Title

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Abstract

As California seeks to meet its ambitious goals for carbon reduction and support of an electric grid with high levels of renewable energy supply, there is a growing need for large amounts of flexibility from the demand side. This report outlines a system architecture and technology infrastructure to enable dynamic pricing to be used to finely tune coordination between the grid and its customers. Taking a cue from the success of internet architecture, this system — Price-Based Grid Coordination — emphasizes simplicity and universality. It enables a wide variety of ways for prices and other signals to pass from the grid to individual flexible loads and other devices, including multiple possible locations for the intelligence that combines price signals with device functional needs. The report includes a reference data model to knit together information at the utility level, communication protocols, and customer devices, to be independent of any particular protocol. The report also contains a roadmap for technology standards development needs, and a review of the current California policy developments that intersect dynamic pricing.

Key conclusions from the report are:

- Existing methods in use to coordinate distributed energy resources (DER) all have significant shortcomings.
- The technology exists today to support time-varying prices that change frequently.
- An overall system architecture is needed to enable multiple methods for communicating and controlling flexible loads and other DER.
- A standard data model for "streaming" electricity prices can enable simplicity and interoperability.
- Technology standards do need to evolve to make price distribution easier to use, more interoperable among protocols, more efficient, and more capable.
- State policies can support this process, to move the market to a simple and universal mechanism for coordinating flexible loads and other DER with utility grid needs.
- The needed first step is to make appealing highly dynamic prices available to customers; only then will we see substantial introduction of products that can use these prices.

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Acronyms

ADR	Automated Demand Response
API	Application Programming Interface
ASP	Automation Service Provider
BTM	Behind the Meter
CAISO	California Independent System Operator
CPP	Critical Peak Price
CTA	Consumer Technology Association
CA	Coordination Architecture
CCE	Customer Central Entity
DLC	Direct Load Control
DR	Demand Response
DOE	U.S. Department of Energy
DER	Distributed Energy Resource
EV	Electric Vehicle
ESI	Energy Services Interface
FDAS	Flexible Demand Appliance Standards
FTM	Front of the Meter
GHG	Greenhouse Gas
GMLC	Grid Modernization Laboratory Consortium
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor Owned Utility
ISO	International Organization for Standards
JSON	JavaScript Object Notation
LMS	Load Management Standards (from the California Energy Commission)
MIDAS	Market Informed Demand Automation System
OCPP	Open Charge Point Protocol
OpenADR	Open Automated Demand Response
PG&E	Pacific Gas and Electric
PBGC	Price-Based Grid Coordination
PSPS	Public Safety Power Shutoff
RTP	Real Time Price
SCE	Southern California Edison
SEP	Smart Energy Profile
SGIP	Self-Generation Incentive Program
TOU	Time of Use
UNIDE	UNIfied, universal, Dynamic Economic signal
VPP	Variable Peak Price
XML	eXtensible Markup Language

1. Introduction

California is embarking on a process to accelerate incorporation of clean, renewable generation into the electricity supply. Senate Bill 100,[1] The 100 Percent Clean Energy Act of 2018, creates state renewable electricity goals of 60 percent by 2030 and 100 percent by 2045. This generation is mostly variable and nondispatchable, leading to increased curtailment of renewable supply, and costs from actions to fill in times when the supply and demand do not match.

The California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) have both identified dynamic prices as the central mechanism needed to coordinate flexible loads and other distributed energy resources (DER) with utility grid needs for balancing supply and demand of energy (CPUC, 2021a, CEC, 2020c). There is a need to explore the details of the technology infrastructure necessary for using dynamic prices to coordinate flexible loads. The purpose of this report is to describe that system, how to use the technology, and priorities for improving core technology communication standards.

The report is organized as follows:

- Section 2 reviews customer/grid coordination generally, with the concept of a "coordination architecture.
- Section 3 introduces "Price-Based Grid Coordination" (PBGC) as an architecture that can well meet the goals and objectives above.
- Section 4 presents the data model that implements PBGC for the data communicated among the various entities involved.
- Section 5 outlines a roadmap for evolution of necessary technology standards.
- Section 6 reviews policies and policy processes in California, principally at the Energy Commission and Public Utilities Commission.
- Section 7 offers conclusions.

The report also includes appendices with further detail:

- Appendix A reviews System Design Principles that informed the design of PBGC.
- Appendix B considers how price communication intersects current California tariffs.
- Appendix C details features of existing technology standards for price communication and how they could be improved.
- Appendix D covers a variety of implementation details for effective use of pricing.
- Appendix E reviews new capabilities enabled by the architecture, including microgrid operation, local prices, and local capacity management.

[1] Senate Bill 100, https://www.energy.ca.gov/sb100.

2. Grid/Customer Coordination

Utilities have increasing needs to coordinate the operation of devices in customer sites[2] (mostly buildings) with the needs of the utility grid. Many methods, and many variations of these, are used today to do this, or have been proposed. They have diverse benefits for the grid and customers. We call these "coordination architectures" (CAs) (Nordman, 2019a). Section 3 presents the Price-Based Grid Coordination CA; this section introduces the concept.

Researchers have spent many years considering how to coordinate Distributed Energy Resources (*DER*[3]) in customer sites with the utility grid. This work includes efforts of the U.S. Department of Energy's Grid Modernization Laboratory Consortium (GMLC)—most importantly, two past projects (Interoperability and Grid Architecture[4]) and one current project (on the Energy Services Interface).

