginal cost impacts for Option S are also now more in line with AL-TOU and the unmodified VGI. These changes are reflected in Row #2 of Slide #21 of the Attachment B presentation and in the table directly below. Also note a small additional change on Slide #22 of Attachment B, where "$0.14/kW Base Rate" was corrected to "$0.14/kW**h** Base Rate", which is also reflected in the second table shown below.

San Diego Office – Annual Savings Comparison

enel x

Rate	Utility Generation Cost Savings	Utility Distribution Cost Savings	GHG Emissions Reduction
SDG&E AL-TOU (Current)	$1,722	$690	1.0 metric tons/year increase
PG&E B-19S Option S (Final Decision)	$1,938	$665	0.5 metric tons/year decrease
SDG&E VGI (2018 Pilot Rate)	$1,641	$664	3.5 metric tons/year decrease
SDG&E Modified VGI (Proposed Rate)	$12,784	$665	43.1 metric tons/year decrease
Utility Marginal Costs	$10,770	$881	28.6 metric tons/year decrease

Proposed Rate – Modified SDG&E VGI

Original SDG&E VGI Rate	Proposed Modified SDG&E VGI Rate
No Fixed Charges	Fixed charge based on connection voltage and kVA
No Demand Charges	No Demand Charges
CAISO Day-Ahead Hourly Price	CAISO Real-Time 5-Minute Price
$0.14/kWh Base Rate (Subtotal Base Rate + Commodity Base Rate + Distribution Base Rate)	~5x Multiplier on CAISO RT5M Price
$0.51/kWh Commodity CPP Hourly Adder on Top 150 Day-Ahead System Peak Hours	~$0.50/kWh Commodity CPP Adder on Top ~1800 Real-Time System Peak Intervals
$0.51/kWh Distribution CPP Hourly Adder on Top 200 Day-Ahead Circuit Peak Hours	~$0.50/kWh Distribution CPP Adder on Top ~2400 Real-Time Circuit Peak Intervals
No power factor/kVAR charges	Dynamic $/kWh and $/kVARh adders based on circuit loading, voltage at meter (based on Volt-VAR/Volt-Watt curves).

Solar Energy Industries Association ("SEIA")

SEIA's presentation provided its perspective on the demand charge issues that have been debated in recent general rate case (GRC) Phase 2 cases such as this one. SEIA is generally supportive of the Commission's direction over the last decade to reduce the use of demand charges in commercial and industrial (C&I) rates, especially in support of the important policy objectives of reducing greenhouse gas emissions and of sending price signals to customers to shift their loads in ways that are beneficial to the system as a whole. Today, the most valuable loads are not the steady, baseload customers that traditionally have been favored by a rate design based heavily on demand charges that are not time-dependent. Instead, the most valuable customers are ones whose loads can respond flexibly to the increasingly granular, close-to-real-time price signals that can be sent by a modern, time-sensitive rate design coupled with today's communication technologies.

SEIA's presentation highlighted several significant problems with demand charges:

- Noncoincident demand charges, which are based only on a customer's maximum monthly demand in a 15-minute window, without a time element, discourage beneficial load shifts.
- Monthly demand charges do not incent <u>daily</u> actions (such as cycling on-site storage).
- Monthly demand charges increase the risks and costs of customer actions and investments to reduce demand.

SEIA recognizes that, in changing the structure of C&I rates, there can be concerns with "cost shifts." It is first necessary to identify to whom costs could be shifted. Cost shifts, if they occur as the result of a more cost-based rate design, are not necessarily a bad thing. SEIA discussed the experience with residential TOU rates and Option R rates for solar customers, as examples where the Commission found the revised rate to be more cost-based than the old rate. If there are concerns with cost shifts, there are established ways to mitigate those concerns, including:

- tracking revenue changes,
- caps on rate availability, and
- technology-based limits on eligibility.

Cost shifts due to rate design changes also can impact customers who have made long-term investments in clean energy technologies in reliance on the prior rate design. These impacts can be mitigated through gradualism and grandfathering.

Given the imperatives to reduce carbon emissions and to accelerate the adoption of clean energy technologies, experimentation in rate design should be encouraged with Commission oversight, and pilots are one way to gain real world experience.

With respect to the specific issues in this SDG&E Phase 2 case, SEIA expressed concerns related to SDG&E's demand charge studies. These concerns include;

- Many types of T&D projects are linked to peak demand, even if a project's primary reason is not to expand capacity.
- The analyses of marginal distribution costs in GRC Phase 2s show that peak loads drive distribution investments.
- Even fewer T&D investments are linked to individual customers' noncoincident, non-time-related peaks demands than to coincident, system peaks.
- T&D costs not related to demand should be allocated to energy rates (e.g. fire hardening, meeting RPS requirements).

SEIA presented the following chart showing, in the top section, how the Commission allocated 61% of SDG&E distribution costs to peak-related charges (versus non-coincident demand charges that lack a time element) in the last SDG&E Phase 2 case. The bottom section of the chart shows a possible allocation for this case, based on the percentage of SDG&E circuits that peak during the on-peak period, from SDG&E's demand charge study.

As Adopted in D. 17-08-030 (SDG&E's last GRC Phase 2)				
		Marginal Distribution Capacity Costs	Time-related Percentage	Weighted Peak MDCC
		$ per kW-year		*$ per kW-year*
Circuits	$	78.00	50.0%	$ 39.00
Substations	$	22.00	100.0%	$ 22.00
Total	$	100.00		$ 61.00
Percent of total				***61%***

Possible Allocation for A. 19-03-002				
		Marginal Distribution Capacity Costs	On-peak %	Weighted Peak MDCC
		$ per kW-year		*$ per kW-year*
Circuits	$	71.67	67.0%	$ 48.02
Substations	$	19.61	76.8%	$ 15.06
Total	$	91.28		$ 63.08
Percent of total				***69%***

The issues related to demand charges that SEIA may evaluate, discuss, and present a position on in its testimony in this proceeding include:

- Allocation of distribution costs to the following C&I rate design elements:
  - Noncoincident demand charges
  - Time-related demand charges
  - TOU or flat energy rates
- An Option S rate for SDG&E C&I customers who install storage, similar to the Option S rate approved for PG&E. This rate features a daily demand charge.
- Changes to SDG&E's Option R rate (Schedule DG-R). This rate perhaps should evolve to be available to all customers, similar to SCE's Option E rate.
- Recommendation for the Commission's position at FERC on SDG&E transmission rates.

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

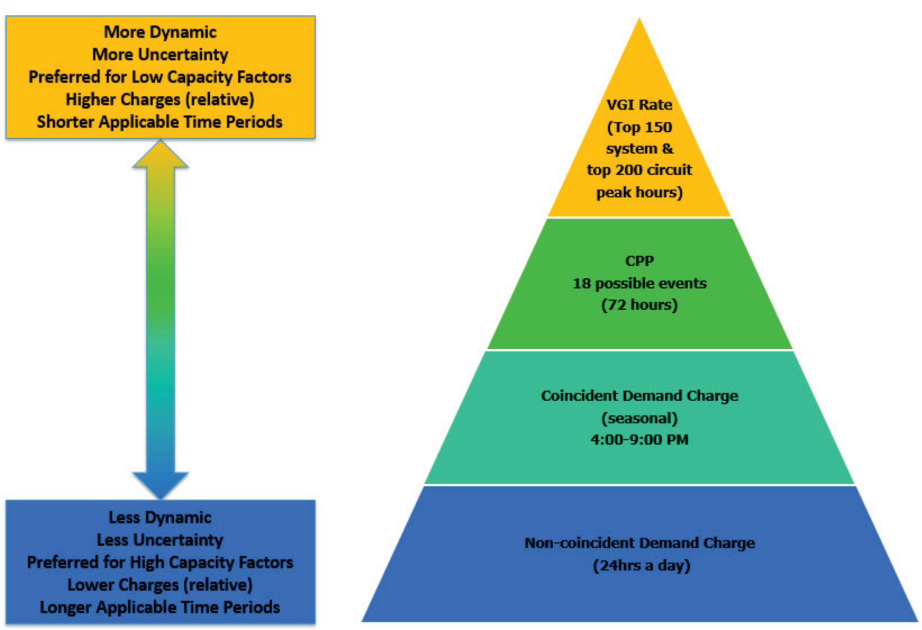
- SDG&E filed and served supplemental information on August 12 to explicitly state whether and how SDG&E's distribution demand charge research study, and/or the results of the alternative scenario, impact its application.
- Portions of the workpapers related to distribution revenue allocation and supporting the Chapter 5 Revised Prepared Direct Testimony of William Saxe reflect the

distribution demand charge study that SDG&E prepared in response to Ordering Paragraph 33 of D.17-08-030.

- SDG&E did not, however, flow through any of the results of its distribution demand charge study into SDG&E's proposed distribution revenue allocations or proposed distribution demand charge rates. This is because SDG&E made the policy determination to propose to maintain the current 39% / 61% split of non-coincident-to-peak demand charge cost allocation that the Commission approved in D.17-08-030.
- SDG&E's electric distribution system is designed to meet non-coincident peak demand (individual customer service requirements). The table below shows that allocating distribution cost entirely to On-Peak or All Other Hours would not adequately address how SDG&E circuits peak throughout the day.

	Circuit - % Peaking	
	On-peak (4pm - 9 pm)	All Other Hours
2014	58.2%	41.8%
2015	59.1%	40.9%
2016	67.0%	33.0%

- Illustrated the following relationships between demand charges / rates, and characteristics of each. Note a correction made during the workshop that "Low Capacity Factors" and "High Capacity Factors" written in the rectangular boxes below, should read, "Low Load Factors" and "High Load Factors".



- Showed that all-volumetric rates may lead to cost shifts and under collections, specifically as it relates to schedule DG-R. Characteristics of schedule DG-R include that it is an optional rate open to C&I customers with distributed generation systems, and its distribution & commodity costs are all volumetric ($/kWh).

Annual Schedule DG-R Cost Shift		
Year	Undercollections ($ millions)	YOY % Increase
2015	$2.4	-
2016	$3.9	65%
2017	$5.4	38%
2018	$6.2	14%
2019	$7.8	26%

Southern California Edison ("SCE")

SCE is committed to its Clean Power and Electrification Pathway as a means of achieving California's GHG emissions goals. As demonstrated in SCE's recent 2018 GRC Phase 2 and 2017 Transportation Electrification proceedings, SCE recognizes that restructuring of legacy rate designs plays a key role in increasing the adoption of new technologies, with related changes in customer behavior, that can lead to lower GHG emissions. A wholesale restructuring of rates, however, can lead to a redistribution of customers who benefit under the new rate structure and those who do not. Without the benefit of a holistic process to evaluate the equity and cost effectiveness of the changes, the resulting rate structures could lead to revenue shifts that are not justified by the level of GHG offset.

As the Commission moves forward with its exploration regarding the appropriateness and level of Non-Coincident Peak (NCP) demand charges, equity across customer classes, cost-effective GHG reductions, and affordability must all weigh prominently in the final consideration. If the resulting NCP demand charge structure results in too large of a revenue shift, the Commission's goals in the specific areas of affordability, Transportation Electrification (TE), and Building Electrification (BE) may become harder to achieve.

Converting legacy NCP demand charges to a Daily Demand Charge (DDC) structure will undoubtedly benefit DER customers. Therefore, the question at hand is not whether the segment can benefit from a DDC structure, but rather at what cost will they benefit. SCE highlighted four of the Bonbright rate design principles[1] in order to place an emphasis on areas of rate design that rank higher on the list of priorities when

[1] EEI Publication, April 2013; Based on "Principles of Public Utility Rates" by James C. Bonbright, 1988.

evaluating the efficacy of daily demand charges. These principles include fairness, efficiency, stability, and simplicity. The principles help illuminate the impact a DDC structure may have on participants and non-participants alike. For example, if through the proceeding the DDC structure is found to be cost-based, would the structure then be applied broadly to all customers, or instead reserved for specific segments as an optional rate? Would the DDC structure be generally acceptable and understandable to customers? Can the utilities implement a DDC at a reasonable cost and timeframe? How would the resulting revenue shift be allocated given approximately 50% of distribution revenues are currently allocated to the residential class even though the DDC would not be applicable to the class? Are there simpler, more cost-effective alternatives? These are just a few of the challenges that would need to be addressed when considering the restructuring of NCP demand charges.

SCE made considerable changes to the NCP demand cost structure in its recent 2018 GRC Phase 2 proceeding, where the Marginal cost determinations recognized the benefits and costs associated with the changing energy landscape, to include new DER technologies. The bi-directional nature of DER technologies, in addition to the time variant nature of distribution circuit loading, formed the basis of the new cost structure and rate design. Revenues previously recovered from a single NCP demand charge are now recovered through two separate rate components. The Grid, or non-time-variant component, recovers fixed costs through an NCP demand charge, while the Peak, or time-dependent component, recovers variable costs through time-variant energy or demand charges.

