Demand Flexibility Tariff Proposal

Microgrid Resources Coalition

Introduction and Summary

1. Introduction

The Assigned Commissioner's Phase 1 Scoping Memo and Ruling (**Scoping Ruling**) in Rulemaking 22-07-005 (**Demand Flexibility Proceeding**)[1] calls for development of joint party proposals to address the issues allocated to each working group established in the Scoping Ruling. The Micrgrid Resources Coalition (**MRC**)[2] proposal (the **Proposal**)[3] addresses the issues in the Track B Working Group 1 relating to demand flexibility design for a demand flexibility tariff. It also provides suggestions on certain related questions assigned to the Track A Working Group and Track B Working Group Phase 2 where issues relating to implementation of a demand flexibility tariff strongly affect the effectiveness of the Proposal.

As envisioned in both the CalFUSE and MRC proposals, a demand flexibility tariff (a **Demand Flex Tariff**) has the potential to integrate behind-the-meter DER and smart non-generation resources, including storage, smart appliances, energy management systems (**EMS**) and EV charging, (**Customer Resources**) into the grid. It provides local, marginal cost prices for demand response (**DR**)[4] and energy export from Customer Resources. This allows Customers to respond to price signals rather than dispatch instructions and receive payments or bill credits for altering their load shape to benefit the grid. Responsive customer action protects the grid by reducing congestion on the transmission and distribution system so that they operate safely within their physical limits.[5]

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[1] Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates, R.22-07-005 (November 2, 2022).

[2] Members of the MRC include: Bloom Energy, City of Lancaster (CA), eco(n)law, ENGIE North America, Google, Icetec Energy Services, Mainspring Energy, Power Storage Solutions, Princeton University, Reimagine Power, Scale Microgrid Solutions, Schneider Electric, and The Energy Coalition. The MRC's comments represent the perspective of the coalition and should not be construed as speaking for individual members.

[3] This proposal was prepared by Baird Brown, eco(n)law LLC, with assistance from Kay Aikin, Dynamic Grid, and Daniel Howard, Reimagine Power.

[4] We are using demand response as a generic term to refer to customer demand reduction down to as low as zero imports in response to the price signal provided by the Demand Flex Tariff. No reference to the terms of other tariffs, such as advance commitments, is intended.

[5] Safdarian, Amir, Mahmud Fotuhi-Firuzabad, and Matti Lehtonen. "Benefits of demand response on operation of distribution networks: A case study." *IEEE systems journal* 10.1 (2014): 189-197.

A Demand Flex Tariff can reduce costs for *all* customers in several ways:[6]

- By shaping load around the availability of intermittent resources, it reduces both peak demand and ramping requirements and allows flexible resources to operate more nearly at resource peak efficiency.
- By managing the system load curve at all times, not only peak times, it provides increased beneficial electrification capacity through better infrastructure utilization and avoids up to $50 billion in distribution infrastructure investments[7]
- By reducing stress on generation, transmission, and distribution equipment it reduces operation and maintenance cost.
- By using lower cost Customer Resources, by avoiding line losses, and by avoiding use of the highest priced peaking resources it reduces systemwide energy price.

The MRC strongly favors implementation of a Demand Flex Tariff. We complement the Energy Division staff on their comprehensive analysis of the issues set out in the Staff White Paper issued at the commencement of this proceeding,[8] and we agree with many of the concepts and elements (collectively, the **CalFUSE Proposal**) set out in the Staff White Paper.[9] Our proposal described below, diverges from the CalFUSE Proposal in three significant ways:

- We propose the use of an option (the **Option**) as a customer risk mitigation tool, rather than a subscription. This avoids customers paying for energy they don't use.
- We propose a variable price based entirely on congestion constrained energy prices, including the CAISO wholesale price[10] combined with a distribution congestion adjustment reflecting congestion on the distribution system (together, the **Variable Energy Price**). This avoids utilities paying rates that are substantially higher (or lower) than for other resources and that distort the wholesale market.
- We propose a pricing structure that will incentivize efficiency and lowered consumption during all hours when they benefit the grid, not just peak hours. This will allow all

[6] Mansouri, Seyed Amir, et al. "A multi-stage joint planning and operation model for energy hubs considering integrated demand response programs." *International Journal of Electrical Power & Energy Systems* 140 (2022): 108103.

[7] *Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates*, Prepared for: California Public Utilities Commission, Energy Division Proceeding R.21-06 017, Kevala Inc.

[8] *Advanced Strategies for Demand Flexibility Management and Customer DER Compensation,* Energy Division White Paper and Staff Proposal (June 22, 2022), (the **Staff White Paper**).

[9] In discussing the CalFUSE proposal we are not singling out the staff proposal, but the range of proposals provided by participants in Working Group 1 that are variations on the same theme.

[10] References to the wholesale price refer to day-of, not day-ahead prices. We are not specifying hourly, 15-minute or 5-minute. This choice can be made on implementation, although shorter intervals are more protective of the grid.

Customer Resources to compete as equals with other resources in supplying the needs of the grid.

- We propose pricing that is entirely based on market-based price formation.

Both the subscription, as included in the CalFUSE Proposal, and our proposed Option rely on a customer load profile based on historic customer usage (the **Customer Profile**). Customer energy purchases up to the Customer Profile are paid for at a flat traditional tariff (the **Legacy Tariff**). This mitigates customer risk from variable prices, which apply only to variations from the profile. The subscription, however, requires the customer to pay for the full amount of the subscription whether the customer uses kWh below the Customer Profile level or not. The Option, by contrast, only requires customers to pay for what they use. The subscription acts as a full requirement fixed charge that eliminates most incentives to invest in energy efficiency. Moreover, as discussed in examples below, the obligation to pay for hours of consumption that the customer doesn't use electricity distorts the intended incentive of the variable price. The Option avoids these distorted incentives. The interaction of the subscription with the variable price also makes it unlikely that the collective effect is revenue neutral.

The CalFUSE Proposal creates a variable price based not only on system marginal energy cost, but also on "marginal capacity costs" which are long run marginal costs. It allocates these elements to a few high grid stress hours, rather than providing a market-rate price signal that remains consistent. This pricing is inconsistent with the price paid to other resources and makes it more difficult to integrate other LSEs and aggregations into the demand flexibility regime. Taken as a whole, the CalFUSE Proposal seems to be designed to produce an overwhelming response on a small proportion of days, with the potential to substantially raise costs for other customers, and no response on other days when it could benefit other customers. The MRC proposal, by comparison, is intended to encourage market participation by Customer Resources as equals with other resources whenever participation is beneficial for the grid. Our proposal reflects our longstanding support for open access markets with fair prices for services both to and from the grid.[11]

The balance of Part 1 provides a summary of our proposal and a numerical example that compares the operation of our proposal to the operation of the CalFUSE proposal. Parts 2 and 3 respond to the questions posed in the Scoping Ruling for the Phase 1 Track B working group. Part 4 looks ahead to implementation questions posed for Phase 2 and to other necessary reforms required to effectively implement a Demand Flex Tariff.

[11] Aalami, H. A., M. Parsa Moghaddam, and G. R. Yousefi. "Evaluation of nonlinear models for time-based rates demand response programs." *International Journal of Electrical Power & Energy Systems* 65 (2015): 282-290.

2. Proposal Summary

Tariff Proposal

Our proposed Demand Flex Tariff structure has four principal components outlined below. The first describes the Option; the second and third describe the overall variable price for energy and its distribution congestion component, and the fourth describes the market mechanism that we recommend for implementation of the distribution congestion adjustment.

- *Option.* Each customer on the demand flex tariff has an option (the **Option**) to purchase energy up to the amount of its Customer Profile. The Customer Profile represents an upper limit in kWh per hour based on the customer's historic load shape at a rate per kWh (the **Legacy Rate**) tied to the customer's existing Legacy Tariff.[12] If the customer purchases more than the hourly level of its Customer Profile it pays a variable price for the excess. If it purchases less than the level of its Customer Profile it pays nothing for the energy not purchased and is paid a variable price for the reduction in usage below the level of its profile and for any exported energy. While the variable price will be different for a purchase and a non-purchase variance from the Option level, they will be referred to collectively as the **Variable Rate**.

- *Variable Rate.* The Variable Rate always includes the Variable Energy Price, which is based on the congestion adjusted cost of delivering energy to the customer's location, or, if the customer is exporting energy, the congestion adjusted value to the system of the exported energy. The Variable Energy Price, in turn, includes the CAISO wholesale price, which is already reflects transmission congestion costs, and an adjustment for congestion on the distribution system.[13] For purchases, the customer also pays a per kWh base component (the **Base Price**) equal to the non-energy components of the Legacy Rate (the fixed component and the capacity component). We also suggest below an adjustment to the Base Price for the load shape of the customer's Option. Thus, for purchases above its Customer Profile level the customer pays the full Base Price *plus* the Variable Energy Price (as opposed to the flat energy component of the Legacy Rate).