Coordination architectures answer the question "who talks to whom about what?"; they specify the entities that are relevant to coordination, which communicate directly and which interact indirectly, and the types of interactions they have. The CAs also address the financial relationships among the entities and how the communication and device behavior affect them. Common CAs include direct load control, event-based demand response, critical peak pricing, variable peak pricing, time of use pricing, and aggregator-based systems. Proposed but rarely or never implemented ones include those with advance subscriptions, and complex 2-way transactive energy. Many of these have one or more disadvantages compared to highly dynamic pricing including:

- *Limited DER* - only a subset of DER in a building can be engaged (often a small subset).
- *Limited timing* - the frequency (how many times per year), time of day, or both are constrained.
- *Limited intensity* - the amount of DER response obtainable is fixed, or substantially less than completely flexible.
- *High complexity* - the information and computation required are high; this usually leads to higher costs and other disadvantages.
- *Shift only to later* - shifting of load can't be to an earlier time of day (when the grid may have excess power).

2.1 Highly Dynamic Pricing

A key concept in this report is Highly Dynamic Prices (HDP). HDP:

- Have a time granularity between hourly and five-minutes,
- Are announced no farther in advance than the day before, and
- Are different every day.

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[2] The term 'customer site' is used rather than buildings as to also include industrial, agricultural, and other non-buildings electricity use sites.

[3] The CPUC (CPUC, 2021b) defines "(DERs) include distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, time variant and dynamic rates, flexible load management, and demand response technologies. Most DERs are connected to the distribution grid behind the customer's meter (BTM), and some are connected in front of the customer's meter (FTM)." The CEC (CEC, 2020d) defines DER as "Assets connected to the distribution grid including generation, energy efficiency, electric vehicles and demand response." This project takes a subset of these: only DER within the customer site, only devices that consume or produce energy, and only those that change behavior taking account signals from the grid.

[4] https://gmlc.doe.gov/projects/1.2.1 and https://gmlc.doe.gov/projects/1.2.2

HDP are announced as a current price and future prices, usually for 24 hours but potentially several days. The future prices can be a guarantee or a forecast. The HDP term is mostly used in this report rather than the common term “real time price”, as the latter is commonly taken to be a narrow and rigid transference of today’s wholesale spot prices directly to the retail rate. While this is possible to do, it may well not be the best choice for co-optimizing the grid and customer interests.

New prices need to be sent to the customer site and its DER any time there is new price information. This could be once a day, for prices set day-ahead, or as often as every five minutes, as new prices are set. No financial arrangement is needed other than the regular billing.

3. Price-Based Grid Coordination

3.1 Context

As noted in the Introduction, California has ambitious climate goals, including for how its electricity grid is powered. To reach these, it will be necessary to harness the latent flexibility of usage inherent in many loads, to better match demand to the increasingly variable supply. Section 2 reviewed the most prominent of the mechanisms that have been used (or proposed) over the years to modify demand. All of these CAs, except for intensive use of pricing, have serious limitations on their potential for delivering this flexibility. As grid conditions on both the supply and demand side are different every day, to accomplish the flexibility we need, the prices need to be:[5]

- Different every day
- Set on the day of operation or the day before
- Have time periodicity between hourly and five minutes

We call such prices "highly dynamic" to distinguish them from those that are less dynamic and less granular (see Section 2). The focus of this paper is on communication needs for such prices. Obtaining the benefits of such prices requires three primary actions:

- Creating the retail prices
- Transmitting those prices from the retailer to flexible loads and other DERs
- Beneficially using those prices in modifying DERs operation

This report focuses only on the middle part — communication.

This system described here has simple but sweeping goals[6] for a system that distributes dynamic electricity prices to customers and that is:

- For all utility grid operators and energy retailers
- Universal and scalable
- Used in all customer sites
- For all DERs (within customer sites only)
- Supportive of locational prices

Such a system should result in wide-scale adoption, and reduce the costs and future curtailment of renewables.

Such a common mechanism for coordinating buildings with the grid also should be the same across the United States and internationally, as there is nothing unique about California's needs in this regard[7] — other than that we may need the solution earlier than most places. The best

[5] The first staff report for the CEC Load Management Standards process (CEC, 2020c) makes clear (page 2) that existing resources on the demand side are too expensive, too small, and too inflexible to meet the state's needs. It further states that prices need to change "at least hourly" and be locational, and be derived from wholesale market prices which are different every day. Wholesale prices include a five-minute granularity, and the report makes frequent reference to hourly, 15-minute, and 5-minute as likely time periodicities for rates. The CPUC in a staff proposal (CPUC, 2021a) noted that current approaches are scattered and inadequate ("complex, inefficient," and expensive) and that prices should be hourly or sub-hourly, and be set day-ahead or hour-ahead.

[6] These were taken from the project Scope of Work.

[7] Not having a common system would increase costs for consumers, utilities, and manufacturers. Appendix A includes extensive discussion of this, but as with other IT technologies, the existence of multiple standards has many drawbacks, particularly for product manufacturers who would have to support many different systems for doing the same thing in their products.

solution for California should be the best for many stakeholders, notably manufacturers, policy-makers, consumers, and the environment, and all of these benefit from a consistent solution. The reasons for this are reviewed in Appendix B, but two key points are that diversity in such a mechanism is costly for utilities, manufacturers, and consumers, and that it would lead to less load flexibility being accomplished.