Comparison of Distribution Revenue Recovery

	TOU-8-SEC, Current B	TOU-8-SEC, Proposed D		TOU-GS-3, Current B	TOU-GS-3, Proposed D
% in Energy	0%	12%	% in Energy	0%	12%
% in TRD	0%	33%	% in TRD	0%	33%
% in FRD	100%	55%	% in FRD	100%	55%
	TOU-8-SEC, Current R	TOU-8-SEC, Proposed E		TOU-GS-3, Current R	TOU-GS-3, Proposed E
% in Energy	17%	70%	% in Energy	50%	70%
% in TRD	0%	0%	% in TRD	0%	0%
% in FRD	83%	30%	% in FRD	50%	30%

Through the 2018 GRC Phase 2 settlement process, Parties agreed to adjust Option D and E rates from the originally proposed levels to reflect the revenue recovery in the table shown above. The resulting rate structures, including limits on participation for customers with demand greater than 500 kW, are believed to strike a reasonable balance between providing a price signal to encourage the use of new energy storage, TE, and BE technologies, while reducing the revenue shift to non-participating customers.

SCE took a similar approach to TE rate design, but also created a limited additional benefit to specifically address extremely low load factor profiles characteristic of the nascent EV market at the time. The additional benefit, a 5-year period of energy only charges with a transition to an Option E like structure over another 5 years, was designed to limit the expected revenue shift while ultimately transitioning to a more cost-based rate that shared a common rate structure with SCE's other options. Limiting the energy charge only period to the earlier years of the adoption curve helped reduce the overall impact of the program on non-participants. The transitioning to a demand charge structure helped customers gradually learn to manage load as their fleets increased. At the end of the transition period, customers landed on a rate option design for DER usage pattern, with no further action on their parts. This transition pathway provides stability and simplicity as the additional benefit is removed from the rate. The TE rate design thus exemplifies the rate design principles outlined earlier in SCE's discussion, which can lead to a cost-effective and affordable means to GHG reduction.

Pacific Gas and Electric ("PG&E")

- PG&E sets its standard distribution rates for its largest customers using a peak demand component and a non-coincident demand component, based on its cost of service studies, and has done so for many years.
- PG&E does not have any specific input to the SDG&E case but notes that design of distribution rates should be based on each utility's cost of service in each utility's Phase II proceeding.
- PG&E agrees that alternatives for distribution rate design, such as those described during the workshop, should be studied and piloted before being implemented on a large scale, to ensure that they have the intended effect, and to minimize the potential for large unintended consequences. In particular, PG&E notes the possibility of unintended consequences from its new storage-only B-19 Option S rate (which was modeled by Enel X as incentivizing a storage dispatch profile that does not quite meet the new SGIP GHG requirement for the case considered).
- PG&E believes that any subsidized benefit that participating customers receive though lower bills should be compared to the value of the benefits to non-participating customers (e.g., GHG benefits) to ensure that the relative cost of any rate program is reasonable.
- The Commission has adopted specialized rates for storage in PG&E's 2017 GRC Phase II. Next steps, for PG&E, will be to implement and study those new rates.

Additional Participant Comments

CPUC Opening Remarks – Commissioner Shiroma

Commissioner Shiroma indicated that the CPUC has a responsibility to align rates, cost causation, affordability, and rate stabilization. While some of these characteristics are rooted in historic preference, factors such as solar may warrant modifications to how demand charges are designed and evaluated going forward.

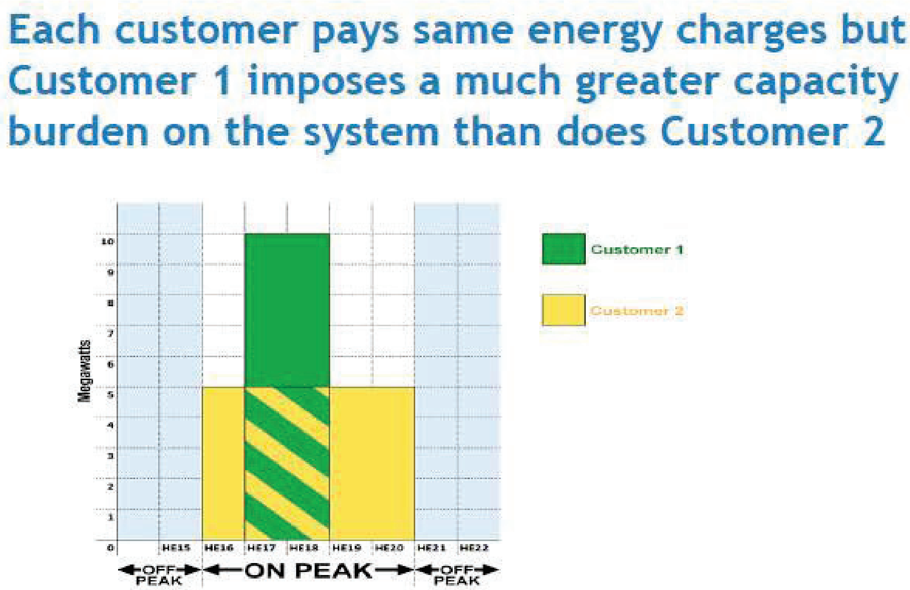
The Utility Reform Network ("TURN")

Storage has the potential to shift load and mitigate the duck curve issue. However, as many pointed out, by modifying demand charges to provide price signals for customers to deploy storage, stakeholders agree that cost shifting to other customers is likely to occur. There is another viable option that doesn't create the cost-shifting issue but still presents the same benefits – utility owned storage. Utility owned storage would be able to shift load, mitigate the duck curve, and pass along the cost savings to all ratepayers.

TURN strongly believes that the proposed mitigations of tracking cost shifts and potentially capping the amount is not sufficient. First, a detailed study of cost savings needs to be conducted (for cost savings to the grid that could result from customers deploying behind-the-meter storage). Second, the subsidy/savings/price signal being provided via a modification of the demand charge cannot exceed the estimated cost savings. Third, the cost savings need to be tracked and deducted from revenue requirements determined in the General Rate Case ("GRC"). This way the Commission can ensure that non-participating customers do not unjustly subsidize participating customers, and that cost savings are passed along to ratepayers.

California Large Energy Consumers Association ("CLECA")

CLECA appreciates the Commission's concern regarding the importance of Green House Gas ("GHG") reduction as a goal for designing rates. CLECA submits, however, that GHG reduction only one of several goals that need to be considered in designing rates for customers. Two other essential goals are cost causation—that rates should reflect the marginal cost burden placed by customers on the system, and equity—that rates should fairly distribute utility revenue requirement among customers. CLECA presented the following chart at the workshop to demonstrate why CLECA believes that eliminating demand charges violates the tenants of cost causation and creates an inherently unfair cost shifting from low load factor customers to high load factor customers.



As CLECA discussed at the workshop, capacity costs are fixed costs, not variable costs. Placing fixed capacity costs in energy rates unfairly shifts costs that are incurred by low load factor customer onto high load factor customers. In this scenario, low load factor customers pay less than their cost to serve and high low factor customers pay more than their cost to serve. Furthermore, increasing energy rates for higher load factor customers beyond what is justified by marginal cost based rate designs could encourage bypass of the utility's system.

CLECA urges the Commission to keep in mind that industrial customers compete in out-of-state and international markets. They cannot just pass higher electricity costs resulting from cost shifts along to their customers. Thus, the level of electricity rates is extremely important to the viability of industrial businesses in California. Electric rates directly affect the State's climate goals, because keeping the production of cement, steel, minerals, industrial gases, and beverages in California enables their manufacture where energy is cleaner and avoids additional emissions associated with transportation from out-of-state facilities. Since California seeks to avoid greenhouse gas leakage in the electric energy sector as part of its climate policy, it should also be concerned about leakage if critical industries move outside California.

If the Commission decides that rates for DER customers should be developed with reduced demand charges, such as the Option E rates on SCE's system, CLECA urges the Commission to direct the utilities to design the rates around the subclass of customers with DER and not the entire class of customers. Designing rates around the DER subclass instead of the entire customer class enables the development of a cost-based DER rate schedule based on the specific load profiles that are associated with the group of customers that will be served by the schedule and the costs to serve them. Allowing non-DER customers to remain on a separate schedule that is designed around their specific load profiles would also help ensure that their rates remain cost-based. Any under-collections associated with each rate schedule would remain with the respective rate schedule, thus ensuring that there is no cost shifting.

California Solar and Storage Association ("CALSSA")

CALSSA rejects CLECA's assertion that low load factor customers impose "a much greater capacity burden on the system." Due to load diversity, one customer's change in demand from one moment to another is smoothed out by thousands, or millions, of other customers' changes in demand. Low load customers' demand profiles may, but do not necessarily, impose higher costs relative to total consumption for lower levels of the distribution system where there is less load diversity.

San Diego Airport Parking ("SDAP")

1) SDAP largely agrees with the Commissions' objectives as characterized by SEIA, especially: "2: [Reflecting] Cost causation principles in ratemaking" and "3: Reducing greenhouse gas emissions"

2) SDAP largely agrees with SEIA that current SDG&E demand charges have significant "problems" and therefore do not correctly reflect cost causation.

3) Circuit peak loading when can't be managed requires advanced technology such as battery storage as an option.
Load Shifting should be supported for peak time use to optimize grid use, reduce demand, and reduce emissions. Reduced rates and demand charges during daytime reduced emission hours create the best price signals for integrating battery storage hubs for peak time use.

4) Use of power with storage shifts best case solutions for grid use with equipment and technology that creates load and thereby can avoid adding distribution cost.

5) We need a 21st century demand rate design.

6) SDG&E is the only IOU with peak demand in all of its Large Commercial Tariffs.

7) Suggest creating a Baseline for Demand on large commercial customers that own 15% of the load on a circuit. Customers whose load comprises less than 15% of the load on any distribution circuit should be exempt from distribution demand charges. Distribution costs (other than fixed charges) should be recovered from such customers only in volumetric TOU rates.

8) SDAP reserves the ***right to make*** further ***changes and to supplement the foregoing.***

Next Steps

All parties may file and serve comments regarding the August 27, 2019 workshop and in response to SDG&E's workshop report. Parties that file comments regarding the August 27, 2019 workshop are directed to identify the specific questions that would need to be addressed, and/or the specific data/information that would be needed, in order for the Commission to consider (1) changes to SDG&E's proposed split between non-coincident demand charges and coincident (or peak) demand charges, (2) changing rates that have monthly demand charges to rates with daily demand charges, and/or (3) any other demand charge-related proposals that any intervenor intends to include in its testimony. Party comments regarding the August 27, 2019 workshop shall be due no later than September 26, 2019.

Reference

The webcast recording is accessible at the following url:
http://www.adminmonitor.com/ca/cpuc/workshop/20190827/.