Variable Price for Customer Purchases = Base Price + Variable Energy Price

For reductions in usage below the customer's Option level and for customer exports (together **Customer Sales**) the customer does not pay for the Base Costs but receives the Variable Energy Price.

[12] Below we suggest a modification based on the customer's Option load shape.
[13] In principle the Variable Energy Price should include line losses as well. These may be different for utility customers than for CCA and other LSE customers depeding on generation sources. We are omitting explicit discussion for simplicity's sake, but assume they are a part of the Variable Energy Price. Increased participation by local resources should result in reduced line losses for the system.

Variable Price for Customer Sales = Variable Energy Price

- *Local Congestion Costs.* Local congestion costs are established at substations or other distribution system elements (**Local Nodes**) at multiple levels below the Pnode (the interface of the distribution system with the transmission system). For most hours, lines in the distribution system are not congested and there will be no local adjustment (**Local Congestion Adjustment**) added to (or subtracted from) the wholesale price. However, as a particular substation or other distribution system element begins to approach its safe operating limit for either export or import, the Local Congestion Adjustment will become positive (i.e. increase the Variable Energy Price) as import limits are reached (if imports cannot be replaced by comparably priced local resources) and negative as export limits are reached.[14] At any given time, the effect on import and export prices will be the same. In other words, if a substation is import constrained, the price for energy purchasers below the substation will rise, and the payments to energy exporters or demand response providers below the substation will rise by the same amount. This granularity is a critical component that aligns Customer Resource utilization with local grid conditions not reflected in transmission congestion pricing. A customer at any location will pay a Variable Energy Price that equals (i) the sum of all Local Congestion Adjustments, both positive and negative between the customer's location and the Pnode (the **Distribution Congestion Adjustment**) *added to* (ii) the wholesale energy price. As discussed further below, in a systemwide generation shortage, the local congestion adjustments can also raise the systemwide Variable Energy Price above the wholesale price.

Distribution Congestion Adjustment = Σ Local Congestion Adjustments

Variable Energy Price = Wholesale Price + Distribution Congestion Adjustment

- *The Market.* Although the first three recommendations could be implemented in a variety of ways, we suggest a particular market structure that we believe is efficient and secure. Rather than establishing a central pricing platform that is potentially insecure as a single point of failure, we suggest that the Local Congestion Adjustment be calculated by intelligent pricing software (the **Local Pricing Server**) at each Local Node. The Local Pricing Server would have pricing information from each higher node as well as weather and other predictive information and would train itself on the behavior on its portion of the distribution system below the Local Node so that it can predict with accuracy the level of the Local Node Price Adjustment that is needed to avoid exceeding the capacity of the Local node. Customers would not need to bid, rather only respond to the cumulative price signal ideally with automated systems. The Local Pricing Server would monitor the loading on the pricing node equipment and readjust the price at frequent intervals to maintain flows within safe limits.

[14] Shayesteh, E., et al. "Congestion management using demand response programs in power market." *2008 IEEE power and energy society general meeting-conversion and delivery of electrical energy in the 21st century*. IEEE, 2008.

Some Important Results of the Structure

Certain desirable results flow directly from the structure of our Demand Flex Tariff proposal:

- *Prices are not the same for purchase and sale of electricity.* We view this as an appropriate outcome. The structure of the original Net Energy Metering (**NEM**) tariffs in California provided for an energy sale price for exports that was equal to the customer's energy purchase price. This payment, which far exceeded the wholesale price of energy, helped produce the duck curve and raised costs for other customers.

- *The price is identical for DR and exports.* This outcome is important and valuable – the benefit to the grid in maintaining system balance is identical, and the price is consistent with alternative sources of balancing energy.

- *The Variable Energy Price, is not diluted or distorted by the structure of the Option.* As discussed below, a subscription construct, with a variable price as a credit, can make arbitrary changes in the variable price incentive.

- *The proposal is simple to explain and grasp.* Customers always pay their share of system costs (the Base Cost) for all purchases. They always pay or receive the variable market price of energy for usage above or below their Customer Profile.

Consistency Across Markets

Another benefit of the MRC proposal is that it provides distribution congestion pricing that can be applied equally to all market participants. To effectively manage distribution system congestion and safeguard distribution assets requires that all power flows on the distribution system face uniform congestion related pricing. To the extent that LSEs and Aggregators use the distribution system to deliver power to customers or to deliver customer DR and exports to utilities or CAISO, the Distribution Congestion Adjustment should apply equally to affected customers of all such entities. This allows a CCA, for example, to define its own pricing independently of the distribution utility serving its customers while preserving system protection. This seems particularly important for Aggregators, who are typically offering a dispatchable product to CAISO. In preparing a bid submission to CAISO, they must be prepared to pay the Distribution Congestion Adjustment for each resource in their aggregation. If they are dispatched to provide DR or exports, their bid must cover those expected costs, or they must be prepared to dispatch resources within their aggregation that are in non-congested locations. If an aggregator submits bids and dispatches Customer Resources based on the wholesale price alone, it may call on resources behind congested local nodes at a time when the substation is near its export limit. This situation can provide many unintended consequences to distribution gird operations and as Distributed Energy Resource penetration increases will become of more concern. The same logic applies to LSE customers who elect or are automatically enrolled in a Demand Flex Tariff.[15]

As these examples point out, failure to consider the larger market context can result in unfortunate unintended consequences. Both the CEC's Demand Management Principles and the CalFUSE proposal appear to assume that retail rates can be made in a vacuum, ignoring the context of the CAISO wholesale market and the Western Imbalance Market on the one hand, and California's groundbreaking carbon market under AB 32 on the other. In the balance of this proposal we point to a number of other examples.

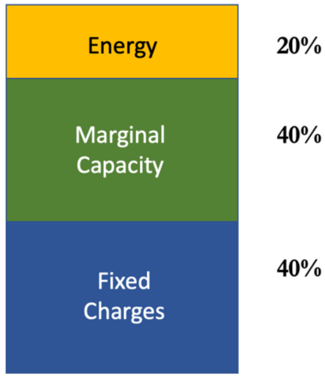
Other Necessary Reforms

The effectiveness of Demand Flex Tariff will be greatly diminished without further reforms. Currently, only NEM eligible resources, and qualified facilities can export power under Rule 21.[16] Other interconnection options are far more expensive and time consuming.[17] Moreover, within the NEM exception, a battery storage system can only be used for export if it is charged entirely by renewable energy Customer Resources and elaborate, costly physical separation of import and export wiring and inverters are required. Departing load charges and arbitrarily set demand charges discourage installation of flexible Customer Resources in the first instance. Without review and reform of these barriers to installation and operation of flexible Customer Resources, tariff incentives alone are unlikely to be be strong enough to achieve the objectives of this proceeding.[18]

3. A Simple Comparison

To illustrate the operation of our proposal and some of the ways that it differs from the CalFUSE proposal, consider the following diagram which approximates and simplifies the categories used in a General Rate Case for a full-cost recovery tariff (the **Example Tariff**):

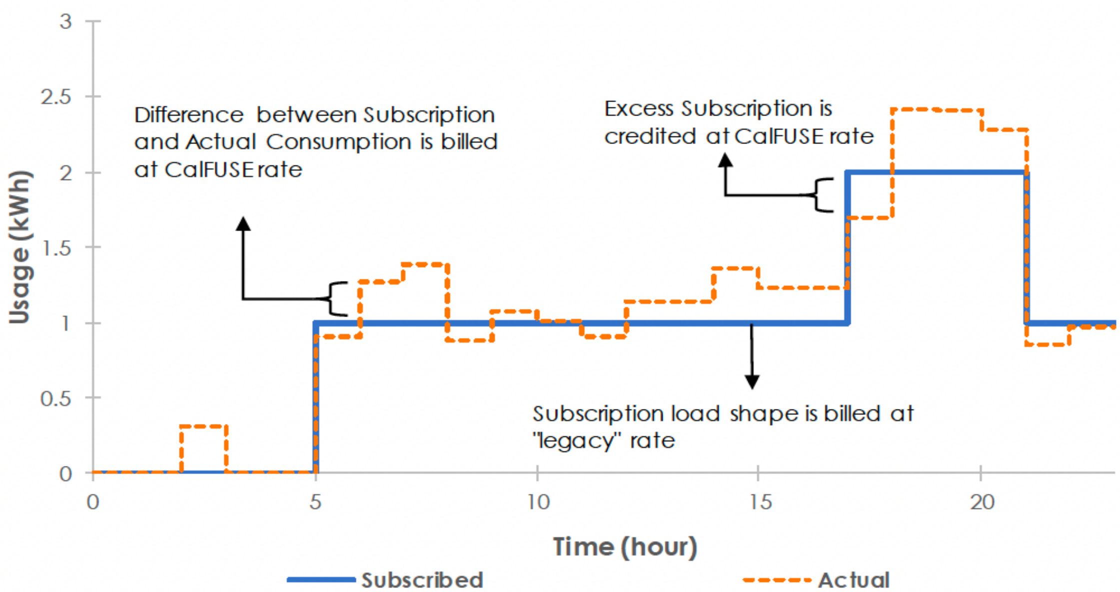
[15] Customers who lack significant demand flexibility are unlikely to elect a Demand Flex Tariff or remain in an opt-out tariff and would be unlikely to be able to provide significant value to the grid.
[16] *See*, CPUC, Rule 21 Interconnection, General Information About Rulule 21, Applicability, https://www.cpuc.ca.gov/rule21/
[17] *See,* Lori Bird et.al., Review of Interconnection Practices and Costs in the Western States, NREL (2018), https://www.nrel.gov/docs/fy18osti/71232.pdf
[18] Zhong, Haiwang, Le Xie, and Qing Xia. "Coupon incentive-based demand response: Theory and case study." *IEEE Transactions on Power Systems* 28.2 (2012): 1266-1276.