The scope of this report is communication of prices[8] from a utility or other retailer to DER, or to other devices that make control decisions on behalf of the DER. It outlines but does not cover any final communication to the DER. It does not cover how prices are created, functional control protocols, or algorithms that use the prices. It is intended for all ordinary customers: residential, commercial, industrial, agricultural, and more.

Customer loads and the grid coordinate for a variety of reasons, and this discussion only addresses those aspects that are assessed by interval meters for billing — what can be considered **energy** coordination. Not included are issues around **power** quality (mostly involving only inverters) or potential future mechanisms for managing local **capacity** constraints.[9]

A few topics are out of scope. For example, some large customers may have needs beyond what the system described here will serve. These include billing for power quality burdens that the customer puts on the grid, participation in utility regulation signals (e.g., four-second up/down), and requirements around rotating outage participation. Utility grid needs related to power quality (as inverters commonly provide) are also beyond the scope of this effort. There may be an emerging need for a coordination mechanism to manage local capacity constraints on utility distribution systems, mainly due to electric vehicle (EV) charging, distributed solar generation, and building electrification. In line with the U.S. Department of Energy / Grid Modernization Laboratory Consortium (DOE/GMLC) principles for the Energy Services Interface (Widergren, 2017), direct control of individual customer sited DERs[10] by the grid is considered as outside of modern system design principles and is not considered here.

A key theme underlying the description below is that the system and communication involved should be as simple as possible, and no simpler. Complexity is costly across several dimensions. Simplicity is also needed for the project goals of scalability and universality. These same words appeared in presentations from CPUC staff in a May 2021 workshop on the future of DR: “Reduced complexity, single point of focus,” “Highly scalable, widespread adoption,” “automation.”[11] This to enable the ““UNIfied, universal, Dynamic Economic” (UNIDE) signal. The system described below is consistent with the goals of UNIDE for communication; that system does not address how to create the prices, which is part of the UNIDE concept.

3.2 Price-Based Grid Coordination

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[8] Also included is possible distribution of marginal greenhouse gas emissions, and a few nonprice grid messages such as impending power shutoff or a grid emergency.

[9] See Appendix E for a discussion of how local capacity management could be accomplished.

[10] In this report, DER is taken to include local generation, battery storage, flexible loads, and EVs. That is, it includes any device in a customer site that could usefully change its behavior in response to a grid signal.

[11] Advanced DER and Demand Flexibility Management Workshop. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-response-workshops/advanced-der-and-demand-flexibility-management-workshop.

The proposed system for grid/DER coordination is called Price-Based Grid Coordination (PBGC), since the retail price alone is at the center. The retailer may have complex systems for creating the prices (and forecasts), but those complexities are all hidden from the customer, who only sees the result — the price. Similarly, the customer as a whole, and/or individual DER, may have sophisticated systems for using the price, but these are all hidden from the grid, which only sees the result in changes in power levels at the meter over time. While all CAs have prices, they exercise them much less than, and with less effect than, with PBGC.

The goals of PBGC are well described in the project scope of work, as follows:

> Describe a candidate system architecture for interactions among the utility grid, buildings, and devices in those buildings, focusing on the information exchanged. Goal is to create a system which is unified, standard, simple, scalable, flexible, supportive of microgrids, and highly practical. Pricing in this case can be highly dynamic (e.g., hourly, 15-minute, or 5-minute), differentiated by customer or device class, and locationally different to respond to local grid conditions and needs. This will be accompanied by design principles, drawing on lessons from Internet architecture.

Over the course of this project, Lawrence Berkeley National Laboratory (Berkeley Lab) developed and refined the PBGC system architecture description for using time-varying prices as a control mechanism for informing customer DER behavior.[12,13] In parallel to this, the CEC made public a proposal for the upcoming Load Management Standards (LMS) update, and we found broad consistency between PBGC and the CEC model.[14] Similarly, the UNIDE proposal from the CPUC is also highly compatible with PBGC, though UNIDE delves into how to set the price, which PBGC does not. The differences are generally more a matter of emphasis and level of detail than actual incompatibility. Both models include the dissemination of marginal GHG signals in parallel to retail prices, so that customers can choose to take GHG impacts into account in the operation of their devices and decide how much weight to give to the GHG signal. Digital communication of prices is not itself new, though it is not widely used, as most customers have rates that vary only occasionally and/or in a highly predictable manner (e.g., TOU rates). PBGC has several new features:

- A clear articulation of the types or relevant devices involved, including where there can be a translation from a grid signal (price and GHG) to device functional control
- Clear identification of what occurs entirely within a customer site, to understand the implications when grid power, internet communications, or both are temporarily lost
- The concept of a "local price" of electricity,[15] which is useful for a variety of reasons

Figure 3-1 below shows a graphical illustration of PBGC, and Table 3-1 summarizes the key concepts shown. Note that Figure 3-1 shows all possible communication paths of information to a DER. Any actual DER will use only a single path from the price server to the DER at a time. Table 3-2 lists the possible paths in this diagram[16]. The orange lines in the figure show functional control commands sent after an entity other than the DER itself has combined the

[12] Note that there are both the generic model of using prices as the primary mechanism for grid coordination and its particular rendition as described here. In this document, PBGC covers both.

[13] There is also a Berkeley Lab project for Southern California Edison (via the Electric Power Research Institute), and some of this material has also been delivered to them in the course of that project.