ATTACHMENT B

SDG&E GRC Phase 2 Demand Charge Alternatives Comparison

2019-08-27

Need for Load Shift Resources

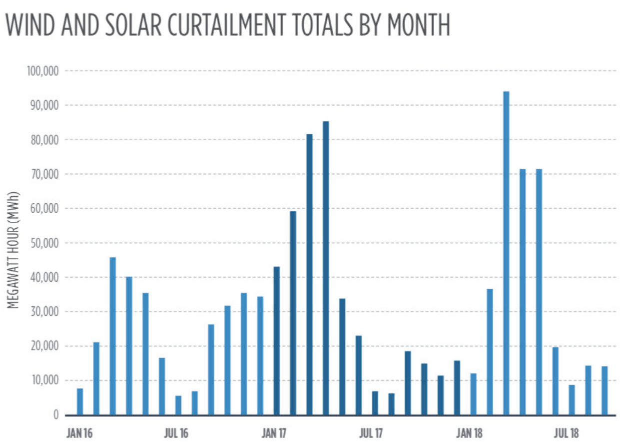


FIGURE 2. *California Wind and Solar Monthly Curtailments*

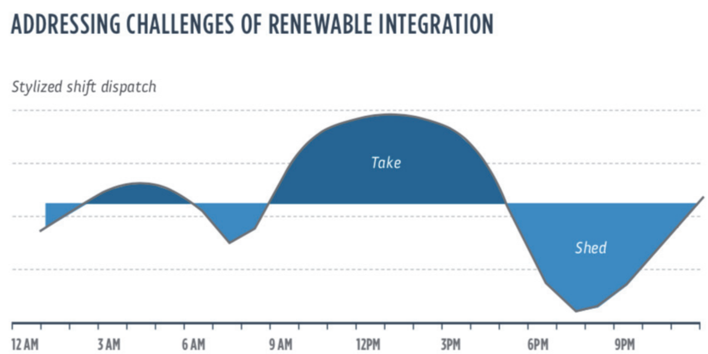


FIGURE 3. *Targeted Load Shift*

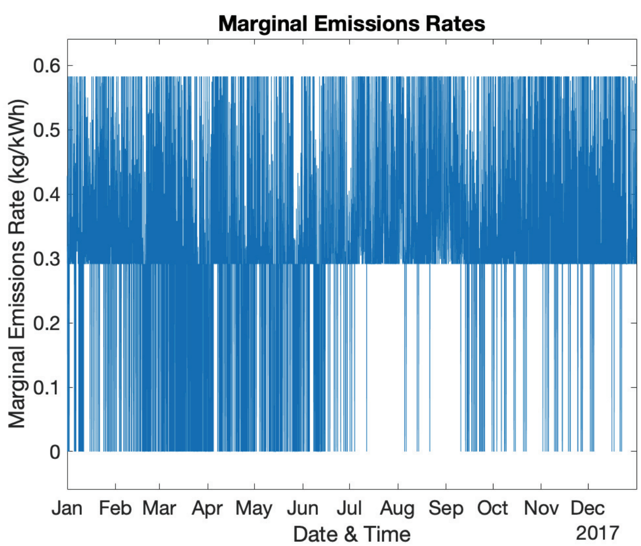
Source: LBNL for the Load Shift Working Group

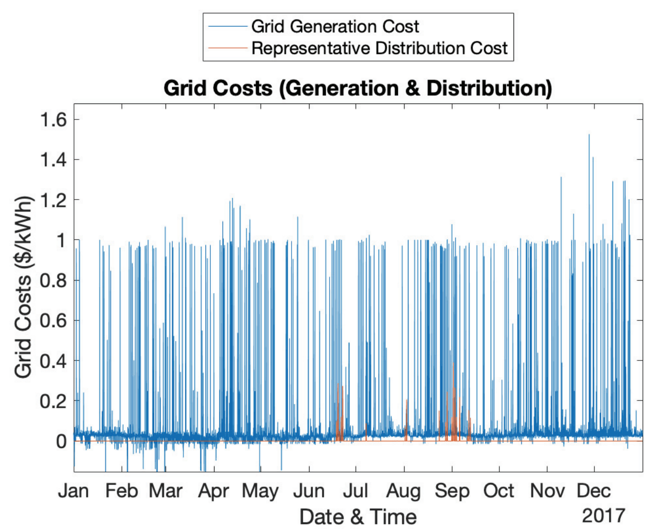
Source: Load Shift Working Group Final Report

Modeling Input Values

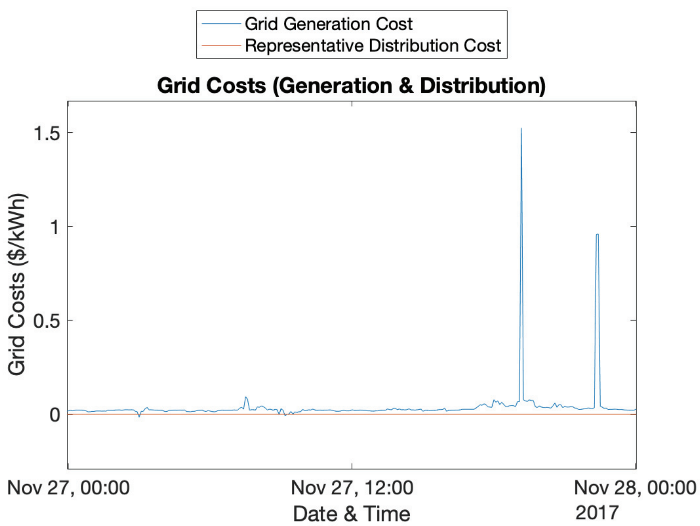
- Energy Storage Dispatch Model:
  - Open-Source Energy Storage Model (OSESMO) from SGIP GHG Technical Working Group
- Storage-Only: 200 kW x 400 kWh
- Load Profile: EnerNOC San Diego Office (from EnerNOC Open Data 2012)
- Utility Marginal Cost Data: 2017 SP15 RT5M LMP + PG&E Mission Feeder Distribution Cost
- GHG Data: 2017 CAISO SP15 (SGIP Implied-Heat-Rate Methodology)
- Rates:
  - SDG&E AL-TOU (Current)
  - PG&E B-19S Option S (Final Decision)
  - SDG&E VGI (2018 Pilot EV Rate)
  - Modified SDG&E VGI (Proposed Rate)
  - Utility Marginal Costs ("Gold Standard" Benchmark)

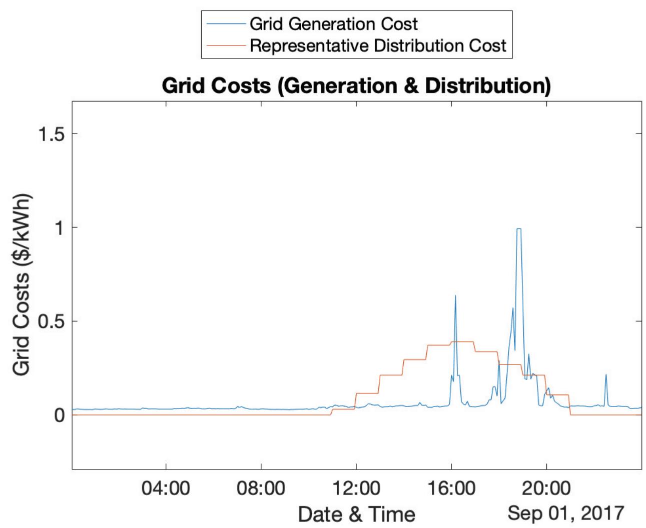
GHG Emissions Rates & Utility Marginal Costs