- Energy cost represents utility average cost of energy.
- Marginal capacity, including generation, transmission and distribution capacity, represent the long-term marginal cost of the respective capacity categories.
- Fixed charges represent other required or allowed charges such as demand charges and public policy mandates.
- For purposes of this example, we assume that the total retail tariff rate is 30 cents per kWh: 6 cents for energy, and 12 cents each for capacity and fixed charges.

The pricing comparisons below use this 30-cent rate and the 40-40-20 percentage breakdown from this simplified tariff model. As further discussed below, it also assumes that each customer has a Customer Controller that is preset with the customer's preferences, which responds to the price signals and is likelier to respond accurately to smaller price differentials than a customer might.

A comparison of our Proposal with the CalFUSE proposal requires comparing both how the price is constructed and how it interacts with the subscription or option to understand the net incentive effect. An illustration of the interaction provided in the Staff White Paper is set out below. The blue line represents the Customer Profile for the CalFUSE subscription and the MRC Option, in the MRC proposal. The results of divergence of actual use – the dotted orange line – from the Subscription or Option level are labeled in the diagram to correspond to the results under the CalFUSE Proposal.



The Price Proposals

The MRC proposal combines the marginal capacity and fixed charge to form the Base Price. The price for purchases above the Option level is equal to the Base Price of 24 cents plus the Variable Energy Price as defined above in the proposal Summary section. The price paid for DR (reduction in purchases below the Option level) and for exports is the Variable Energy Price. The customer only pays for what the Customer buys. The Legacy Rate is, in effect, the option strike price for purchases below the Option level.

The CalFUSE Proposal bills the customer for the entire amount of its subscription, whether used or not, at the Legacy Rate. The CalFUSE variable rate consists of fixed charges plus the wholesale price plus a component based on the capacity charges. The capacity charges, however, are not averaged over the year, but instead are allocated in accordance with a constructed curve that allocates the bulk of the charges to periods of high stress on the grid. In other words, while different examples vary, most of the capacity charges are allocated to roughly 20 percent of the hours in the year according to various measures of grid stress. The customer is then credited at the full variable price rate for usage below the Customer Profile level and pays the full variable price for usage above the Customer Profile level. The result is a variable component of the CalFUSE variable rate (the wholesale price plus the capacity component) that will always be greater than or equal to the wholesale price as used in the MRC proposal. However, the combined effect of the fully paid subscription and the crediting mechanism is a net variable incentive that can be well below the wholesale price (including being negative) while it can also be large multiples of the wholesale price in some circumstances. *This in turn will add more systemwide incentive that can overwhelm local incentives and overload the capacity of local system elements. It can also contribute to, rather than reduce system price volatility*.

High Grid Stress Scenario

According to EIA, the highest wholesale prices in CA in the last year were around $500 per MWh which translates to 50 cents per kWh. The MRC proposal price based on the Example Tariff would be 74 cents for energy purchases and 50 cents for DR and energy sellers. In other words, all Demand Flex Tariff participants would face the same energy price to sell or purchase as other real-time wholesale market participants and purchasers would also pay the Base Price to cover other utility costs on the same basis as all purchasers.

The CalFUSE variable price for purchases above the Customer Profile would be on the order of $1.34. In the absence of specific equations for the shape of the allocation curve for capacity costs, this calculation assumes that if the entire annual capacity costs are allocated to 20 percent of the hours, on average each high stress hour will be allocated five times the Legacy Rate for capacity, which would be 72 cents. Adding 12 cents for fixed costs and 50 cents for energy gives the $1.34 figure, though on the highest priced day of the year a real curve might allocate substantially more than the average to the highest price day. This corresponds to $1,340 per MWh, and could easily be $1,500 on the highest priced day.

While the CalFUSE variable price would the same for DR and exports, the customer must still pay for its full subscription and the variable price is a credit. As a result, the customer providing DR would pay 30 cents per kWh for the energy not used when the customer provides demand response and would have a net incentive of $1.04. The customer that exports would have already paid for all of its subscription in that hour and its net incentive would be the full $1.34.

Zero Energy Price Scenario

There are sunny afternoons, for example in late spring, when the CAISO wholesale price is negative at every Pnode in the state. We would suggest that the energy price for purposes of the Demand Flex Tariff would have a lower limit of zero and make that assumption for purposes of this example. On such a day a customer under the MRC proposal would pay 24 cents (the Base Price) for purchases above its option level. There would be no payment for DR or export.

Under the CalFUSE proposal no capacity charges would be allocated to zero price hours. Accordingly, customer payments for energy in excess of their Customer Profile would be 12 cents per kWh (the fixed costs). For usage below the customer's option – intended or not – the customer would *incur a net cost* of 18 cents per kWh – the Example Tariff with a credit of the variable rate. For exports the Customer would be paid 12 cents when the wholesale price is zero.

Medium Energy Price Scenario

The average CAISO real-time wholesale price for the year 2017 at 6 pm was over $60 (the highest price for the day).[19] Taking $60 for a simple example, we will assume for purposes of the example that a CAISO price in the range of $60 does not represent a grid stress condition,[20] The MRC proposal price for use above the customer's Option level would be the same as the Example Tariff – 30 cents – because the $60 per MWh translates to 6 cents per kWh, the same as the average price embedded in the Example Tariff. The price for customer DR and exports would be 6 cents. While, by assumption, DR and exports would not be relieving grid stress in that hour, they could well be contributing to a reduction in the overall energy price to other customers.

Under the CalFUSE Proposal a customer purchasing above their Customer Profile level would probably pay a variable rate of 18 cents per kWh – "probably" because we assume that no capacity costs would be assigned to an average hour. That is less than the Legacy Rate on an

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[19]Prices on the CAISO Real-Time 5-minute Energy Market, https://rstudio-pubs-static.s3.amazonaws.com/346818_b5a8bcf2101d4efeb252a6140f110c3f.html
[20] It is our understanding that stress events are rare (though not unheard of) during ramp periods, but mostly occur at system peak usage periods.

average day. A customer providing DR would *incur a net cost* of 12 cents per kWh provided because of its subscription payment. An exporting customer would be paid 18 cents per kWh, which is 3 times the wholesale price paid to other resources. The table below sets out the results of all three scenarios.

	HIGH PRICE (HIGH STRESS) SCENARIO		LOW PRICE (HIGH SOLAR) SCENARIO		AVERAGE PRICE SCENARIO	
Price Component	CalFUSE	MRC	CalFUSE	MRC	CalFUSE	MRC
Wholesale Price	$0.50	$0.50	$0.00	$0.00	$0.06	$0.06
Allocated Capacity	$0.72		$0.00		$0.00	
Fixed Cost	$0.12		$0.12		$0.12	
Base Cost		$0.24		$0.24		$0.24
Example Tariff	-$0.30		-$0.30		-$0.30	
Total for Purchase	$1.34	$0.74	$0.12	$0.24	$0.18	$0.30
Total for DR	$1.04	$0.50	-$0.18	$0.00	-$0.12	$0.06
Total for Export	$1.34	$0.50	$0.12	$0.00	$0.18	$0.06

Some Observations

Under the CalFUSE proposal, the net credit to a customer for DR is consistently below the price paid for exports. We don't believe that this is justified on economic grounds, as both services serve the same purpose for the grid operator.

On a high stress day, the CalFUSE variable price can be many times as high as the Example Legacy Price and the net payment for DR would still be well in excess of the wholesale price. The high price for DR and the higher price for exports can predictably result in enough DR and exports that CAISO would have to shut down resources with prices lower than the CalFUSE price with the net result of higher prices for all customers.

On average days the CalFUSE proposal most likely provides a net disincentive for DR. There is a large penalty for underusage on low-priced days, so, for example, a family that takes a week's vacation in March would still pay for their entire subscription for the month. It would most likely take a high stress day with a capacity component well above its Legacy Tariff value to produce a positive incentive for DR. This fails to create a level playing field for Customer Resources.