[14] Information about the CEC proposals were made available in the summer of 2020 in meeting presentations and in the slides used for them, and in early 2021 a lengthy staff report on the LMS process was released.

[15] *Local* in this case is strictly inside of a single customer site. The concept is further discussed in Appendix E.

[16] The black lines carry prices and GHG (respectively), but that communication is outside of the scope of PBGC.

prices with functional operating considerations. Any of the four devices in the bottom half of the diagram can do the translation from price to functional control.

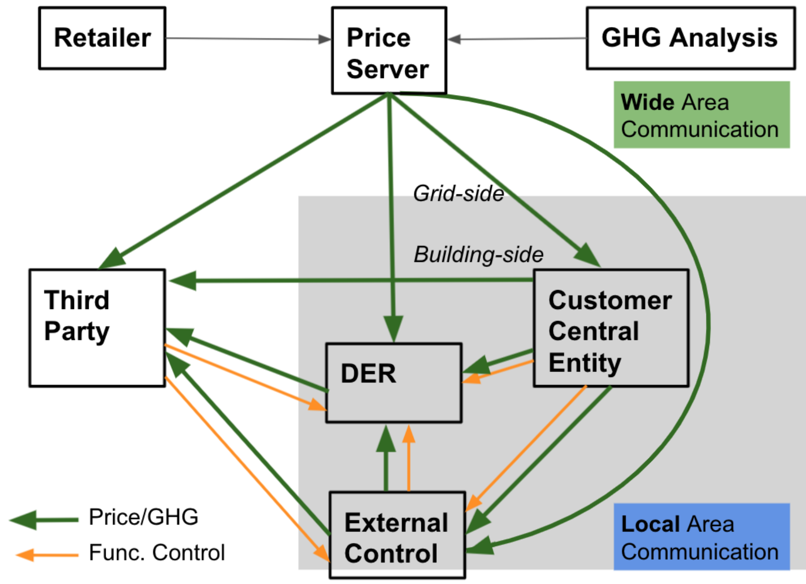

Figure 3-1. Price-Based Grid Coordination System Architecture

Table 3-1. PBGC Key Concepts

Entity	Description
Retailer	Organization that the customer pays for electricity service
Price Server	Device that broadcasts prices over multiple communication paths
GHG Analysis	Organization that estimates marginal GHG emission rates
Third Party	Organization outside the customer site(cloud-based) that provides the functional control commands to the DER, taking price into account
DER	Distributed energy resource within customer sites; it can include flexible end-use loads but also thermal or electric storage, dispatchable generation, and EV charging
Customer Central Entity	Device that takes in price information and distributes prices and/or functional controls to multiple DER
External Control	Hardware device directly connected to a single DER and that serves only one DER
Price/GHG	Current price and forecast of future prices, and corresponding marginal GHG emission rates
Functional Control	Device operation commands such as setpoints, on/off control, level

control, etc.

Note that the diagram and text refer to the price information as being strictly one-way. The current protocols for communicating prices — OpenADR, IEEE 2030.5, CTA-2045, and the new MIDAS system from the CEC — are all bi-directional protocols, though for pricing, no substantive information needs to be passed in the reverse path, so thinking of the communication as one-way or a broadcast is appropriate.

Table 3-2 shows the most likely paths that information might take as it travels from the price server to a DER. Most DERs will only use one path when installed at a customer site, but there is no barrier except for configuration complexity to allow for switching between multiple paths.

As part of this project, we have shared this architecture with many people in the course of many individual phone calls, webinars, and meetings. Examples include the Demand Response and Distributed Energy Resources World Forum 2020 in October, the Customer Grid Edge working group,[17] the Linux Foundation Energy's Spring Summit, meetings with staff from the California investor-owned utilities (IOUs), and standards meetings for OpenADR, IEEE 2030.5, and CTA-2045.

Table 3-2. Possible Paths from the Price Server to DER

Price Communication	Location of Intelligence	Functional Control Communication
Price Server >	DER	
Price Server > CCE >	DER	
Price Server >	CCE	=> DER
Price Server >	CCE	=> External Control => DER
Price Server > CCE > External Control >	DER	
Price Server > CCE >	External Control	=> DER
Price Server > CCE > External Control >	Third Party	=> External Control => DER
Price Server > CCE >	Third Party	=> DER
Price Server > External Control >	DER	
Price Server >	External Control	=> DER
Price Server > External Control >	Third Party	=> DER
Price Server >	Third Party	=> DER
Price Server > External Control >	Third Party	=> DER

Note: ">" designates a Price/GHG signal; "=>" designates a Functional Control command

[17] The CGE working group was long hosted by the Smart Electric Power Alliance but has very recently moved to being hosted by the Interstate Renewable Energy Council.

The core of price-based coordination is that the basic signal is one-way, sending prices from the grid to customers. There are return paths to the utility in the form of individual meter readings to compute the financial impacts of customer actions, and for grid management purposes, metering of feeders and substations. By only requiring the broadcasting of information, the overall system can be relatively simple — particularly when compared to what is required for systems with two-way communications and back-and-forth negotiations. The price signal is a current price and a series of future prices for roughly one day into the future, along with the estimated relevant GHG emission factors (Mandel and Dyson, 2017).