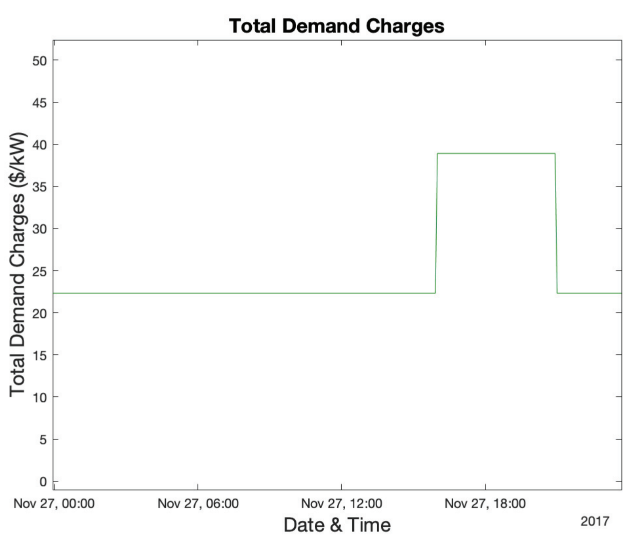


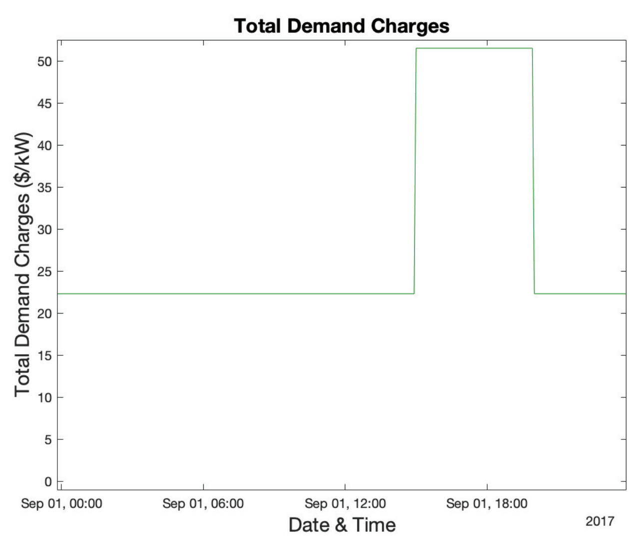
Utility Marginal Costs – Peak Days



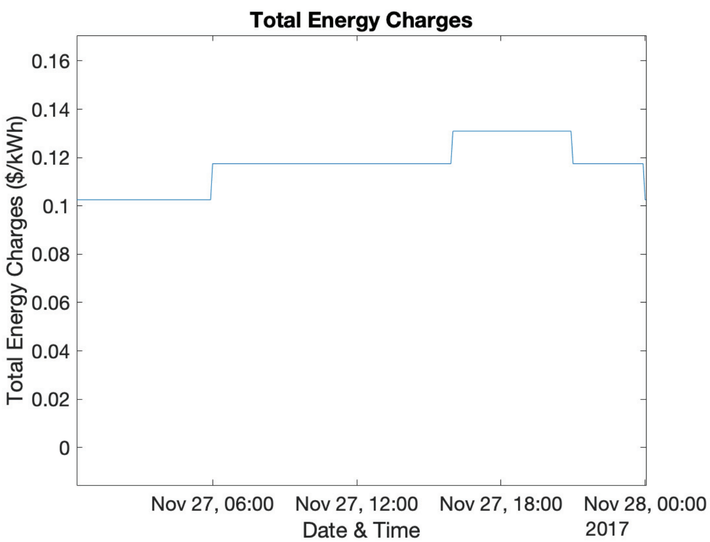


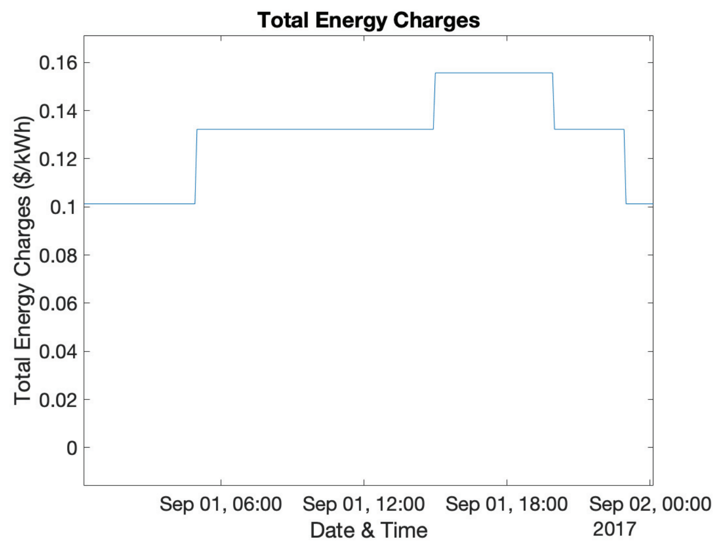
SDG&E AL-TOU – Demand Charges



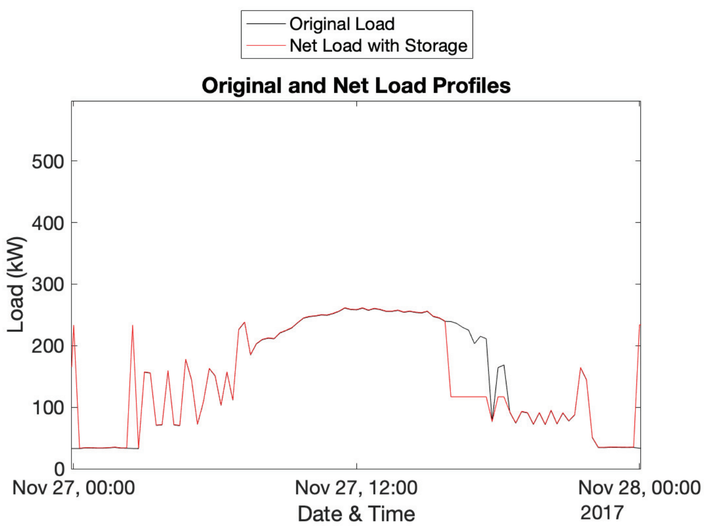


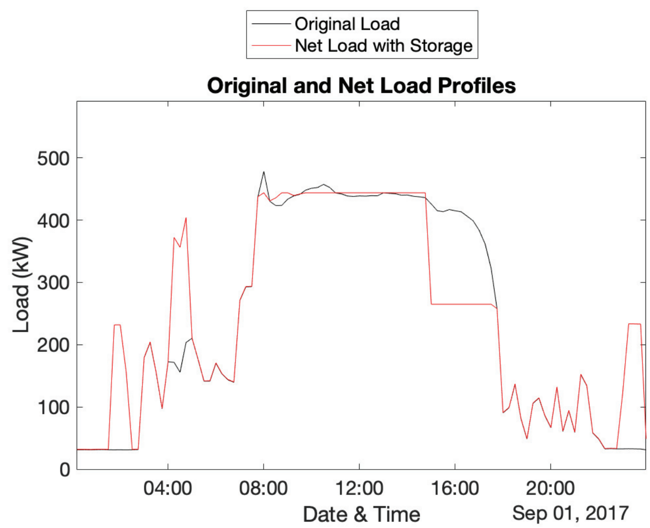
SDG&E AL-TOU – Energy Charges



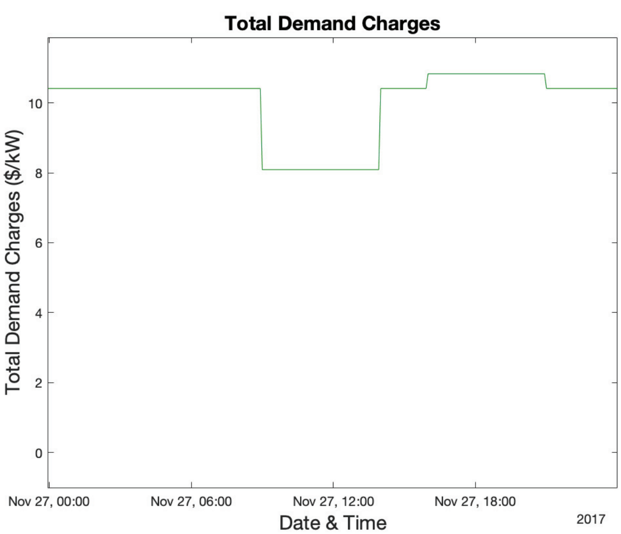


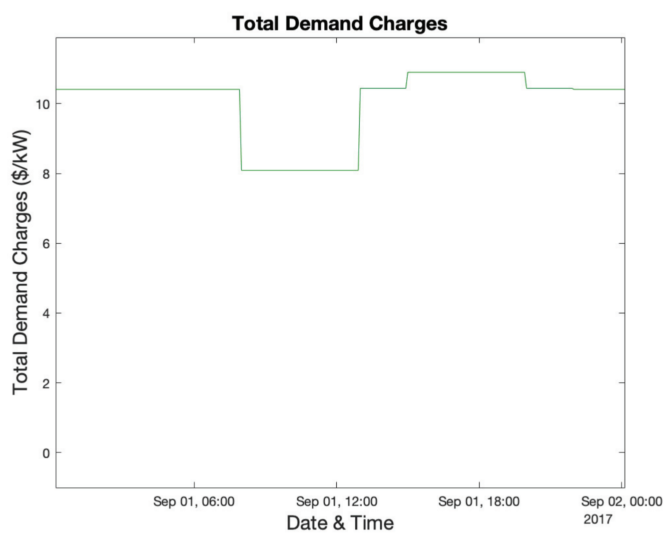
SDG&E AL-TOU – Storage Dispatch





PG&E B-19S Option S – Demand Charges





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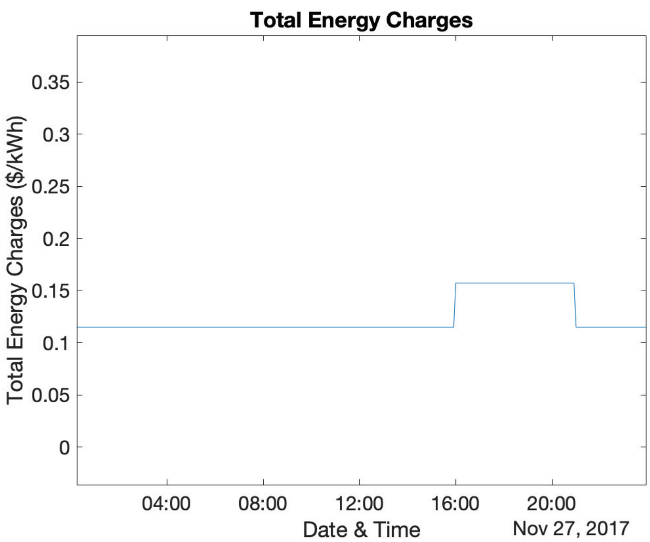

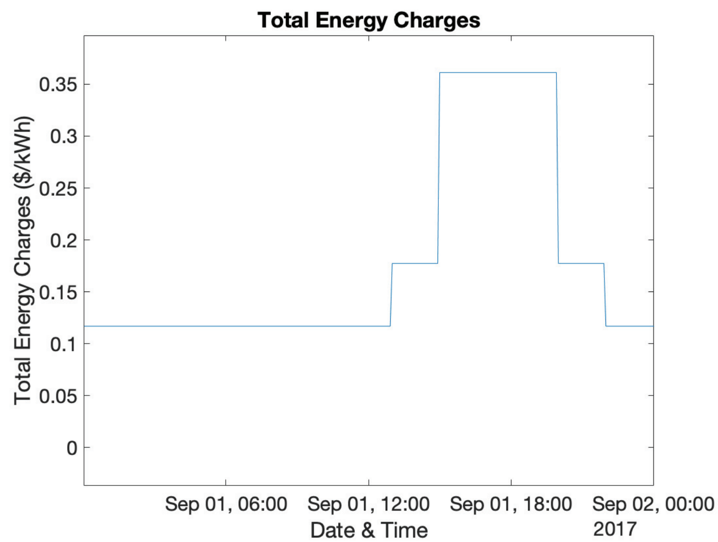

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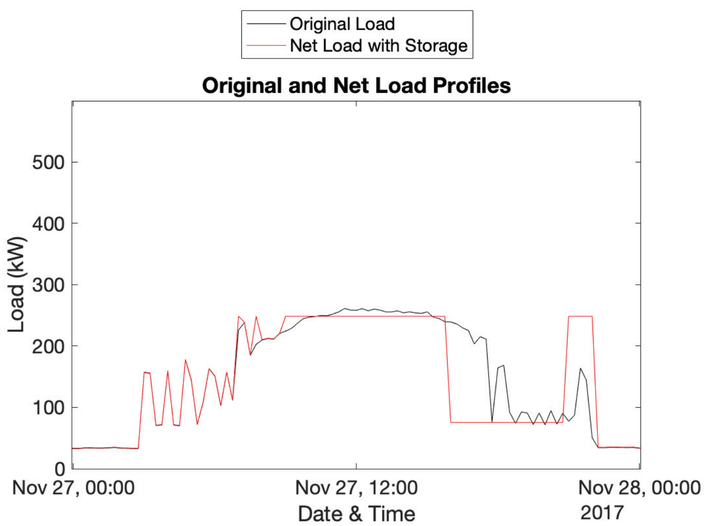
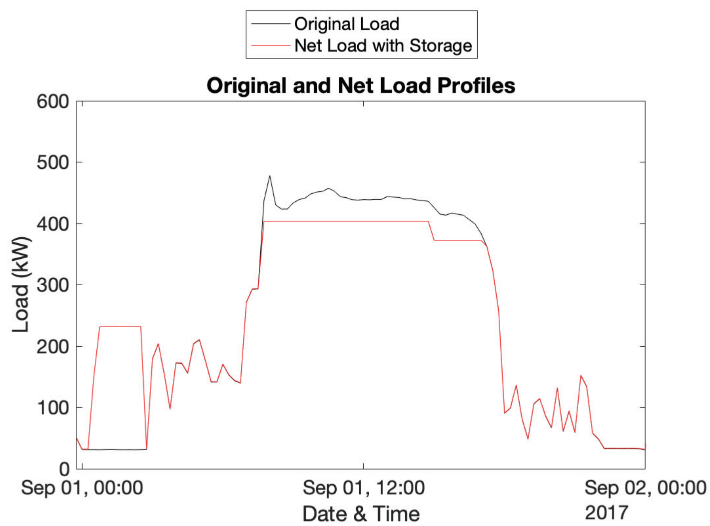
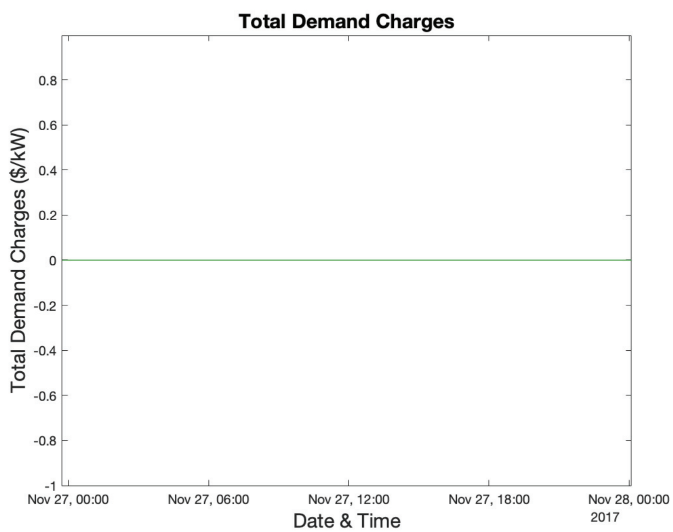
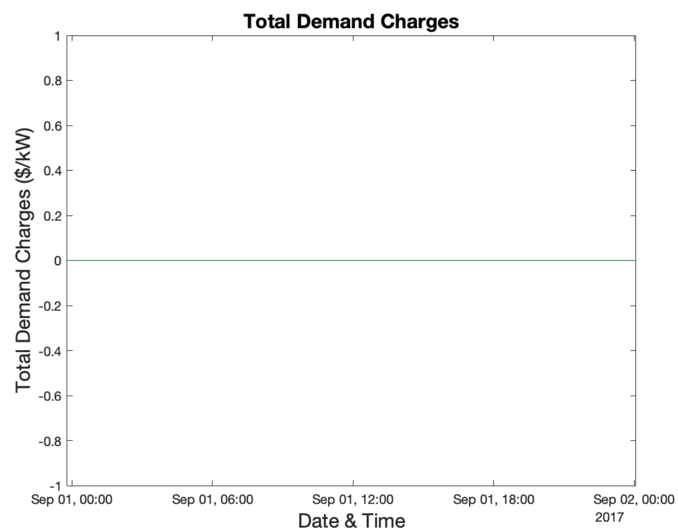