II. The MRC Proposal

The MRC proposes that a demand flexibility tariff should be based on two alternative tariff rates. The first rate, the Legacy Rate, is the customer's standard flat-rate, full-cost recovery tariff rate and applies when a customer makes energy purchases at or below its Option level. The second rate, the Variable Rate, applies to customer energy purchases above the Option level and to Customer Sales. The variable rate for purchases includes both the Base Rate and the Variable Energy Price, while the Variable Rate for Customer Sales includes solely the Variable Energy Price. The Variable Energy Price, in turn, is equal to the sum of the CAISO real-time wholesale energy price and an adjustment, the Distribution Congestion Adjustment, that reflects the locational marginal cost of delivering energy at each priced point on the distribution system.

1. The Variable Price

The Wholesale Price

3.a. How should wholesale market prices be incorporated into demand flexibility price signals?

The MRC proposes that the CAISO wholesale price be the principle variable element in a Demand Flex Tariff. This reflects our view that a retail variable price intended to elicit DR and exports from Customer resources should be based on the physics and economics of the combined transmission and distribution system. In other words, the price should equal the real-time marginal cost of delivering energy to a particular location given transmission and distribution constraints and line losses. This is how wholesale market energy is priced, and incentives to Customer Resources must integrate seamlessly with the wholesale market to avoid mis-incentives and risk to the system.[21]

Marginal Cost is generally defined in economics as the variable cost of the last unit of production, which is a function of the slope of the supply curve. For short-run marginal cost, the cost of capacity, such as factory equipment, is excluded. The CAISO wholesale price at the Pnode is designed as a real-time (i.e. short-run) marginal cost of energy *and* transmission. That price is based on generator and storage resource bids to inject energy at specific locations throughout the grid. Resources interconnected on the distribution system are treated as delivering energy to the Pnode to which they are electrically connected. If there were no capacity limits on the transmission

[21] *See*, initial comments of of economic consulting firm Tabors Caramanis Rudkevich in the initial phase of this proceeding for strong support of our pricing approach.[get link]

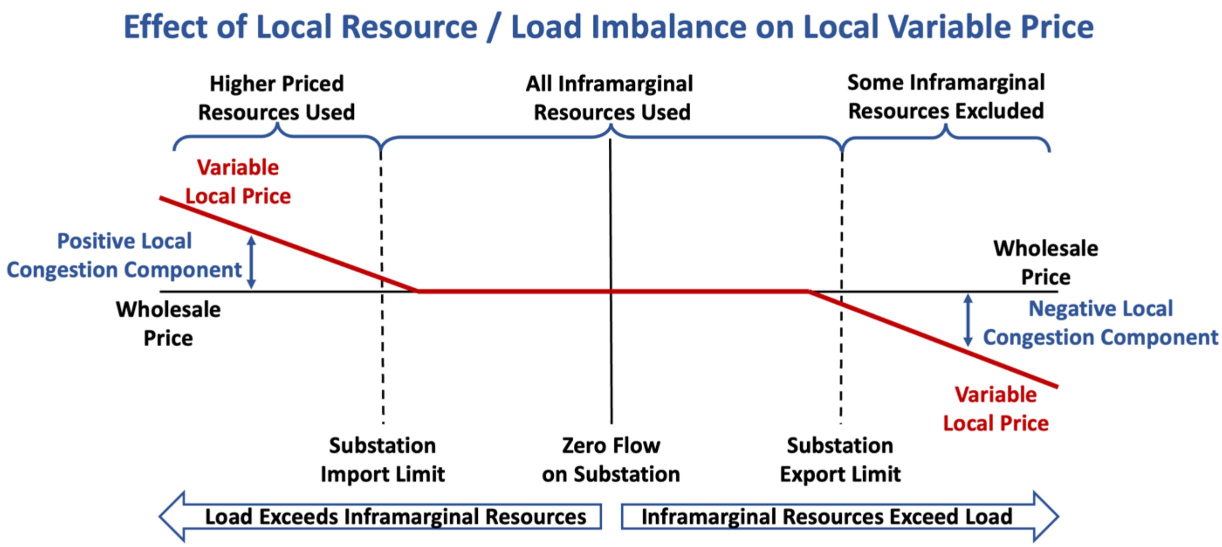
system, this would simply be what economists call an open ascending uniform price auction that establishes a single energy price for the system. There are, however, transmission capacity limits, and CAISO operates a transmission constrained least-cost dispatch of system resources. If additional energy cannot be imported to a constrained area, higher priced resources within the area must be selected until the needs in the constrained area are satisfied. The difference between the unconstrained price and the constrained area price is the "congestion price," which is the marginal cost of delivery in the capacity constrained area. The congestion price (which as defined is always positive) reflects the real-time cost of generation capacity that is the immediate non-wires alternative to more capacity on the transmission system.[22]

The Distribution Congestion Adjustment

The MRC proposes to treat capacity limits on the distribution system in essentially the same way as congestion on the transmission system. Local Congestion Adjustments will be set at Local Nodes, substation transformers, line segments, or other distribution system equipment that can be expected to experience overloading. The Local Congestion Adjustment may be positive if the Local Node is import constrained or negative if the Local Node is export constrained and will be zero during uncongested periods. It is the distribution system equivalent of the congestion component of wholesale prices. The Distribution Congestion Adjustment, in turn, is the sum of all the Local Congestion Adjustments between a customer's location and the Pnode Serving the Customer.

Like the congestion component of the CAISO wholesale price, the Local Congestion Adjustment is set by market prices paid to Customer Resources and any IFOM DER resources (together, **Internal Supply**) within a load zone served by a Local Node (a **Local Load Zone**). If the Local Load Zone is a net importer and not enough energy can be imported at the Pnode price to undercut the price at which sufficient Internal Supply resources are willing to make sales, the difference between that Internal Supply price and the wholesale price is the Local Congestion Adjustment. If the Local Load Zone is a net exporter of low-priced power, but constraints prevent the Internal Supply from exporting enough to reduce the Pnode price (the portion of the distribution system served by the Pnode is still a net importer), the price for Local Supply will be lower than the Pnode price and the Local Congestion Component (the difference between the two) will be negative. These relationships are illustrated in the following diagram, which shows the effect of the balance of resources (**Internal Supply**) and load in the Local Load Zone served by a Local Node.

[22] Liu, Weijia, et al. "Day-ahead congestion management in distribution systems through household demand response and distribution congestion prices." *IEEE Transactions on Smart Grid* 5.6 (2014): 2739-2747.



In the diagram, "**Inframarginal Resources**" refers to Internal Supply priced at or below the wholesale price. The pricing mechanism (discussed further below) will begin to raise (or lower) the price before substation limits are reached so that balance is maintained within substation limits. The horizontal axis in the diagram is not power flow, but the availability of Internal Supply (as indicated by the arrows at the bottom), which sets the price when substation limits are approached. The decline in price on the right hand of the diagram relates to offered inframarginal Internal Supply exceeding load by more than the export limit, not flow exceeding the export limit. In other words, not all would-be exporters can be accommodated and the price falls until enough of them drop out. Similarly, the rise in price on the left hand of the diagram represents use of Internal Resources with a higher price than the wholesale price to meet load, not exceeding the import limit. In other words, imports cease at the import limit and load in the Local Load Zone must be served by higher priced Internal Supply. The shape of the red "price curve" outside the import and export limits is for illustration only to show the direction of the slope and is not what would result from a particular set of resources and loads. Finally, the wholesale price will vary over time as well, with the result that varying amounts of Internal Resources will be Inframarginal Resources.

Distribution Congestion Adjustment Formation

A Distribution Congestion Adjustment as described above, requires a market, or a market-like mechanism at the local level. While that result could be accomplished with actual bids from local resources, the MRC suggests that the same result can be accomplished by a Local Pricing Server at each Local Node.[23] The Local Pricing Server monitors the flows across the Local Node and raises the Local Congestion Adjustment to induce local resources to provide DR and exports

[23] "The Future of Decentralized Electricity Distribution Networks" edited by Fereidoon Sioshansi, June, 2023, and specifically Chapter 20 by Kay Aikin, "The Future of Grid-Interactive Efficient Buildings and Transactive Energy Markets."

to avoid exceeding the import limit. In successive time intervals, if enough resources respond the price stays the same, if flows remain dangerously high, it keeps raising the price. If demand drops safely below the limit the reverse process happens. Similarly, if excess Internal Supply approaches the export limit, the Local Pricing Server reduces the Local Congestion Adjustment below zero so that the price within the Local Load Zone is below the wholesale price. It keeps lowering (further negative) or raising (less negative) the Distribution Congestion Component to keep overall exports safely within the Local Node export limit.