The communication in the system is to be standard, but the architecture does not specify or limit how prices are determined and how DERs use them, so these can be topics of innovation for utilities, product manufacturers, and others. The presence of the price forecast enables the algorithms to understand the benefits of any load shift or shed that the DER can accomplish. The model enables multiple locations of translating prices to functional controls. Examples of functional controls are turning a device or component of a device on or off to change a setpoint or operational level. A common translation of prices to functional control will be to change the device operation to shift some energy from high-price (and/or high-GHG emission) times to times with lower prices (and/or GHG levels). Functional control commands are sent today with a variety of communication protocols. PBGC does not change this.

3.3 Automation Pathways

Demand response works best when it is automated, and this is even more true for highly dynamic pricing than for most other coordination architectures. We can summarize the paths by the location of intelligence (as listed in Table 3-2) to create three broad “automation pathways.”

Figure 3-2 shows the overall system architecture diagram from previous task reports, annotated with three automation pathway overlays, to summarize the major approaches to automation that are likely to occur.

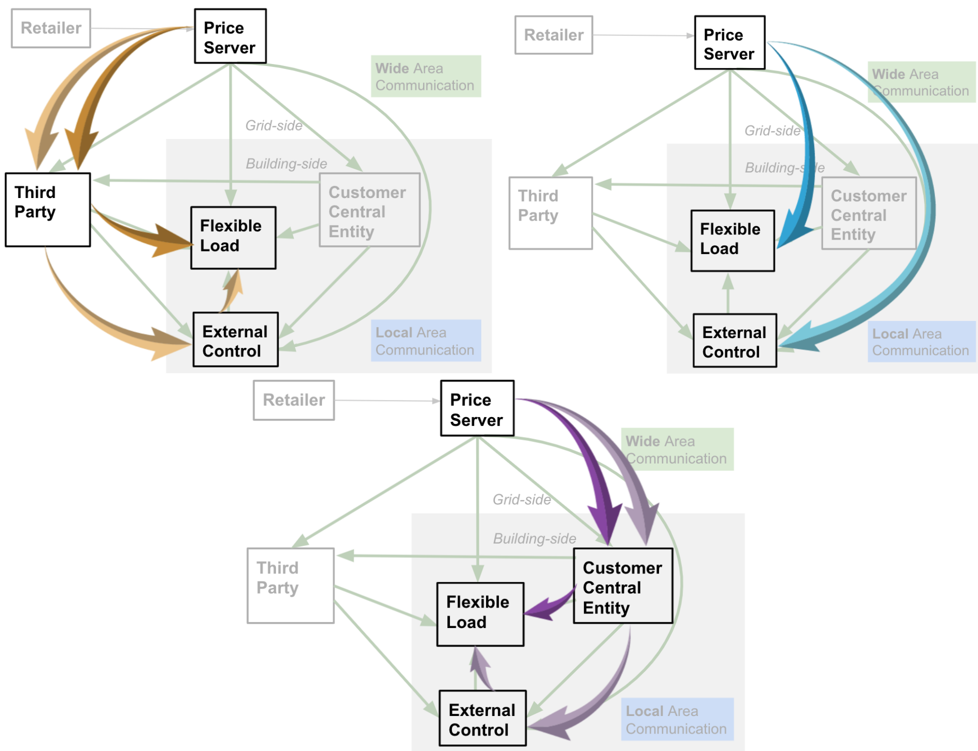

Figure 3-2. DR Automation Pathways (Cloud, Local, and Supervisory, respectively)

Table 3-3 shows the three major pathways — Cloud, Supervisory, and Local — with some alternatives for six sub-paths. One factor that creates sub-paths within these is how the price is received by building technologies.[18] With this in mind, we describe three primary pathways: Cloud, Supervisory, and Local.

Table 3-3. DR Automation Pathways

Overall Path	Sub-path	Comments
Cloud	Aggregator	Control via an entity with a financial relationship with the grid that is connected to the amount of DR delivered
	Third Party	Control via an entity that optimizes device operation on behalf of a customer and has no grid relationship for the flexibility delivered
Supervisory	Functional Control	Customer central control of device functionality, e.g., by a building / energy management system

[18] In one case, likely to be common, a third party receives the price directly from the grid and then determines the functional controls in its cloud infrastructure before sending those controls to the individual flexible load.

Local	Price Distribution	Customer central price distribution with control decisions made by device or external control
	Device Direct	Prices direct to device for self-management
	Via External Control	Prices to external control, which makes functional decisions

For the Cloud and Supervisory pathways, it is not considered significant whether the signal passes through an external control[19] device[20]. For the Local case, we do not distinguish between whether the intelligence is in the flexible load or the external control.

It may seem surprising that a third party would ever get the price from somewhere other than directly from the grid. However, there are some reasons this could be useful:

- When the third party receives the price directly from the grid, it needs to be informed what the customer's tariff is, and be updated when the tariff changes. Receiving the price from some entity in the customer siteavoids this.
- The applicable price for the flexible load[21] to use may be a "local price" set by a device in the building.[22]
- During microgrid operation, the grid price is not applicable (and perhaps not available) and so should not be used; the local price (see Appendix E) is the one that should drive flexible loads.

That said, for the foreseeable future we are likely to see third parties overwhelmingly get their prices directly from the grid, with the other pathway growing slowly over time.