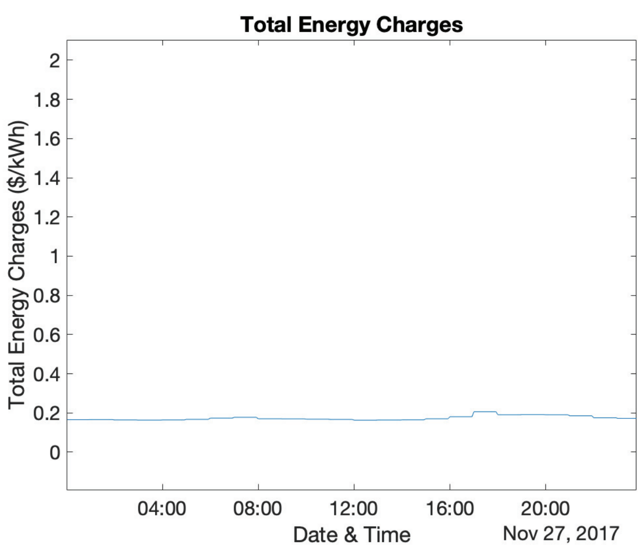


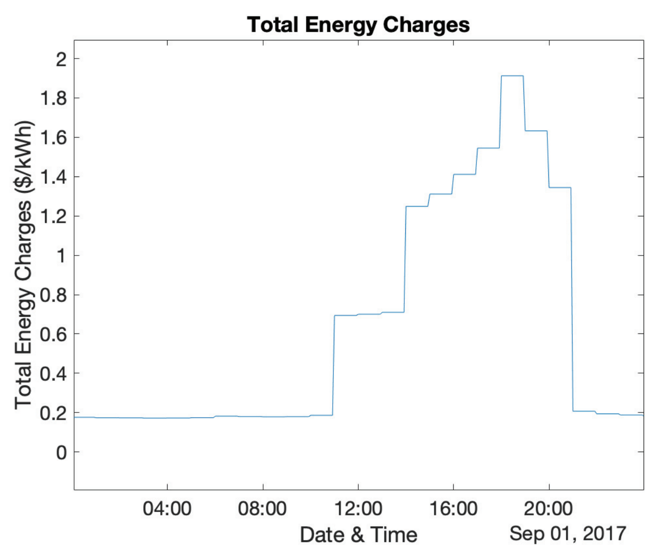
SDG&E VGI – Demand Charges



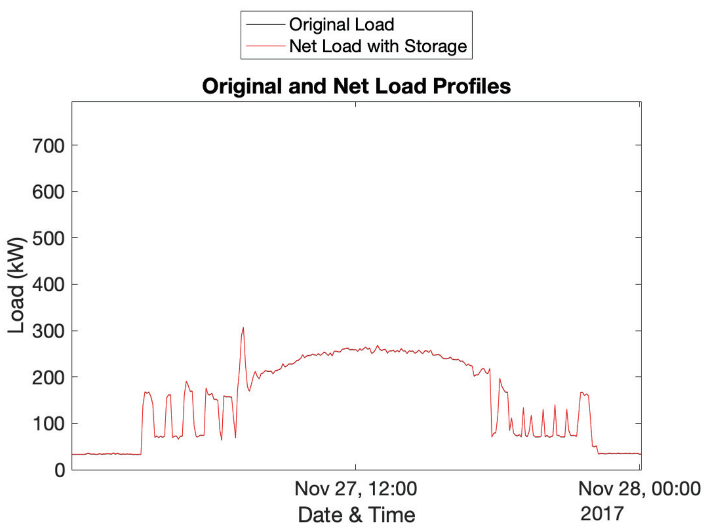


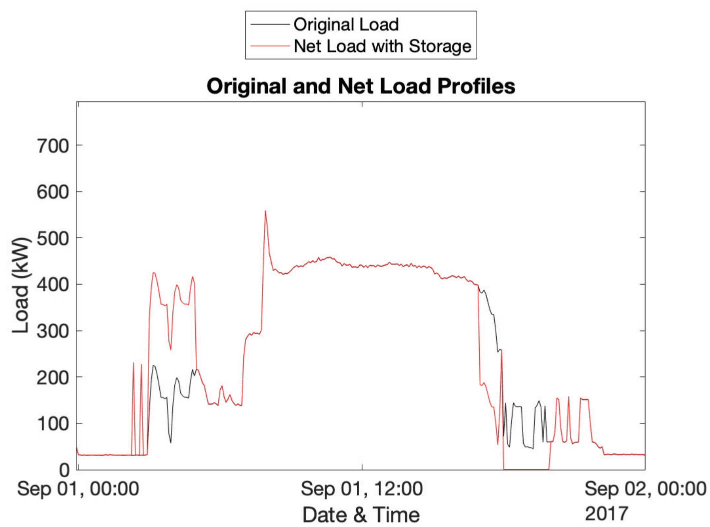
SDG&E VGI – Energy Charges



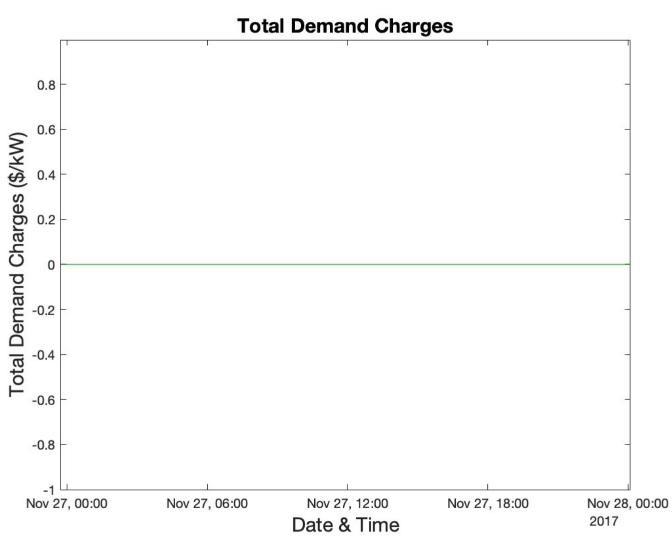


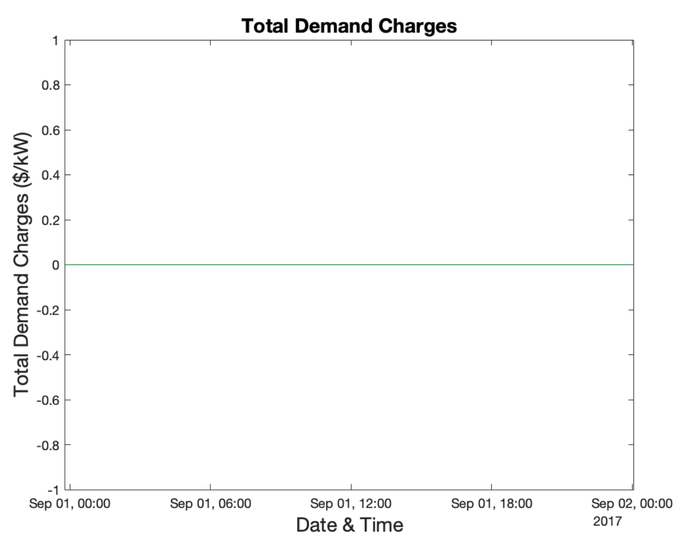
SDG&E VGI – Storage Dispatch



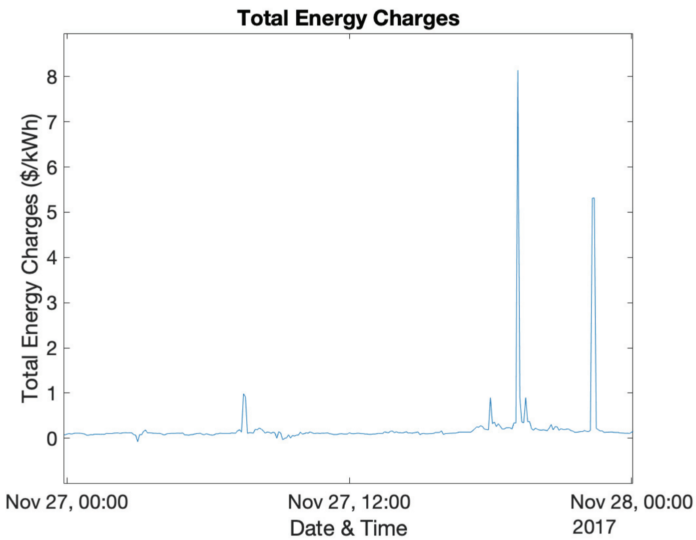


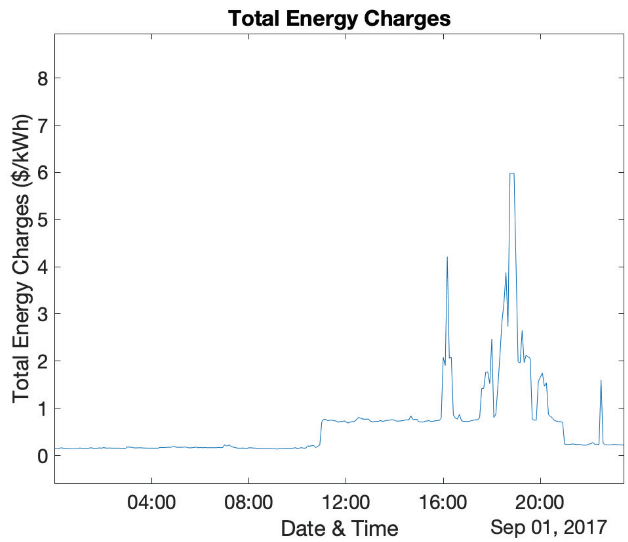
SDG&E Modified VGI – Demand Charges





SDG&E Modified VGI – Energy Charges





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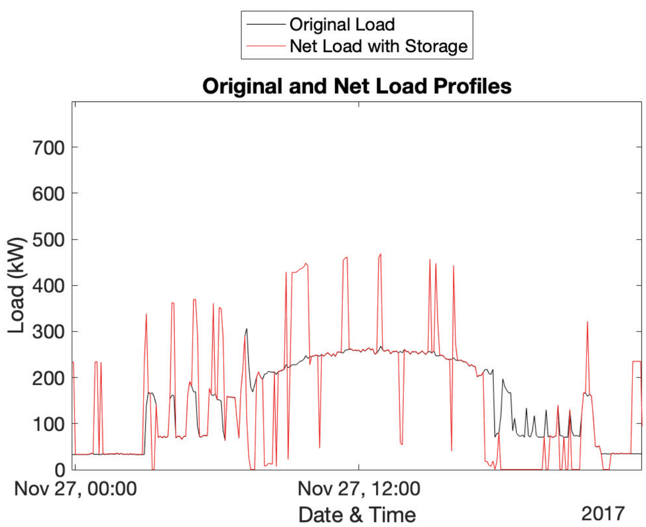
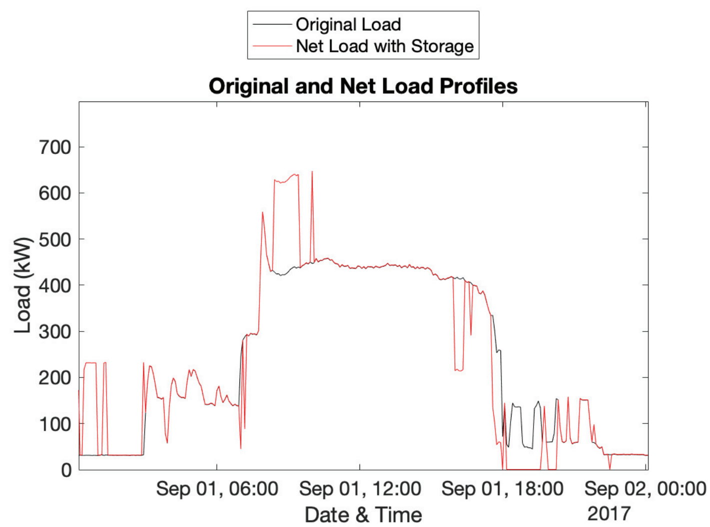
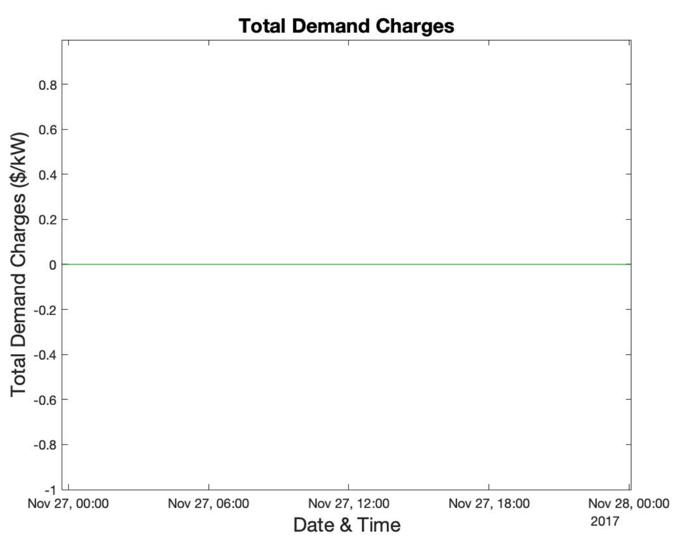
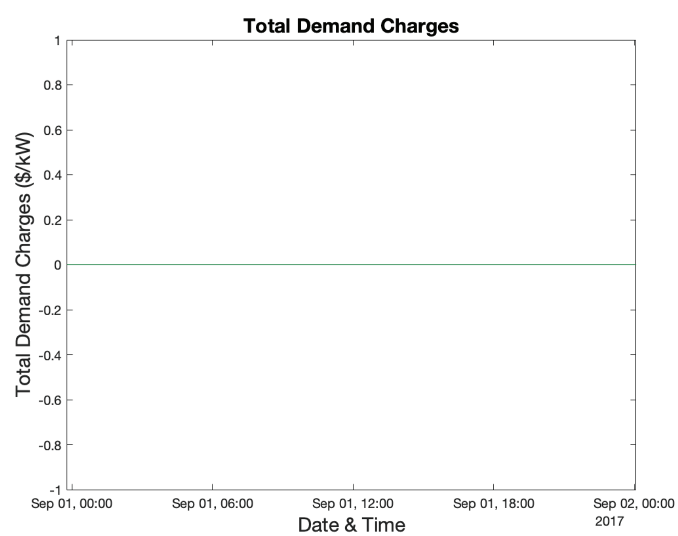