Whether the Local Congestion Adjustment is positive, zero, or negative, the Local Pricing Server calculates the Variable Local Price by adding the Distribution Congestion Price to the Pnode price (and a calculated value of line losses between the Pnode and the substation) and transmitting it to all the sub-nodes in the Local Load Zone, or if it is the lowest level local Node to Internal Supply in the Local Load Zone. The Internal Supply resources (to the extent not subject to direct CAISO dispatch) would respond by their performance in response to the price. The Local Pricing Server would recognize the aggregate response in the form of substation flows and readjust the price creating a collective two-way communication flow. Customer meter data can disaggregate that communication flow after the fact (or immediately with smart two-way meters) as needed.[24]

Like the wholesale market, this mechanism creates a security constrained open ascending uniform price auction. Every responding Internal Supply resource gets paid the same transmitted Variable Energy Price, including the local Distribution Congestion Adjustment, no matter whether it might have been willing to respond for less. The difference is that the Pricing Server makes an offer, and the resource accepts, rather than the resource bidding and CAISO accepting and dispatching. Since there is no dispatch command, the response to price changes is a statistical response that is less firm than a dispatch response (although a dispatch response is also inherently less than firm, which is why the system needs reserves). The shorter the pricing intervals the more accurate the response can be, and a further safety margin can also be obtained with a conservative pricing algorithm. Machine intelligence in the Local Pricing Server should allow continuous refinement of the pricing algorithm to better match its pricing to local resource abilities and price sensitivity. Ultimately, the utility may wish to locate a battery at vulnerable substations or to procure a non-wires alternative contract with a rapid-response resource in the Local Load Zone to assure the safety margin.

Finally, the Proposal has certain advantages over bidding-based proposals that go beyond the characteristics of the price itself. First, it is inherently more secure than other pricing mechanisms that involve transmitting more information to more places. Substation loading

[24] Liu, Weijia, et al. "Day-ahead congestion management in distribution systems through household demand response and distribution congestion prices." *IEEE Transactions on Smart Grid* 5.6 (2014): 2739-2747.

information need go no further than the substation Pricing Server. The price must be distributed to local customers, but individual customer response information is not required. In addition, while the discussion above has been couched in terms of one Local Node, the pricing system can be extended to multiple layers so that it reflects congestion at finer and finer levels of the distribution system. Absent loop flows, the price at each level would simply be the price from the Local Pricing Server at the layer above plus the Distribution Congestion Component for the Local Load Zone served by the Local Node. Each Local Node can also report upstream, so the distribution utility (or DSO) has a complete picture of system pricing. A further advantage of this fractal structure is that it can be implemented incrementally by layer or by high stress sections as in Non-Wires Alternatives (NWA) situations. It can be installed first at high level substations and later expanded to lower levels while still making use of the original upstream infrastructure.

It is important to recognize, that while paying Customer Resources the Variable Energy Price is the correct economic signal for real-time system operation, such payments do not guarantee that Customer Resources will recover their full long-term cost of operation including amortizing their capital investment. The California system provides resource adequacy payments intended to ensure adequate investment in generating capacity. For a behind-the-meter Customer Resource, which is not exporting regularly, having a payment of uncertain size for an uncertain amount of hours will not support investment. A capacity payment in return for a commitment of a specific number of high load hours in which the Customer Resource agrees to be dispatched, by contrast, would effectively support customer investment.[25] This will be discussed further below, but if such a program is adopted the correct energy price to pay during the hours the resource is dispatched is the Variable Energy Price.

Distribution Adjustment Mechanism and System Stability

As the CEC has identified, to transition the California grid from a fossil fueled generation fleet to a fully decarbonized one will require increasing grid flexibility for the optimized management of the system. Careful thought needs to be made at how to structure this new grid with proposed deployment of millions of coordinated devices, in a way that is:

- Customer centered;
- And also,
    - Scalable,
    - Adaptable,
    - Extensible,
    - Stable, and

[25] For a discussion of the factors affecting credit analysis for DER investment *see*, C. Baird Brown, *Financing at the Grid Edge,* 48 Environmental Law Review 10785 (2018) at 10789-10792, https://lpdd.org/wp-content/uploads/2019/05/06-LPDD-Financing-at-the-Grid-Edge.pdf.

- Cyber-secure.

As the grid deploys more 'coordinated' devices it will naturally become more complex and be more like a computational ecosystem with distributed intelligence throughout the grid at multiple levels."[26] The electric grid is becoming an example of an Ultra Large Scale System, and there is a significant and growing body of research on system stability in such systems. Glance, Hogg, and Huberman demonstrated[27] that in a computational ecosystem, system stability prevails if price changes are slow and small (low frequency and amplitude) as compared to overall system response time. "They also observed that external modulation (as would be obtained by adding storage at the T/D interface - and a likely result during the energy transition) the stability envelope increases."[28]

We suggest a variety of approaches be deployed to meet the competing concerns of scalability, adaptability, extensibility, cybersecurity, and stability. These include:

- *Include day-ahead prices in the information feed to Customers.* This gives Customer Controllers additional information about overall system status in the wholesale market as well as future local congestion estimates and helps promote stability and overall optimization opportunities.
- *Use a pricing time intervals no more than 1 hour or less than 5 minutes.* This maximizes stability and minimizes cycling of edge devices.
- *Local Load Zones should have a peak load of no less than 3 to 5 MW.* Layering of the grid below the pnode should be implemented by substations and circuits that have a sufficient number of Customer Controllers, sufficient customer and Customer Resource diversity, and (absent other damping mechanisms behind customer meters) sufficient non-participating load.
- *Provide a system supply shortage mechanism*. In circumstances of systemwide supply shortage, the CAISO wholesale price may not fully reflect the cost to serve load. Local Price Servers at the highest level below the Pnodes can treat this as a collective import limitation and continue to raise prices to attract more customer resources, thus increasing the collective Distribution Congestion Adjustment. This has the benefit of being a market based price that matches the cost to utilities of meeting load, not an arbitrarily constructed curve.

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[26] A more compete analysis of the challenges in managing the future grid can be found in a newly published book "The Future of Decentralized Electricity Distribution Networks" edited by Fereidoon Sioshansi, June, 2023, and specifically Chapter 20 by Kay Aikin, "The Future of Grid-Interactive Efficient Buildings and Transactive Energy Markets."

[27] Glance, Natalie, T. Hogg, B.A. Huberman, Computational Ecosystems in a Changing Environment, International Journal of Modern Physics, September 1991, DOI:10.1142/S012918319000974

[28] "The Future of Decentralized Electricity Distribution Networks" edited by Fereidoon Sioshansi, June, 2023, Chapter 20 by Kay Akin "The Future of Grid-Interactive Efficient Buildings and Transactive Energy Markets, at 455

Relationship to the CEC Load Management Standards

3.f. How should demand flexibility rates be designed to comply with the California Energy Commission's amendments to the Load Management Standards?

The California Energy Commission Load Management Standards,[29] which set overall requirements for the Demand Flexibility Proceeding state:

> Total marginal cost shall be calculated as the sum of the marginal energy cost, the marginal capacity cost (generation, transmission, and distribution), and any other appropriate time and location dependent marginal costs, including the locational marginal cost of associated greenhouse gas emissions, on a time interval of no more than one hour.

The short-term marginal cost of generation, transmission, and distribution are already captured by the Variable Energy Price as discussed above. By contrast, marginal capacity cost is a concept used in General Rate Cases to allocate each utility's revenue requirement among rate classes and rate categories. It is an annual value for the long-term marginal cost of capacity additions over time frames in which capacity additions can be made.[30] As described more fully below in Part 3 Section 2, we suggest incorporating capacity costs into a price adjustment for Option load shape.

The Load Management Standards contemplate that the Total Local Price is a complete, full cost recovery price that is calculated entirely separately from the Legacy Price. Current proposals being considered in Track B Working Group 1 seek to separately allocate each of these marginal capacity elements as separate variable elements in the Variable Total Price, often using arbitrary curve fitting. Adding these costs to real time prices takes a cost causation approach, but the price signal that is needed from the point of view of economic efficiency is the real-time marginal cost.[31] The real-time marginal cost, as discussed above, is the actual current utility cost of delivering energy to transmission or distribution constrained areas. Adding additional capacity cost elements that are not already covered by the congestion costs described above will distort the incentives of Customer Resources as compared to other resources and will result in increased overall costs by crowding out lower priced resources if they are available. If they are not available, our proposal would provide increasing congestion prices to Customer Resources to the extent needed to balance the system.

The quantity of net exports from or imports to a Local Load Zone depend on the balance between load within the zone and Internal Resources. Incentives to reduce load and to run

[29] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-OIR-03
[30] Staff White Paper at 53.
[31] Motalleb, Mahdi, Anuradha Annaswamy, and Reza Ghorbani. "A real-time demand response market through a repeated incomplete-information game." *Energy* 143 (2018): 424-438.

generation resources (or discharge batteries) play the same role in managing risk to the substation. The incentives for each should be symmetrical. If the demand response incentive embedded in the Variable Price is calculated at a different rate than for exports, it puts the substation at risk. As an example, consider a battery that is a Customer Resource. If the Customer charges the battery using purchased power, it pays a full cost recovery price, which includes the cost of energy (whether averaged or variable) as well as the Fixed Cost Component. If the customer later discharges the battery in response to Local Node prices, it should receive the current Variable Energy Price whether that discharge results in demand response or export or both. If instead the customer gets for demand response a version of the Full Local Price that contains a mixture of capacity elements fitted to an arbitrary curve reduced by the Legacy Price, the result can vary arbitrarily from the Variable Energy Price. This will produce misaligned incentives and inconsistent results for different customers.