3.4 Core Operation

PBGC is intended to be the simplest system that addresses the needs of both the grid and customers for managing energy flows over space and time. Key concepts in PGBC are as follows:

The data being communicated are a current **price** and nonbinding[23] forecast of future prices, along with GHG signals (e.g., marginal emission rates for a grid region). The prices are continuously "streamed" each time a new future price is available or a price changes; eventually likely at five-minute intervals. This is analogous to how Netflix streams movies, sending data on

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[19] In this report an *external control* is a hardware device that exists only to facilitate a single flexible load

[20] For example, a Customer Central Entity device might send a control signal directly to a DER, or to an external control which then sends it to the DER. That difference is not consequential for these pathways.

[21] Using dynamic prices to inform battery behavior is also intended, but as the great majority of devices that will use prices are flexible loads, we use just that term to cover the (slightly) wider full scope.

[22] Some examples of how this occurs are:

- The tariff includes differential buy/sell prices at the meter, so that the applicable price could be either, or something in between, and only known within the building.
- The tariff could be adjusted for a DC power domain or due to customer valuation of environmental signals.
- The grid goes down but internet connectivity remains, so that there is no applicable grid price.

[23] The future prices could be guaranteed; this is an option for the retailer to choose.

a continuous basis. It is even more analogous to live streaming of real-time audio or video content over the Internet.

How each electricity **retailer** determines prices is outside the scope of PBGC. Retailers generally have restrictions on rates they can charge, but ideally have latitude to select prices that co-optimize for customer and grid benefit. The price that is broadcast should be the marginal impact on the bill of consuming more or fewer kilowatts at that time and may not include bill elements such as fixed costs that are not affected by load shifting. That is, the purpose of the price broadcast is DER coordination, not formal tariff publishing, penny-perfect bill calculation, or settlement.

The retailer communicates the price to a **price server** that may also serve other electricity retailers and/or regions; a retailer may operate its own price server. A service provider estimates the relevant marginal GHG emissions.[24] The price server makes no decisions. The price server may broadcast the data over multiple physical layer technologies such as broadband internet, cellular radio, FM radio, and satellite.

The price may be relayed directly to individual DER (**price-to-device**) or to a customer central entity device[25] (**price-to-building**). For the latter, the price is then relayed to individual DER with an additional communication link. While such a **customer site"gateway" device** is not required, there are many advantages to having one. For a (potentially long) transition period, it will be easier for some DER to use price-to-device, including for customer sites that lack a suitable central entity device. Also for the transition, there will be many devices that cannot natively take in a price, so a control decision taking the price into account will need to be made by the customer central entity, a third party (such as a vendor's cloud), or an **external control** device such as a CTA-2045 module.

Third parties[26] can assist in control decisions. This is commonly a device manufacturer but does not have to be. Such third parties may get the price from the price server just as any customer does, or third parties could get the price from the device itself or from the customer central entity. These are different from "aggregators" in that they do not have a financial relationship with the utility.[27]

One important feature of this architecture is how it contemplates and enables "local prices." A local price is one that is specific to a single customer site, or a portion of a customer site. This recognizes that for a variety of reasons, the availability of electricity within a customer site can diverge from what it is at the meter. Only the meter price is used for cash exchange, but the local price can be used in DER decision-making to best reflect the customer's interests. The concept is further discussed in Appendix E.

[24] GHG signals are currently provided by WattTime, for multiple geographies (including CAISO), at five-minute intervals.
[25] It is labeled here as a "customer central entity" as the functionality involved can be hosted by a variety of different devices, and should be a function of an existing device rather than installing a new one only for this purpose. This could be a building or energy management system for a large building, or for a small one even a network device like a Wi-Fi router.
[26] Note that these third parties are not traditional utility "aggregators" in that they have no financial or contractual relationship with the utility grid.
[27] This does not preclude the possibilities of the third parties getting revenue from a utility, but that would not be the general case. They also might provide non-energy services valuable to the grid, and so coordinate with the utility for that purpose. Providing four-second regulation services is an example of this.

3.5 How Utilities Can Use Pricing

Price determination in general is beyond the scope of this discussion, but retailers should choose prices that best match their needs to align customer and retailer interests, while operating within applicable regulatory constraints. Prices should be locational, to vary by region, as utility grid conditions indicate. What size of regions might be used in the future is unclear, and could range from a large section of a major utility down to an individual feeder off of a distribution substation. Note that as used here and often elsewhere, “locational” refers to a portion of the utility grid. This is in contrast to the term “local” which refers to the inside of a single customer site; this usage is derived from IT systems that have a local area network that is generally coincident with the customer site.

Prices do not have to be the same for all customers, even those on nominally the same tariff. Customers could be spread out in time to avoid all having price changes at exactly the same time. This is most valuable for when large changes occur, as with TOU rates.[28] For more continuous RTP rates, such spreading may not be worth it.

[28] A real example of this is in France, where many TOU schedules have multiple peak periods with the start and end times shifted by 30 minutes (for example) to reduce the aggregate spikes that TOU rates introduce. https://www.genability.com/blog/france-rates.html.

4. Price Streaming Data Model

In the summer of 2020, Berkeley Lab created the data model discussed below to describe the information needed to transmit time-varying prices on an ongoing basis — to "stream" the prices. A version of it was embodied in the communication standard CTA-2045B; the update was ratified in October 2020. Static data fields change infrequently or never. Dynamic data are updated on an ongoing basis, ideally on a five-minute cadence, but also likely hourly, initially.