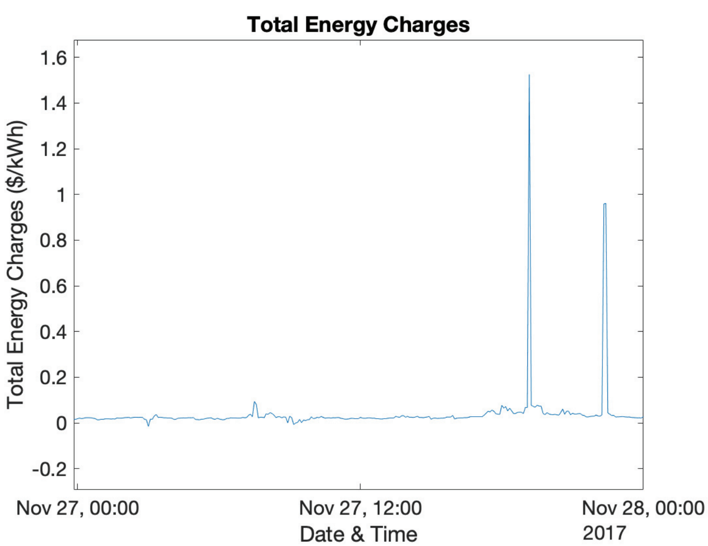


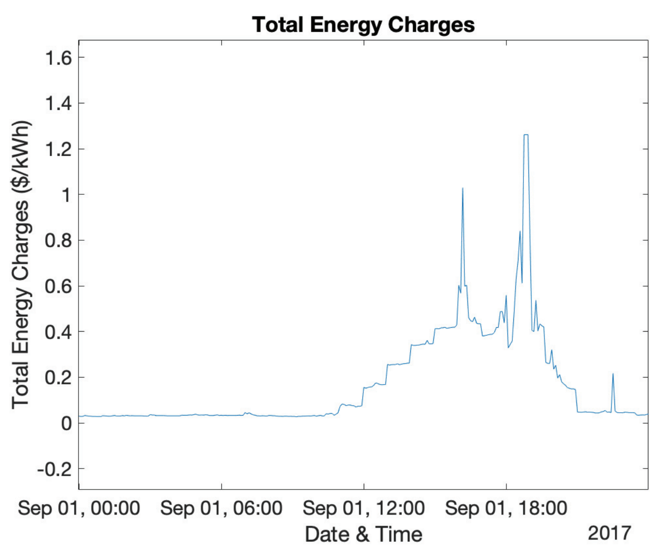
Utility Marginal Costs – Demand Charges



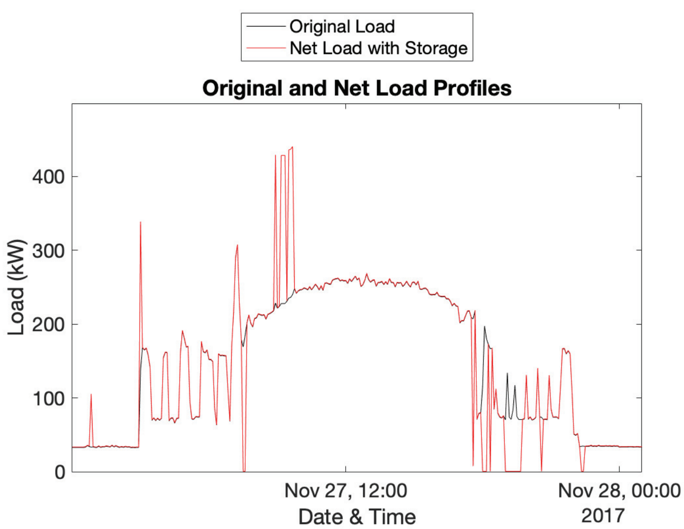


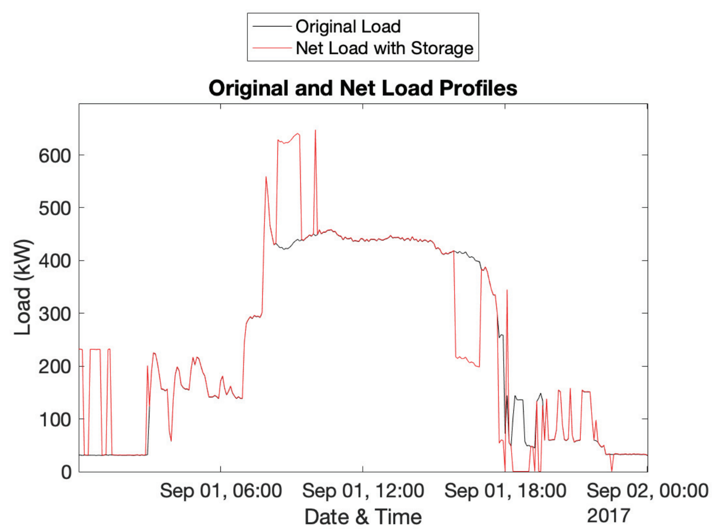
Utility Marginal Costs – Energy Charges





Utility Marginal Costs – Storage Dispatch





San Diego Office – Annual Savings Comparison

enel x

Rate	Utility Generation Cost Savings	Utility Distribution Cost Savings	GHG Emissions Reduction
SDG&E AL-TOU (Current)	$1,722	$690	1.0 metric tons/year increase
PG&E B-19S Option S (Final Decision)	$1,938	$665	0.5 metric tons/year decrease
SDG&E VGI (2018 Pilot Rate)	$1,641	$664	3.5 metric tons/year decrease
SDG&E Modified VGI (Proposed Rate)	$12,784	$665	43.1 metric tons/year decrease
Utility Marginal Costs	$10,770	$881	28.6 metric tons/year decrease

Proposed Rate – Modified SDG&E VGI

Original SDG&E VGI Rate	Proposed Modified SDG&E VGI Rate
No Fixed Charges	Fixed charge based on connection voltage and kVA
No Demand Charges	No Demand Charges
CAISO Day-Ahead Hourly Price	CAISO Real-Time 5-Minute Price
$0.14/kWh Base Rate (Subtotal Base Rate + Commodity Base Rate + Distribution Base Rate)	~5x Multiplier on CAISO RT5M Price
$0.51/kWh Commodity CPP Hourly Adder on Top 150 Day-Ahead System Peak Hours	~$0.50/kWh Commodity CPP Adder on Top ~1800 Real-Time System Peak Intervals
$0.51/kWh Distribution CPP Hourly Adder on Top 200 Day-Ahead Circuit Peak Hours	~$0.50/kWh Distribution CPP Adder on Top ~2400 Real-Time Circuit Peak Intervals
No power factor/kVAR charges	Dynamic $/kWh and $/kVARh adders based on circuit loading, voltage at meter (based on Volt-VAR/Volt-Watt curves).

ATTACHMENT C

SEIA's Perspective on Alternatives to Traditional Demand Charges

Tom Beach, Principal, Crossborder Energy

Consultant to SEIA

August 27, 2019

About SEIA

- The Solar Energy Industries Association (SEIA®) is the driving force behind solar energy and is building a strong solar industry to power America through advocacy and education. As the national trade association of the U.S. solar energy industry, which now employs more than 250,000 Americans, we represent all organizations that promote, manufacture, install and support the development of solar energy. SEIA works with its 1,000 member companies to build jobs and diversity, champion the use of cost-competitive solar in America, remove market barriers and educate the public on the benefits of solar energy.

Commission Objectives

1. Peak load shifting and other grid support objectives
2. Cost causation principles in rate making
3. Reducing greenhouse gas emissions
4. Ensuring appropriate utility cost recovery
5. Enabling demand-side load management solutions

Objectives #2 and #4 are traditional rate design goals.

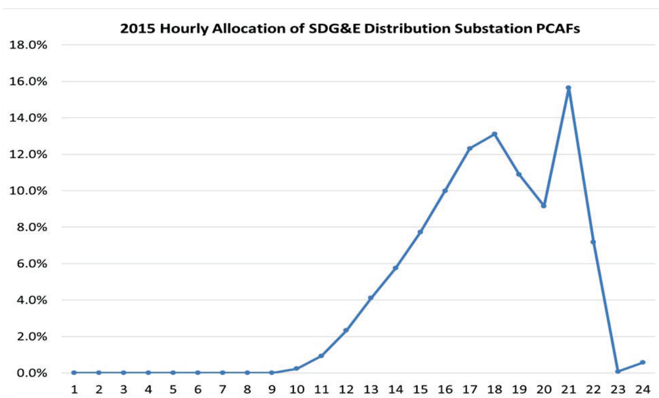
The others reflect today’s circumstances.

Then and Now

- What is the same…
  - The cost of electricity is time-dependent.
- What has changed…
  - Metering: monthly kWh/max kW to 15-minute TOU data
    - Rates are designed based on what can be measured.
  - Generation: baseload fossil / nuclear to time-varying renewables
    - Non-coincident demand charges strongly favor baseload customers.
    - An imperative to use time-varying clean energy efficiently
    - Today's most valuable loads are flexible ones.
  - One-way monthly bill to two-way, near-real-time communications
    - Enables dynamic, more complex rates
  - In a word – data
    - Better data on the temporal and geographic diversity of loads

The Problems with Demand Charges, Part 1

- Noncoincident, non-time-dependent demand charges
  - We have data on the time-dependent loads that drive distribution substation and circuit costs.



  - Demand charges based only on customer max demands, without a time element, discourage beneficial load shifts.

The Problems with Demand Charges, Part 2

- Coincident, peak-related demand charges
  - Do consider the time element.
  - But may not best reflect load diversity….
    - TOU volumetric rates reduce average demand across the peak.
  - … or cost causation
    - Solar customers incur demand charges on cloudy, low-demand days.
  - A monthly demand charge does not incent daily actions.
    - Option S daily demand charge for storage cycling.
  - Monthly demand charges increase the risks and costs of customer actions and investments to reduce demand.

Evolution in SCE's C&I Rates

- Option A (circa 2005)
  - Generation demand charges replaced by volumetric TOU rates.
  - Optional rate available to all customers < 500 kW
  - TOU-8 Option A for permanent load shift technologies
- Option R (2008) – similar to SDG&E's DG-R (2007)
  - Option A plus reduced delivery demand charges
  - Solar customers only
- Option E (2018) – replaces Options A and R
  - Reduced noncoincident and peak demand charges
  - 4p-9p peak
  - Available to all customers (except 250 MW DER cap for TOU-8)
- Option S (soon?) -- promotes daily storage cycling

Cost Shifts (to non-participating ratepayers)

- Utility shareholders are protected by revenue decoupling.
- Concern is cost shifts from multiple, optional rates (self-selection)
- Important factors to consider:
  - Is the new rate option more cost-based?
    - TOU rates
    - Option R for solar customers
  - Does the new rate support beneficial technologies or behaviors?
    - Option S for daily storage cycling
- Ways to mitigate cost shift concerns:
  - Tracking revenue changes
  - Caps on rate availability
  - Technology-based limits on eligibility
- We need to experiment, with active Commission oversight.

Cost Shifts (to participating ratepayers)

- Rates are changing rapidly (e.g. the TOU shift)
- Customers' long-term investments rely on stable rates.
- Ways to mitigate cost shift concerns:
  - Gradualism
  - Grandfathering
- SEIA appreciates the Commission's and the utilities' sensitivity to this issue.

SDG&E Demand Charge Studies

- Studies: small fractions of T&D costs are peak-related.
  - 35% for CAISO transmission
  - 5% for distribution
- Concerns:
  - Many types of T&D projects are linked to peak demand, even if a project's primary reason is not to expand capacity.
  - Marginal distribution costs show peak loads drive investments.
  - Even fewer T&D investments are linked to individual customers' noncoincident, non-time-related peak demands.
  - T&D costs not related to demand should be allocated to energy rates (e.g. fire hardening, meeting RPS requirements).

Peak-related Allocation of SDG&E Distribution Costs

As Adopted in D. 17-08-030 (SDG&E's last GRC Phase 2)			
	Marginal Distribution Capacity Costs	Time-related Percentage	Weighted Peak MDCC
	$ per kW-year		*$ per kW-year*
Circuits	$ 78.00	50.0%	$ 39.00
Substations	$ 22.00	100.0%	$ 22.00
Total	$ 100.00		$ 61.00
Percent of total			***61%***

Possible Allocation for A. 19-03-002			
	Marginal Distribution Capacity Costs	On-peak %	Weighted Peak MDCC
	$ per kW-year		*$ per kW-year*
Circuits	$ 71.67	67.0%	$ 48.02
Substations	$ 19.61	76.8%	$ 15.06
Total	$ 91.28		$ 63.08
Percent of total			***69%***

SDG&E Demand Charge Issues for SEIA

- Allocation of distribution costs
  - Noncoincident demand charges
  - Time-related demand charges
  - TOU or flat energy rates
- Option S
- Changes to Option R
- Recommendation for the Commission's position at FERC on SDG&E transmission rates

ATTACHMENT D

SDG&E GRC Phase 2
Demand Charge Workshop

August 27, 2019

How is SDG&E's distribution demand charge study used in the application?