The MRC recognizes that the need for aggregate system transmission capacity and for local peak distribution capacity (which may well be non-coincident) are driven by relevant peak loads. We do not oppose the suggestions that have been made to seek FERC approval for an allocation of residential transmission charges in a way that more accurately reflects cost causation. To the extent that such payments were to be made under a demand Flex tariff, however, they should come from customer transmission charges with a demonstared nexus to the expacted savings, which will be difficult to establish. Further, we believe that our local congestion pricing proposal is by far the most effective way of identifying and pricing local congestion. It essentially pays the cost of a day-of purchase (i.e. not dispatchable) of a non-wires alternative. Distribution Utilities do not own and directly manage generation. Rather, capacity is managed through resource adequacy (**RA**) requirements. Any payments under a Demand Flex Tariff should be tied to a demonstable reduction in RA payments. As discussed below, an effort to include GHG emission costs in the calculation would be double counting and would discourage electrification as compared to non-electric resources.

Marginal GHG Prices

> 3.c. How should the timing of customer exports be aligned with grid needs to reduce greenhouse gas emissions, reduce curtailment of renewable energy, and enhance system reliability?

The CEC's Load Management Standards also suggest that the price include a "marginal GHG price." As with the capacity prices discussed above, the MRC believes that the marginal cost of GHG emissions is already included in the CAISO wholesale price. As a preliminary matter, GHGs don't have a direct marginal cost for time or location of emissions. The effects of GHG emissions on the planet are cumulative, long lasting, and planet wide. However, to the extent that meeting periods of high demand means calling on high-priced generators that in some cases are the dirtiest generators, there can be higher emissions per MWh in periods of high demand, and a flatter demand could result in in lower aggregate emissions for the same MWh of consumption.

California has a cap-and-trade GHG emissions auction system under AB 32.[32] Dirtier generators pay a higher carbon price per MWh of generation as a result. They need to include the cost of purchasing allowances for those emissions in their energy bids (or lose money selling power). In other words, the marginal cost of being a dirtier generator is already factored into the wholesale prices calculated by CAISO. To apply a separate charge would be double counting. This would mean, for example, that electricity would pay a comparatively higher price for carbon emissions than transportation and heating fuels when the state has a goal to phase out fossil fuel vehicles in favor of electric vehicles and and similar goals for building decarbonization.

Small generators (under 5 MW and some as large as 10 MW) are not covered by AB 32. We have recommended to the Commission in other contexts that they consider imposing an emission charge on smaller generators (including diesel backup generators!) based on the CO_2e price established in the AB 32 auction. This would be a substitute for the welter of technology-based standards that are imposed on small DERs today and would avoid distortion of local prices as compared with utility scale generation.

Revenue Neutral Pricing

The CalFUSE proposal suggests that the Variable Price should be a full cost recovery price. We agree that this is an important principle. However, the structure of the CalFUSE proposal with an arbitrarily constructed variable price and a netted against the subscription payment makes is unlikely to be revenue neutral in effect. Assuming that the Variable Price is a revenue neutral price, at current usage levels, its intended effect is to reduce load in high priced intervals. This can occur through load reductions or load shifts. Load reductions will simply increase utility costs. (Presumably customers will only deliberately reduce load when the Variable Price is above the Legacy Price.) If they make a beneficial shift in load it will be to periods when the allocation of capacity costs to the Variable Price is low. This too results in lost revenue. In the MRC Proposal, the utility receives the Base Cost for all purchases without deduction. While the cost of energy varies, the utility will pay or be paid its actual cost of energy from alternate sources at all times the variable rate is in effect. There is no net utility cost increase. It's experience of those rates should feed back through to the Legacy Tariff in general rate cases.

The case for a Demand Flex Tariff rests in large part on expectations of system-wide savings. Such savings will come immediately in the form of reduced system prices and over time in the form of reduced needs for investment in distribution and transmission. The MRC does not suggest that the Commission ignore those benefits, indeed we support their consideration.

[32] Global Warming Solutions Act, AB 32 (Pavely, Nunez, 2006)

However, in the absence of a demonstration that the market-based pricing we suggest is inadequate to achieve those benefits, we see no reason to embark on a more complex path.

2. The Option

3.b. What options should be provided to help customers plan and manage their bills (e.g. customer load shape subscriptions, forward transactions, bill protections)

Basic Option Structure

The MRC suggests use of an Option rather than a subscription as a customer risk management tool. The customer is entitled but not obligated to purchase up to the Customer Profile level at the Legacy Price. For amounts in any hour less than or equal to the Customer Profile level the customer pays the Legacy Price (which, again, is the Base Price plus an averaged energy charge expressed as a per kWh price). For amounts above the Customer Profile level, the customer pays the Variable Price (including the Base Price and the Variable Energy Price). If the Customer does not use its entire Customer Profile amount in a time interval, the customer pays only the Legacy Price for the customer's actual usage and is paid the Variable Energy Price for the customer's reduction. This eliminates the distortion of incentives described in Part 1. By contrast, the CalFUSE subscription in effect acts as a full-requirements fixed charge (the customer is obligated to pay the full monthly charge regardless of usage), which violates cost causation principles[33] and is not what is contemplated by AB 205.[34]

The proposals under consideration in Track A for tiered fixed charges in response to AB 205[35] are clearly intended to provide reduced bills for low-income customers, an equitable result that the MRC would generally support. The choice to provide utility recovery of fixed costs in part through a fixed charge versus through volumetric rates does not affect the operation of the Demand Flex Tariff so long as the Variable Energy Price is not affected. Fixed charges do, however, create other longer-term distortions, especially at the levels currently proposed by the utilities. They directly reduce customer incentives to install Customer Resources and building retrofits for energy efficiency.[36] Those customer investments avoid the need for investments in new utility scale

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[33] Commission Ratemaking Principle 3 states "Rates should be based on cost causation."

[34] AB 205 (2022) establishes graduated fixed charges and states in pertinent part: "The fixed charge shall be established on an income-graduated basis with no fewer than three income thresholds so that *a low-income ratepayer in each baseline territory would realize a lower average monthly bill without making any changes in usage*." (Emphasis supplied.) A fixed charge based on full historic usage as proposed as a subscription fails to comply with this requirement. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB205

[35] Ibid.

[36] McLaren, Joyce, et al. "Impact of rate design alternatives on residential solar customer bills: increased fixed charges, minimum bills and demand-based rates." *The Electricity Journal* 28.8 (2015): 43-58.

generation that are paid for by utilities and other LSEs either directly or through long-term contract pricing, and new distribution and transmission to deliver the output of new resources, and that, in turn, reduces prices for all ratepayers. Customer investments will also drive reductions in GHG emissions. To the extent that demand charges are required under act 205, we strongly support keeping them low.

Customer Profile Setting

A Customer Profile is based, in principle, on the customers historic usage levels and load shape. Setting the Customer Profile for an Option is similar, and subject to similar difficulties, as setting a Customer Profile for a subscription under the CalFUSE Proposal. If the Customer Profile is set higher than the customer's typical usage, the customer can profit by using less on a regular basis. On the other hand, if a Customer Profile is too low, it fails to serve as a risk management mechanism. The goal is to make the level and shape as fair and accurate as possible. This complex task provides no easy answers, but we offer some suggestions.

Past customer usage provides the most straightforward way to begin. Different years' weather and other factors make for variations in common with other customers, and some variety of smoothing seems appropriate. One straightforward way would be to take a three-year average (perhaps weighted more toward the most recent years). If the Customer Profile is readjusted every year to the past year's usage, as some propose, it will ratchet down on customers who frequently respond to the Variable Price and penalize them in future years. We could potentially set all subscription levels (above a base usage) to a level somewhat below past usage to provide an onging incentive for conservation. We can also look to see if the customer used less total energy, as opposed to shifting load to lower priced times. A total drop should be reflected (perhaps on an averaged basis as discussed) in the reduction of the level of Customer Profile. Finally, we would hope to provide a mechanism for adjustments for significant changes in net load (such as when a factory expands and installs new equipment or a customer adds solar).

Allowing customers to select a reduced or zero Customer Profile, by contrast, does not present a moral hazard. Instead, it leaves a customer at greater risk. Sophisticated microgrids with multiple internal generation and storage resources, can manage that risk, to their benefit and the benefit of the grid. See Appendix A for an example of the performance of the Princeton University Microgrid. However, we do not suggest such an option for residential customers without individual approval as to the capabilities of their Customer Resources and Controller and, perhaps, financial capability.