Static Data

RetailerLong - text string of retailer full name, e.g., "Pacific Gas and Electric."
RetailerShort - text string of retailer's abbreviation, e.g., "PGE".
RateNameLong - text string of rate name, e.g., "Residential Time of Use-A." This is unique to each retailer.
RateNameShort - text string of rate name, e.g., "TOUA." This is unique to each retailer.
Country - Alpha-2 code per ISO 3166-1.
State - Coding per ISO 3166-2.
Currency - per ISO 4217.[29]
DateAnnounced - ISO 8601 extended format,[30] "YYYY-MM-DD," e.g., "2020-05-26." This "publishing date" is particularly helpful if there is an update to the rate after the initial announcement. This is only a date, no time.
DateEffective - ISO 8601 extended format, as date/time.[31] This is the first date that the rate is planned to be available. No end date is specified.
URL – a web page with a description of the tariff in both machine- and human-readable forms. It should contain the current/correct tariff if there are multiple versions.
BindingPrices - True/false. True if prices are fixed once transmitted.
LocalPrice - True/false. True if the price has been adapted from a grid price by a customer siteentity, or created entirely locally (within the building). If left out, the default is false.

Dynamic Data

CurrentTime - ISO 8601 extended format, "hh" or "hh:mm" or "hh:mm:ss." Standard Time (not daylight saving time), including the time zone of the area covered by the rate.
OffsetToFirstPrice - ISO 8601 extended format, "hh" or "hh:mm" or "hh:mm:ss." Duration of time between CurrentTime and the first price in the sequence.
IntervalCount – number of intervals in the forecast, including the first price.

For Each Interval

TimeStamp - ISO 8601 extended format, "hh" or "hh:mm" or "hh:mm:ss," but not time of day, but relative time from the FirstPrice time. Allowed to go over 24 (but not over 99) to extend to more than 24 hours (note that this is likely not consistent with ISO 8601). Each timestamp must be greater than the preceding timestamp.
Price - numeric value of currency in text with appropriate number of digits. Price for purchasing electricity.
ExportPrice - numeric value of currency in text with appropriate number of digits. Price is for customers exporting electricity back to the grid. May be the same as Price, and assumed to be if "ExportPrice" is not present.

An example set of data following this data model, in the JSON encoding, is shown in Figure 4-1.

[29] SIX. Maintenance Agency. https://www.currency-iso.org/en/home/tables/table-a1.html, accessed May 26, 2020.
[30] Wikipedia. Calendar dates. https://en.wikipedia.org/wiki/ISO_8601#Calendar_dates, accessed May 26, 2020.
[31] Wikipedia. Calendar dates. https://en.wikipedia.org/wiki/ISO_8601#Calendar_dates, accessed May 26, 2020.

The specific encoding of the series of timestamps can reasonably be done multiple ways and translated unambiguously. The method shown here was created with the idea that the receiving device's internal sense of time might differ from the sending device, and that it will often be retransmitted; on retransmission the offset can be changed without changing each interval. The LocalPrice is not needed for wide area communication, and likely won't change DER operation, but is included for transparency, and for cases when a device receives prices from multiple sources.

The purpose of this data model is to facilitate full capability in, and interoperability among, communication protocols. It has been dropped into CTA-2045B in 2020. As of January 2022, it is in the process of being added to IEEE 2030.5. And for OpenADR, a consistent way of using the standard to encode this data has been proposed, and discussions are underway to consider adding it to the standard itself.


```
{
  "Static Data": {
    "RetailerLong": "Pacific Gas and Electric",
    "RetailerShort": "PGE",
    "RateNameLong": "Residential Time of Use-A",
    "RateNameShort": "TOUA",
    "Country": "US",
    "State": "CA",
    "Currency": "USD",
    "DateAnnounced": "2020-01-03",
    "DateEffective": "2020-07-16",
    "URL": "http://www.pge.com/tariffs/current/TOUA.html",
    "BindingPrices": false,
    "LocalPrice": false
  },
  "Dynamic Data": {
    "CurrentTime": "2021-05-06T09:55:30Z",
    "OffsetToFirstPrice": "0:04:30",
    "IntervalCount": 4,
    "Interval Data": [
      {
        "TimeStamp": "0:00",
        "Price": 0.15
      }, {
        "TimeStamp": "6:00",
        "Price": 0.3
      }, {
        "TimeStamp": "9:00",
        "Price": 0.15
      }, {
        "TimeStamp": "18:00",
        "Price": 0.1
      }
    ]
  }
}
```


Figure 4-1. JSON Encoding of Example Data in the Price Streaming Data Model
(Note: These prices were fabricated; they are not derived from a real rate.)

5. Technology and Standardization Roadmap

Technology standards enable any communication functionality, and those related to pricing are no exception. To move from today to a future in which highly dynamic pricing is widely used and highly effective at accomplishing shifts in DER energy use patterns, such changes will need to be made.

A first step is to gain wide acceptance of, and documentation of, the overall system architecture. The diagram in Figure 3-1 is one proposal for this. Others could be developed as alternatives, or modifications proposed to this one. How fast a consensus might emerge on this is hard to predict. Experience with internet technology may be instructive. Work on network communications that led to the development of the Internet Protocol began in the late 1960s, with formal work on what became known as the Open Systems Interconnection Reference Model in the late 1970s. The OSI Model was formally published in 1984. These are respectively analogous to price communication technologies and the PBGC model (Figure 3-1). That is, the formal model emerged and was ratified well after initial use of the core technology required, though that line of thinking certainly permeated the earlier discussions. For pricing, we already have some use of technology standards for price communication, even in the absence of an overall model, and will continue to develop those, so the comparison holds up. In sum, standardization of the PBGC model should be pursued, but not at the expense of work on the underlying technology standards.