- SDG&E filed and served supplemental information on August 12 to explicitly state whether and how SDG&E's distribution demand charge research study, and/or the results of the alternative scenario, impact its application.
- Portions of the workpapers related to distribution revenue allocation and supporting the Chapter 5 Revised Prepared Direct Testimony of William Saxe reflect the distribution demand charge study that SDG&E prepared in response to Ordering Paragraph 33 of D.17-08-030.
- SDG&E did not, however, flow through any of the results of its distribution demand charge study into SDG&E's proposed distribution revenue allocations or proposed distribution demand charge rates. This is because SDG&E made the policy determination to propose to maintain the current 39% / 61% split of non-coincident-to-peak demand charge cost allocation that the Commission approved in D.17-08-030.

Table 1: Comparison of Distribution Demand Charge Study Allocations

Allocation	Non-Coincident Demand	Peak Demand
Current (from SDG&E 2016 GRC Phase 2)[5] and Proposed (for 2019 GRC Phase 2)[6]	39.0%	61.0%
SDG&E Results Presented in its Distribution Demand Charge Study[7] and its Ch. 5 Workpapers[8]	94.8%	5.2%
Results of Alternative Analysis Per Resolution E-4951[9]	42.1%	57.9%
Results of Alternative Scenario from May 23, 2019 workshop (using prior TOU Periods)[10]	60.5%	39.5%

Footnotes in Table 1 correspond to the August 12 filing.

Rate Design Principles (R.12-09-013)

SDGE
A Sempra Energy utility®

Cost Of Service RDP	Affordable Electricity RDP	Conservation RDP	Customer Acceptance RDP
(2) Rates should be based on marginal cost; (3) Rates should be based on cost-causation principles; (7) Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals; (8) Incentives should be explicit and transparent; (9) Rates should encourage economically efficient decision-making.	(1) Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost.	(4) Rates should encourage conservation and energy efficiency; (5) Rates should encourage reduction of both coincident and non-coincident peak demand.	(6) Rates should be stable and understandable and provide customer choice; (10) Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

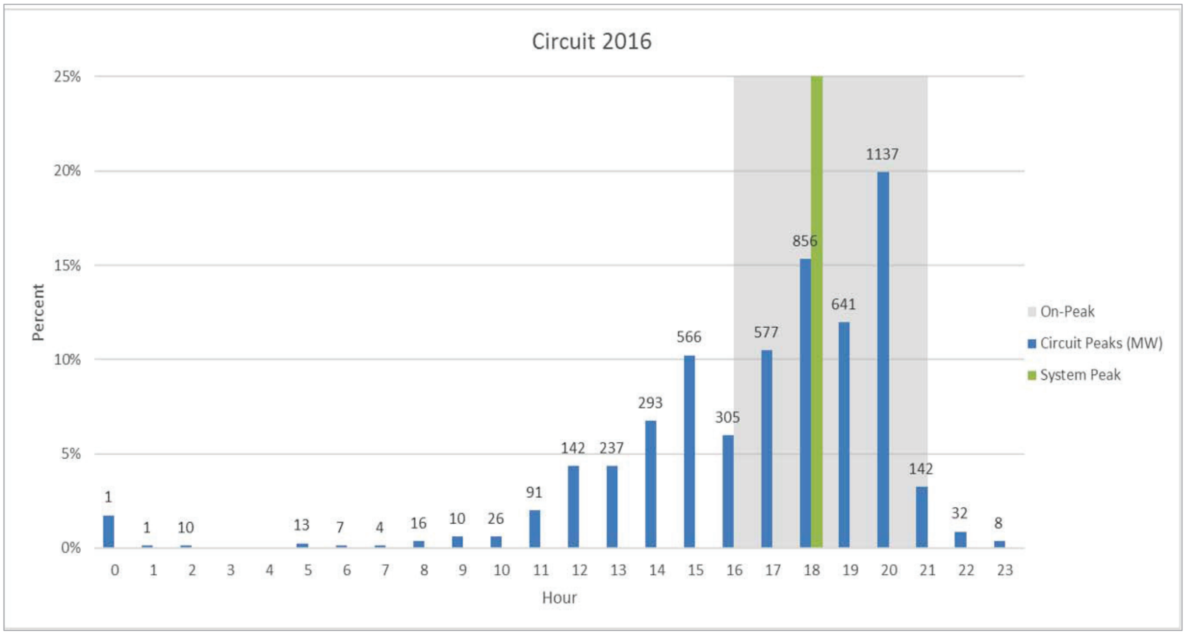
Cost-Based Rate Design

- Customer Costs (billing, call center, meters, service drops, transformers)
  - SDG&E incurs these costs on a fixed basis for each interconnected customer whether or not the customer uses electricity; therefore, customer costs should be recovered in a fixed or monthly charge ($/month).
- Distribution Demand Costs (poles, wires, substations)
  - SDG&E incurs these costs independent of volumetric energy usage. These costs are incurred based on local capacity needs to meet the combined maximum demand of customers served by a given circuit. These costs are best recovered through non-coincident (NCD) demand or coincident (peak) demand charges ($/NCD–kW or $/peak-kW).
- Generation Capacity Costs (cost of adding kWs to the system)
  - SDG&E incurs these costs to meet net peak capacity needs of the system. These costs are not incurred on the basis of volumetric energy usage. Therefore, system capacity costs should be recovered in a demand charge consistent with the time period in which those costs occur, which is demand at the time of net system peak when SDG&E may require additional capacity ($/peak-kW).
- Commodity Energy Costs
  - SDG&E incurs these costs on a variable basis (based on volumetric energy usage) and the cost depends on the time of delivery. Therefore, these costs should be recovered in a volumetric energy charge ($/kWh) that varies by time period.

Distribution System

- SDG&E's electric distribution system designed to meet non-coincident peak demand (individual customer service requirements)
  - Circuits, substations, and transformers peak at different times
  - Distribution assets (substation, transformer, circuit) are designed to meet peak demand for a specific location
  - Industry standard distribution planning process

Example of SDG&E Circuit Peaks (Time Period)

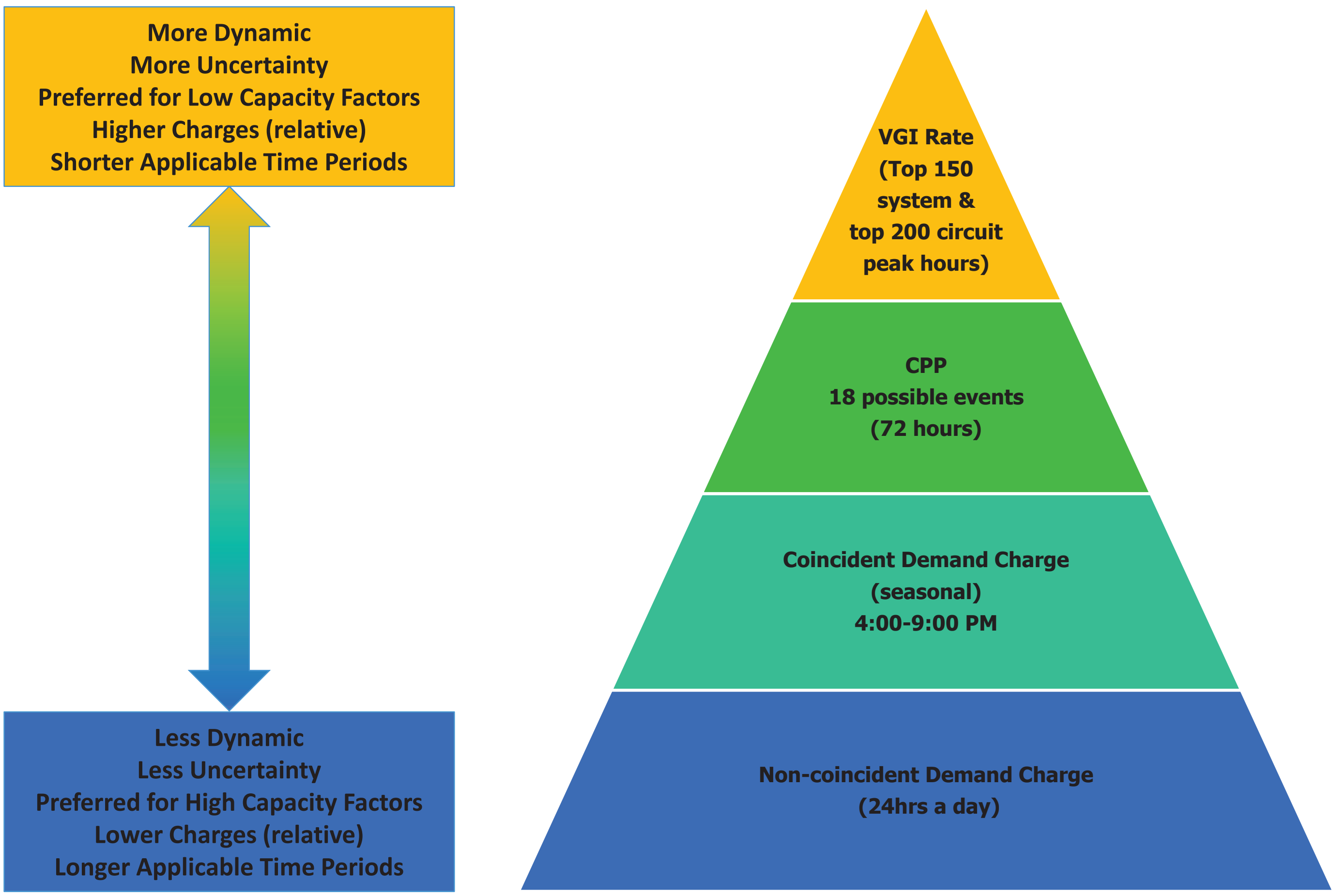


	Circuit - % Peaking	
	On-peak (4pm - 9 pm)	**All Other Hours**
2014	58.2%	41.8%
2015	59.1%	40.9%
2016	67.0%	33.0%

Generation System

- SDG&E's electric generation system is designed to meet system net load peak demand.
  - Net Load reflects electricity demand net of electricity supply from solar and wind resources.
    - Need is greatest in evening when renewables are not as readily available.
  - Demand charges applicable during standard on-peak TOU period (4:00PM-9:00PM)
    - Encourages customers to consistently shift demand from these high-cost hours.
- Critical Peak Pricing (CPP) rates are current default rates for Small Commercial, M/L C&I, and Agricultural customers with demands of 200 kW or greater.

How SDG&E's demand/dynamic charges are applied



All-volumetric rates may lead to cost shifts & undercollections

- **SDG&E Schedule DG-R**
  - Optional: open to C&I customers with distributed generation systems
  - Distribution & Commodity costs all $/kWh volumetric TOU vs. default schedule with demand charges
  - Undercollections are tracked annually (compare what was paid to what these customers would have paid on their otherwise default rate schedule)
  - Any undercollections are shifted to the whole M/L C&I class
  - In 2018, 310 customers (553 accounts) on Schedule DG-R

Annual Schedule DG-R Cost Shift		
Year	Undercollections ($ millions)	YOY % Increase
2015	$2.4	-
2016	$3.9	65%
2017	$5.4	38%
2018	$6.2	14%
2019	$7.8	26%

ATTACHMENT E

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

Treatment of Demand Charge Rate Designs at SCE

Presenter
Robert Thomas – Manager of Pricing Design

Rate Restructuring Requires a Balanced Approach

- SCE is committed to its Clean Power and Electrification Pathway as a means of achieving California's Greenhouse Gas (GHG) reduction goals
  - A review and restructuring of legacy rate designs is a key element in achieving these goals

- Restructuring rates inevitably leads to redistribution of revenue recovery due to:
  - Redefined cost basis (cost drivers)
  - Reordering of structural benefiters
  - Introduction of public policy driven rate designs

- GHG reductions should be achieved through a cost effective approach that also considers the impacts in such areas as:
  - Affordability
  - Building electrification
  - Non-participant equity

Principles of Rate Design

"Rates should provide clear, efficient, effective, informative, and cost effective market signals... should allow the utilities to serve as an agent of progress."