The Cost of an Option Load Shape

As a final matter, different load shapes have different costs to the grid. We suggest consideration of an adjustment to the Base Price in the MRC proposal to account for that, at least for customers with consumption above a floor level.[37] A load shape that includes high usage during system peak hours puts greater stress on capacity resources of all sorts. By contrast a load shape that is flat or even inverse to system peak helps to reduce stress on capacity resources and limits the need for ramping capacity. The Option load shape is in effect for a full year or could be allocated quarterly or on a more specific pattern to account for seasonal variations. This time frame is consistent with the annual calculation of marginal capacity costs and would not dilute or exaggerate real-time price signals. This partial reallocation of capacity costs would be uniform across a utility service territory for similar load shapes. It is deliberately not intended to vary with local congestion.

III. Other Considerations

1. LSE and Aggregator Parity

3.e. How should demand flexibility rates be designed to enable all load serving entities to have the option to participate?

Non-utility load serving entities (**LSEs**) such as CCAs must be able to offer demand flexibility pricing to their customers and may control DERs within their service territory. Aggregators selling pooled DER services pursuant to FERC Order 2222 are dealing directly with CAISO. All LSE customers participating in demand flexibility programs and all DERs located in Local Load Zones must be obligated to pay (or entitled to be paid) the Distribution Congestion Adjustment, with respect to purchases, DR, and exports so that they face the same incentives as participants in utility programs. Customer Resources participating in aggregations will also face the wholesale price. Failure to accomplish this is not only inequitable but puts substations at risk. An LSE's marginal cost of energy at a Pnode may be different than the wholesale price depending on its wholesale purchase arrangements and if it has supply resources within its territory may experience different aggregate line losses. LSE's should be able to structure the energy cost component of their tariffs accordingly. An aggregator that is selling a dispatched product may be willing to pay a different aggregate price for the value of dispatchability. Those differences can be accommodated, but the Distribution Congestion Adjustment from the Pnode to the customer location must be the same for all Customer Resources and IFOM DERs. An aggregator whose resources are located in areas served by different Pnodes, or even different Local Load Zones, must be prepared to face additional and varied costs for its aggregated resources. This may cause it to need a portfolio of resources that in effect give it reserves to meet its bids.

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[37] The floor could be raised for medical baseline customers if needed.

2. Equity and Accessibility

3.d. How should demand flexibility design consider the barriers and needs of low-income and disadvantaged communities and advance the Commission's Environmental and Social Justice (ESJ) Action Plan goals?

A demand flexibility program must assure access to low-income customers and customers in disadvantaged communities. It must be understandable and user friendly for all customers. While the internal structure of this or any tariff is fairly complex, the result can be described in a straightforward way. Each customer is entitled to their regular usage at the Legacy Price, and, if they use more or less power, they will pay or be paid a price based on how busy the grid is at the time (the Variable Price). They can save money by using less when others are using more, and they can set their home controller to do that for them automatically. To make this work, the customer needs the home controller and the connectivity (through whatever channel is chosen) to receive pricing information. This should generally be of the customer's choosing – a customer may choose simple equipment or a sophisticated microgrid controller, so long as it meets system standards for interoperability. To provide access to folks for whom the price of participation is a challenge, programs can provide on-bill financing (which may be self-funding through savings) or direct utility installation. The state should be prepared to assist low-income customers with internet connectivity.

To increase access and equity for renters, we recommend that any impediments to master metering of multi-unit buildings be eliminated. This allows a Customer Controller for the entire building to manage overall building load for the benefit of the residents. A proposal to implement such an arrangement was outlined in the Shared DER Tariff filed by Ivy Energy on March 21, 2023 as part of proceeding R.20-08-020.[38] The principles of a shared DER tariff for multi-unit buildings include conducting netting on an energy basis (kWh) at the property level and accurately accounting for onsite electricity consumption and exports. This approach allows collective optimization and simplifies transactions.[39] The property as a whole can respond to the Variable Price for exports and imports, which will incentivize whole-property load management and maximize system benefits.

Other equity issues arise because of idiosyncratic variations in distribution system capacity. More frequently congested substations or feeders will more often face a high Variable Energy Price, or alternatively may face a low DR and export incentive. The Option will reduce most customer risk related to high Variable Energy Prices, and while some will remain, it will be at the margin. Additionally, a customer will have the option to simply not participate. Lack of

[38] https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=504319101

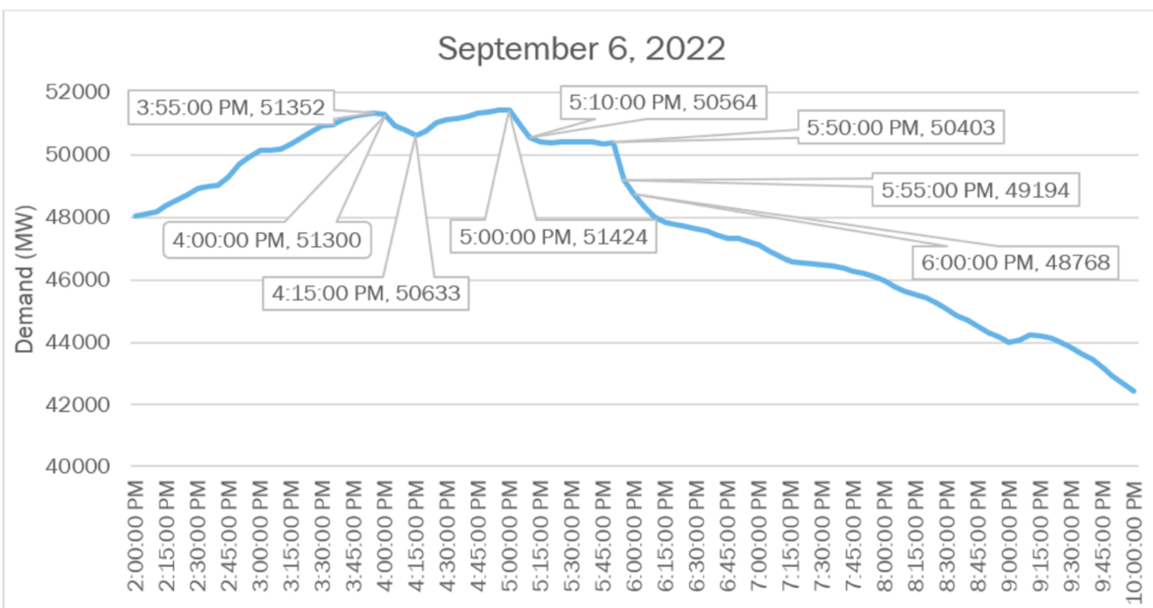
[39] Martirano, Luigi, et al. "Demand side management in mixed residential/commercial buildings with PV on site generation." *2017 IEEE/IAS 53rd Industrial and Commercial Power Systems Technical Conference (I&CPS)*. IEEE, 2017.

opportunity for a customer to reduce the customer's bill by providing services to the grid is perhaps more serious but at least not a direct negative impact. Where this occurs in disadvantaged communities, the Commission should require utilities to prioritize upgrades.

Finally, for low-income customers energy expenditures can make up a disproportionate share of their houselold budgets. Programs that allow them to participate in the benefits of locally sourced and owned DERs, from individual solar to community microgrids, reduce energy burden and build individual and local wealth. A demand flex tariff that provides payments or cost reductions that partially support these local investments creates an improved climate for local wealth building.

3. Participation

Successful operation of a Demand Flex Tariff will not require mandatory participation. The system needs enough customers to join in to have a meaningful effect on system loading, not even majority participation. When Governor Newsome called for voluntary conservation on September 6, 2022[40] it took less than seven percent of aggregate reductions in net load to avoid system shutdowns and brownouts.[41]



Source: California ISO (CAISO). *Grid Emergencies History Report*. http://www.caiso.com/Documents/Grid-Emergencies-History-Report-1998-Present.pdf.

[40] Governor Newsome, *Proclamation of a State of Emergency*, available at, https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf

[41] Dr. S. Dreyer, *Electric Demand Response-ability, Opinion Dynamics,* https://opiniondynamics.com/electric-demand-response-ability-in-california/

CAISO estimates that 1300 MW of the reduction came from demand response including 500 MW from voluntary demand resonse.[42] Moreover, demand response participation in well structured programs in other jurisdictions has greatly exceeded initial utility expectations.[43]

IV. Implementation

1. Infrastructure

4. How should the Commission ensure access to dynamic electricity prices by bundled and unbundled customers, devices, distributed energy resources, and third-party service providers? What systems and processes should the Commission authorize for access to prices and responding to price signals?

We believe that our proposal minimizes the cost of hardware and software for price formation and communication. It requires communication of prices to customer residences and facilities, but so do all transactive energy programs. That communication can be implemented by internet, cable, or smart meter communication such as cellular nets or even by FM radio. Once this communication network is in place, more frequent pricing for better load tracking does not involve extra cost. The proposal requires Local Pricing Servers at each Local Node, but that is what allows pricing that protects the substation. It also allows any Local Load Zone, or a collection of Local Load Zones served through a common Local Node to act as a mini-grid if the larger grid is disrupted, with locally determined prices serving as a key element of the balancing mechanism. This grid sectionalization supported by DERs is the future of grid resilience.