1. Fairness
   - Fairly apportion the cost of service among different customers (rates reflect cost causation)
   - Avoid regressive rate structures/policies that favor participants over non-participants
2. Efficiency
   - Promote the efficient use of energy (and competing products and services)
   - Support economic efficiency – set prices to reflect marginal costs
3. Stability
   - Minimize unexpected rate changes that may be adverse to existing customers
   - Ensure revenues (and cash flow) are stable from year-to-year
4. Simplicity, understandability, public acceptability, and feasibility of application

SOURCE: EEI Publication, April 2013; Based on "Principles of Public Utility Rates" by James C. Bonbright, 1988

Recent Changes to SCE's Legacy Rate Structures
- 2018 GRC Phase 2

- SCE's 2018 General Rate Case (GRC) Phase 2 modified the legacy non-coincident peak (NCP) demand charge
  - Distribution costs recovered through NCP demand charge include incremental capacity, reliability, and O&M spending associated with distribution grid infrastructure
  - Customer marginal costs are recovered through fixed charges and consist of meter, service drop, and final line transformer

- 2018 GRC Phase 2 rates reflect new system conditions and facilitate the integration of Distribution Energy Resources (DERs)
  - Two part Grid and Peak distribution cost recovery structure
    - Grid components facilitate bi-directional flow of energy expected with DER applications
      - Ensure appropriate cost recovery for cost components that are not time- or peak- dependent
    - Time-dependent Peak component is associated with capacity growth and a pricing signal to reduce peak load conditions

SCE 2024 Forecast Average Hourly Peak Component of Distribution Design Demand Marginal Costs ($/kWh)*

Weekdays

Columns: Hour Ending (PPT)
Rows: Months

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.002	0.001	0.001	0.001	0.001	0.003	0.007	0.006	0.006	0.005	0.003	0.002	0.003	0.003	0.004	0.006	0.006	0.024	0.018	0.015	0.010	0.007	0.008	0.005
February	0.002	0.001	0.001	0.001	0.001	0.002	0.006	0.007	0.006	0.005	0.004	0.004	0.004	0.005	0.004	0.005	0.006	0.014	0.015	0.013	0.008	0.007	0.007	0.005
March	0.002	0.000	0.001	0.001	0.000	0.002	0.005	0.005	0.004	0.002	0.003	0.002	0.002	0.002	0.003	0.004	0.006	0.008	0.010	0.010	0.010	0.008	0.006	0.004
April	0.002	0.001	0.001	0.001	0.001	0.001	0.004	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.006	0.011	0.008	0.010	0.009	0.009	0.007	0.005
May	0.004	0.001	0.001	0.001	0.001	0.001	0.003	0.003	0.003	0.002	0.002	0.003	0.003	0.003	0.004	0.006	0.009	0.020	0.013	0.015	0.016	0.012	0.008	0.006
June	0.005	0.002	0.001	0.001	0.002	0.001	0.002	0.003	0.003	0.005	0.004	0.006	0.004	0.008	0.010	0.016	0.020	0.028	0.020	0.021	0.022	0.021	0.017	0.010
July	0.009	0.005	0.003	0.002	0.003	0.004	0.007	0.007	0.009	0.009	0.012	0.013	0.012	0.019	0.025	0.029	0.043	0.088	0.060	0.043	0.036	0.032	0.024	0.015
August	0.011	0.005	0.003	0.003	0.003	0.006	0.009	0.008	0.009	0.011	0.013	0.014	0.016	0.024	0.031	0.049	0.071	0.095	0.065	0.047	0.040	0.032	0.025	0.017
September	0.007	0.003	0.002	0.002	0.002	0.004	0.010	0.008	0.008	0.009	0.010	0.011	0.015	0.019	0.026	0.040	0.059	0.101	0.044	0.046	0.036	0.025	0.021	0.015
October	0.003	0.001	0.000	0.001	0.001	0.003	0.005	0.005	0.005	0.004	0.004	0.004	0.003	0.006	0.008	0.015	0.022	0.039	0.024	0.030	0.017	0.011	0.008	0.006
November	0.002	0.001	0.001	0.001	0.001	0.002	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.006	0.006	0.009	0.045	0.024	0.014	0.009	0.007	0.007	0.005
December	0.003	0.001	0.001	0.001	0.001	0.003	0.006	0.006	0.006	0.005	0.004	0.004	0.003	0.004	0.005	0.006	0.007	0.041	0.025	0.019	0.013	0.009	0.008	0.006

Weekends and Holidays

Columns: Hour Ending (PPT)
Rows: Months

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.005	0.005	0.005	0.004	0.003	0.002	0.001
February	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.004	0.006	0.005	0.004	0.002	0.002	0.001
March	0.002	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.004	0.003	0.002	0.002	0.002
April	0.002	0.001	0.001	0.000	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.002	0.002	0.002	0.003	0.003	0.002	0.002
May	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.003	0.002	0.003	0.005	0.004	0.003	0.001
June	0.004	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.000	0.001	0.000	0.001	0.002	0.003	0.003	0.010	0.011	0.009	0.009	0.010	0.008	0.004
July	0.005	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.003	0.005	0.008	0.019	0.018	0.015	0.016	0.013	0.012	0.005
August	0.008	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.002	0.002	0.003	0.003	0.006	0.011	0.017	0.051	0.054	0.024	0.025	0.020	0.012	0.007
September	0.006	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.003	0.004	0.007	0.021	0.030	0.076	0.050	0.049	0.027	0.020	0.010	0.006
October	0.004	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.002	0.001	0.001	0.001	0.001	0.002	0.004	0.011	0.008	0.012	0.006	0.004	0.003	0.001
November	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.003	0.010	0.006	0.005	0.002	0.003	0.002	0.001
December	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.002	0.014	0.006	0.006	0.004	0.003	0.003	0.002

* Illustrative example

DER Rates Introduced in SCE's 2018 GRC Phase 2

- SCE's 2018 GRC Phase 2 introduced Option E (a DER technology rate)
  - Option E further reduced the amount of revenue recovered through NCP demand charges
  - Provides a rate choice to recognize changing customer preferences

- Strikes a balance between:
  - Customer choice
  - Safeguards against revenue shifts
  - Cost causation in rate design
  - Equity across customer segments

- Revenues recovered through NCP demand charge are associated with the provision of bi-directional access of the grid
  - Time variant energy and demand charges to recover revenues associated with peak capacity

Distribution Revenue Recovery Comparison

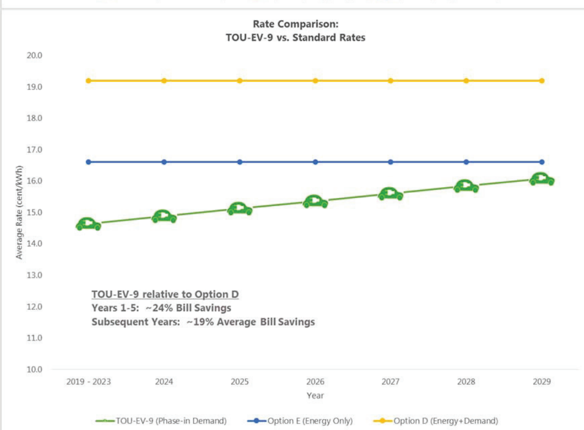
[redacted]		
	TOU-GS-3, Current B	TOU-GS-3, Proposed D
% in Energy	0%	12%
% in TRD	0%	33%
% in FRD	100%	55%
	TOU-GS-3, Current R	TOU-GS-3, Proposed E
% in Energy	50%	70%
% in TRD	0%	0%
% in FRD	50%	30%
[redacted]		
	TOU-8-SEC, Current B	TOU-8-SEC, Proposed D
% in Energy	0%	12%
% in TRD	0%	33%
% in FRD	100%	55%
	TOU-8-SEC, Current R	TOU-8-SEC, Proposed E
% in Energy	17%	70%
% in TRD	0%	0%
% in FRD	83%	30%
[redacted]		

Recent Changes to SCE's Legacy Rate Structure
- Transportation Electrification (TE) Charging Rates

- Demand charge rate structures can result in higher average rates for low load factor early adopters
  - Introduced a 5-year energy only introductory period
  - Followed by a 5-year phase-in of demand charges
  - End state TE rate structures envisioned to be consistent with Option E rate structure
- Load Management Plays a Key Role in Overall Benefit
  - Gradually phasing in demand charges will allow customers to gain knowledge and experience regarding demand charges and load management – still high on the Loading Order
- Rate Simplicity and Customer Understandability
  - Rate design that does not require radical billing system changes
  - Rate design that accommodates customer transitions from discounted to regular rate structure without disruption
- Rate equity provided by the transitory reduction in the policy driven benefit
  - Demand charges gradually phased in to reflect the segment's contribution to grid costs

Average Rate Comparison

- Illustrative TOU-EV-8/-9 vs. Standard Rates



TE Rate Findings

- TE bill comparison is based on the current population, a vast majority served on this rate are DC fast charging customers
- Compared to Standard **Option E**, TOU-EV-8 provides about a **30% bill savings in the 5-year introductory period w/o demand charges**, followed by an average bill savings of 17% in the subsequent years of the program.
- Compared to Standard **Option D**, TOU-EV-9 provides about a **24% bill savings in the 5-year introductory period w/o demand charges**, followed by an average bill savings of 19% in the subsequent years of the program.
- Preliminary results with the daily demand charge rate indicate similar or greater differences to Options D & E

Preliminary Daily Demand Charge Rate

- The Daily Demand Charge Option converts the NCP demand charge to a daily demand charge
  - Retains time variant demand and energy charges associated with peak capacity
- Further analysis is needed to determine if the revenue shift constitutes a cost shift given bi-directional DERs use the grid even when providing electricity to the grid

Conclusion

- SCE has made considerable changes in NCP demand cost determination and rate design recognizing the benefits and costs associated with the changing energy landscape and new DER technologies
  - Cost basis for the new rate structure must consider the bi-directional nature of DER technologies

- Equity across customer segments and affordability must be considered when introducing non-legacy rate structures
  - Introduction of a newly structured cost based rate can redistribute revenue recovery across customer segments
  - Has the potential to create division between those who can afford the new technologies and those who cannot

- Rate simplicity from a customer perspective and a billing system implementation perspective are critical to the successful adoption of non-legacy rate structures

ATTACHMENT F

SDG&E GRC Phase II Demand Charge Workshop
August 27, 2019

PG&E
Distribution Demand Charges and Options

Dan Pease and Jan Grygier

Together, Building
a Better California

Distribution Capacity Cost and Rate Design

- Distribution capacity costs are derived on a $/kW basis where the distribution system must be sized to meet demand. Accordingly, rates that are well aligned with costs recover these capacity costs on a $/kW basis.
- Rate design is dictated by each utility's cost of service
- At PG&E, a portion of capacity costs are peak-related and a portion are based on load that is non-coincident, which allows rates for a portion of distribution capacity costs to be time differentiated.
- PG&E's fully cost based rates for distribution capacity consist of peak demand charges and non-coincident demand charges (e.g. E-19/20).

  - Non-coincident demand charges are applied to the peak demand in the month.

  - Coincident demand charges are typically applied to the peak demand in the peak and part-peak TOU periods, where rates are higher in the peak period.

Alternatives to Traditional Demand Charges (1)

The Commission has approved a number of alternative ways to collect distribution capacity cost.

- For Option R, TOU demand charges were converted to TOU energy rates for customers with solar.

2017 GRC Phase II resulted in several alternative designs for customers with storage:

- Medium and Large C&I Option S for Storage: Distribution demand charges fully converted to alternative charges.
  - TOU daily demand charges (applicable in peak and part peak periods)
  - Special non-coincident demand charge; applies all hours except 9 am to 2 pm.
  - Approved subject to participation caps.
  - Requires future study to account for cost shifts, impact on GHG emissions as well as avoided payments for embedded cost.

Alternatives to Traditional Demand Charges (2)

2017 GRC Phase II (cont)

- Small Commercial Schedule A1-Store, for customers with storage, includes a non-coincident demand charge that is applied only during the hours of 2 pm to 11 pm (peak and partial peak periods). Participation capped.
- Residential Schedule EV2, adapted for storage, distribution capacity costs recovered in energy rates. Participation capped.

PG&E has proposed EV charging rates for C&I customers:

- Subscription charge that recovers >80% of distribution cost.
- Small relative to maximum demand charge $2-4/ kW.
- Separately designed for large and small customers.
- Generally applied based on connected load.

Other designs:

- Ex-post demand charges based on top 5-20 hours of system load.
- Demand charges applied over an average of the highest demand hours in a month rather than the single highest demand in a month.

Considerations for Design Alternatives

Changes to demand charge structures should be carefully considered, changes may be optional or mandatory:

- Optional rates, as are generally available today, present the problem of revenue shortfall from benefitting customers (self selection).

  - Revenue shortfall that is not commensurate with cost reduction results in subsidies that must be supported by other customers.

  - If revenue reductions exceed cost reductions, the Commission should consider what level of subsidy is appropriate in exchange for the benefits all customers receive (e.g., reductions of GHGs).

  - Subsidies may be retained within the class or be supported by all customers.

- If mandatory (applied to all customers) customer understanding and acceptance will be of concern.
- Response of load to various design alternatives (and thus, impact on grid and GHGs) may be counter-intuitive.

  - New alternatives should be capped, or approved as pilots, to limit potential unintended consequences.