Implementation of demand flexibility also requires a home or facility controller (the **Customer Controller**) at each customer's residence or facility. The controller could be as simple as a smart thermostat or an EV charger, but with more than two devices a central controller would be preferable. Such devices are now available with increasingly simple and user-friendly graphic controls. The preprogrammed Customer Controller responds to price signals from the Local Pricing Server and modifies load, or battery operation accordingly. If flexible generation resources or storage (or both) are included, the Customer Controller can become, in effect, a microgrid controller. The alternative is an internet of things approach in which each thermostat, battery, appliance, and vehicle charger talks directly to the grid using different software that must be separately programmed and may operate at cross purposes. While the Pricing server can manage that, the result for the customer is likely to be suboptimal. One of the Commission's ratemaking

[42] CAISO, *Summer Market Performance Report September 2022*, at 14.
[43] Jemma Green, *Why No One Saw The Success of Demand Response Coming,* Forbes, January 27, 2023, https://www.forbes.com/sites/jemmagreen/2023/01/27/why-no-one-saw-the-success-of-demand-response-coming/?sh=498a8b8e3700

principles is to give customers control of their bills. A single Customer Controller that is managed by the customer serves this principle, is relatively inexpensive, and responds better to the needs of the grid. Investing in Customer Controller and the resources it controls is what makes enrolling in a demand flexibility tariff worthwhile to the customer. Energy efficiency contractors, solar installers and microgrid developers will be the best marketers for widespread adoption of both the controllers and the tariff.

2. Regulatory Implementation

There are several corresponding regulatory and infrastructure improvements that should be implemented. Rule 21 must be amended to permit exports under the demand flexibility tariff by Customer Resources that do not qualify for net metering or as qualified facilities. Rule 18/19 restrictions on battery charging and discharging (and especially requirements for separate inverters or duplicate wiring) should be eliminated. In the process the Commission will need to review the interaction between the net metering tariff and the demand flexibility pricing. Eventually solar resources should face the same export pricing as any other Customer Resources. Utilities should plan for expansion of Customer Resources and build out the distribution system to remedy legacy physical limits on interconnection and export, especially where they affect disadvantaged communities. In improving the system, utilities should consider contracts with DERs to serve as non-wires alternatives by being available to alter the balance between load and resources in Local Load Zones. Finally, the Commission should adopt an emergency capacity tariff that pays DER a price for capacity that is the performance-based equivalent of the RA payment for being available for dispatch during periods of grid stress for up to a limit such as 200 hours per year. The energy price paid to such resources when called should be the Variable Local Price.

V. Conclusion

The MRC offers this proposal as a starting point for discussion. We believe that it offers multiple advantages:

- *The pricing is straightforward and relatively easy to explain.* Customers always pay utility Base Costs for purchases and pay or receive the wholesale price for puchases above and for DR below their Option level and for exports.
- *The pricing is consistent with larger markets.* It uses the CAISO wholesale price and relies on California's existing carbon market.
- *It is easy to implement in stages without ending in a blind alley.* Wholesale prices are available without further investment, as are existing tariff components, and Variable Local Prices can be implemented gradually.
- *It opens energy markets to all customers without subsidy or distortion.*

We look forward to the discussion.

Respectfully submitted,
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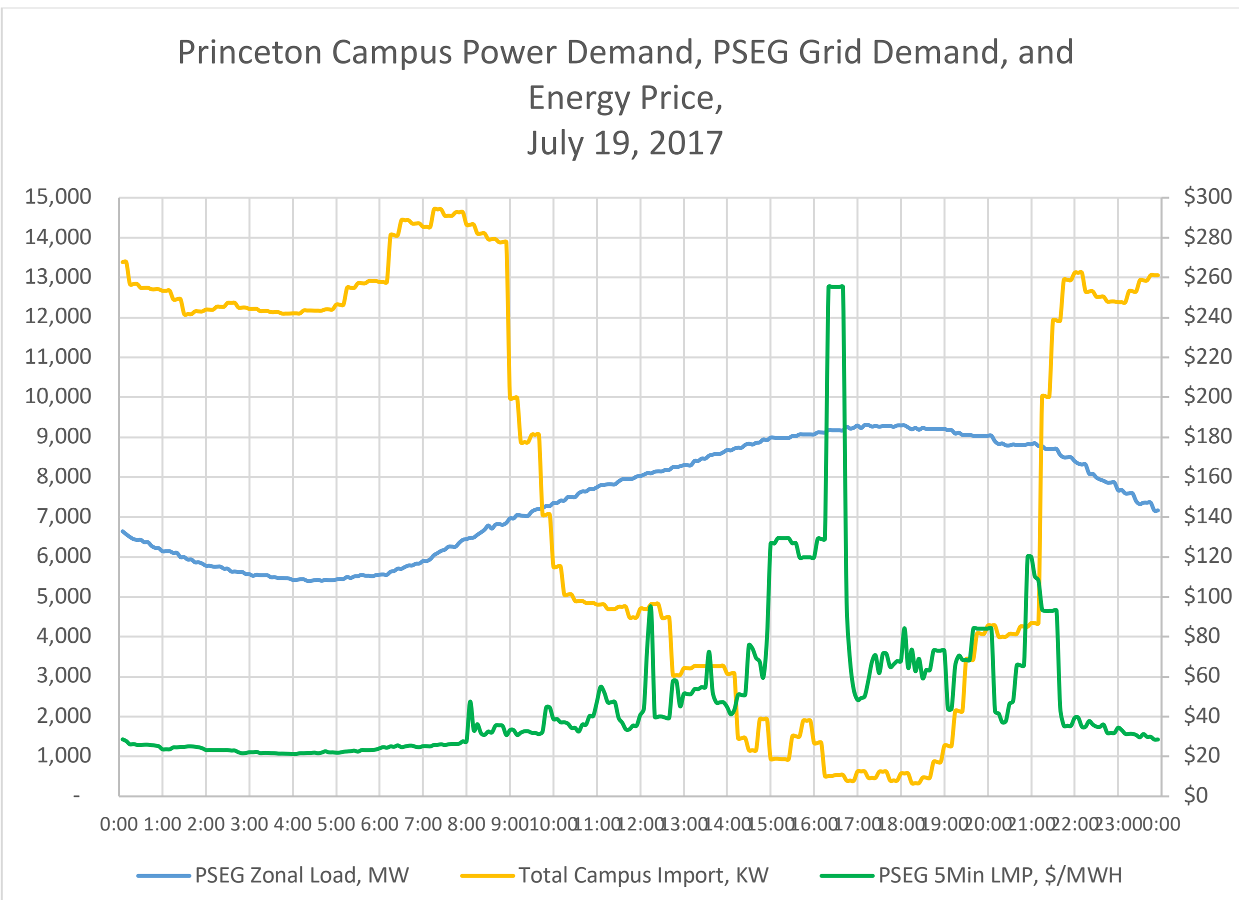
ATTACHMENT A

Princeton University Microgrid Performance

The Princeton University campus is served by a microgrid that includes 15 megawatts (MW) of gas cogeneration, 4.5 MW of solar generation,[44] 40 megawatt hours (MWh) equivalent of thermal storage, advanced building controls, and an advanced interface with the grid. The graph below shows wholesale market energy consumption and price for the Public Service Electric and Gas (PSEG, the electric utility serving Princeton) service territory and the Princeton campus energy purchases from the grid, all plotted against the time of day. The data is for July 19, 2017, one of the days when the entire regional grid operated by PJM Interconnection, LLC (PJM) was near system peak capacity.



[44] Since expanded to 12 MW.

* Note that system load and campus imports use the same left margin scale, but system load is in MW and campus imports are in kilowatts (kW). LMP denotes the "Locational Marginal Price," which is the wholesale price specific to each utility service territory, in this case PSEG.

The chart shows that Princeton purchased a substantial amount of electric energy in the early morning to charge its thermal storage—chilled water in an insulated tank. It then purchased almost no electric power at the time of peak usage and peak pricing on the PJM system. This result at peak was achieved by 15 MW of cogeneration and 3.75 MW of solar. Campus potential peak load of around 27 MW was reduced to around 19 MW through use of steam chillers supplied by heat from the cogeneration plant and discharge of chilled water from the thermal storage tank. Princeton avoided purchasing high-priced power (the prices reached \$255.00 per MWh), and reduced its obligation to pay transmission charges, which are allocated according to customer usage at system peak. Princeton paid a weighted average of \$34.06 per MWh for power that day compared to a system average price of \$50.17 per MWh. On more ordinary days, Princeton may dedicate a portion of its generating capacity to providing frequency regulation, an ancillary service that provides balancing energy (up or down) to the PJM system in less than 10 seconds following a signal from the grid operator. Collective control of multiple grid-edge resources allows Princeton to manage for efficiency, price, and reduced carbon.[45]

[45] Data on the Princeton system supplied by Edward T. Borer, energy plant manager, Princeton University.