The data model for PBGC could be considered analogous to other artifacts of internet technology, such as addressing, naming, and the domain name system (DNS). It also deserves standardization as a reference, possibly as an addendum to a standard on the system architecture it supports.

The core near-term activity is to define how to use each of the relevant standards in our price communication suite (OpenADR, IEEE 2030.5, and CTA-2045) in a way consistent with the price communication data model, to facilitate unambiguous translation among these. Updating these standards to more explicitly harmonize with the data model is the best way to do this, but takes time. This has already been done for CTA-2045, and consideration of this is advancing for the other two standards.

Further attention is warranted for how to evolve the standards to be more data efficient, e.g., to transition from XML encoding to JSON, and to reduce the transmission of redundant or unnecessary data.

Consideration should be given to if and how OpenADR and IEEE 2030.5 could be adapted for broadcast distribution rather than the fully bi-directional operation on which they are both based. What should be done specifically is not yet clear. There are many trade-offs and complexities, some of which are entangled with cybersecurity concerns. Both standards will continue to be used for other purposes that are inherently bi-directional.

Another approach is to streamline the installation and maintenance of DER in customer sites, e.g., to make discovery of local and wide area price servers automatic. The key here is not to create new technology standards, but to identify existing ones that can be leveraged for this application, and define how to use them specifically enough for manufacturers to put the capabilities into their products and have it “just work.” The price server discovery need is readily anticipated, but others may only become apparent after we have some actual deployment of products and systems.

Finally, there are technologies that are not strictly necessary for price coordination, but helpful for making it operate better. Two examples are energy reporting and user interface standards:

- **Energy Reporting.** This is the idea that in the long run, all energy-using devices should track their own energy consumption and be able to report that consumption over the network to a local device (or on an opt-in basis to outside of the customer site). This technology exists in some forms but needs further development to become broadly useful. This will help customer siteowners track the timing of their load consumption and be able to see if their pattern is as intended. For any device that can receive a price, this feature should require no new hardware and so be essentially free.
- **User Interface Standards**. As the controls for devices in buildings become more complex, it becomes increasingly important for the controls to be easily understandable to the humans that interact with them. A tool used in many application spaces is standards for user interface elements. Common examples are found on vehicle dashboards, phone keypads, and the like. A user interface (UI) standard for device flexibility could increase the flexibility we obtain and reduce user frustration.

More detail on Energy Reporting can be found in Appendix D

6. Relevant Policy Activities

While the focus of this report is the *technology* needed for price communication, the *policy* context is important in shaping the technology — and vice versa. In the last two years, California has become the global leader for innovation in, and thinking about, the widespread use of highly dynamic pricing. This section first reviews activities of the CEC, then addresses recent CPUC progress.

6.1 California Energy Commission

The California Energy Commission (CEC) has four major activities that intersect demand response and so (at least potentially) dynamic pricing. These are standards for appliance efficiency (Title 20), building efficiency (Title 24), load management (LMS), and appliances that can be flexible (FDAS). The sections below first review each CEC process individually, then evaluate how they do or could work together to support, encourage, or require comprehensive automation capabilities.

This discussion focuses specifically on automation and related topics that affect how automation is achieved.

Title 20

California establishes minimum energy performance requirements for appliances through "Title 20." While building standards (Title 24, see below) are promulgated as one document once every few years, appliance requirements are released on an individual basis[32] — Appliance Efficiency Proceedings.

Title 20's origin, and title, are energy efficiency. That is naturally the focus of all of its requirements. Demand response has emerged as a concern in recent years, and so consideration of how it might be added to existing or new Title 20 regulations is a live topic, being addressed by the Flexible Demand Appliance Standards proceeding (see below).

Heat Pump Water Heating

In 2020, the CEC added a new appendix, JA13, covering heat pump water heaters (CEC, 2020a). This did not create requirements for any water heater or any heat pump water heater, but rather for getting compliance credit for a "heat pump water heater (HPWH) demand management system ('System')". This is intended to "provide daily load shifting," which requires time-varying pricing or direct load control, as event-based demand response is intended to not be used most days.

JA13 allows for a "Remote Method," which includes ongoing communication to receive time-varying prices. It also allows for a "Local Method" without such communication. The local method is to enable automation of response to TOU rates, but precludes using rates more dynamic than that, e.g., CPP, VPP, or RTP. Regardless of which method is used, a complying device must support storing TOU schedules for at least three seasons, with the intent to make updating them usually required only annually.

[32] California Energy Commission. Appliance Efficiency Proceedings - Title 20. https://www.energy.ca.gov/rules-and-regulations/appliance-efficiency-regulations-title-20/appliance-efficiency-proceedings.

Functional control is specified as Basic Load Up, Advanced Load Up, Return to Standard Operation, Light Shed, Deep Shed, and Full Shed. These can be sent explicitly as direct load control signals, or price thresholds can be mapped to these control functions. Presumably DR events could also be mapped to the functions. The appendix states:

> The demand management signals may be sent from a local utility, a remote aggregator, a local demand manager (e.g., local time-of-use demand manager), or be internal to the System (e.g., internal schedule- or price-based demand management).

This corresponds to the retailer, third party, customer central entity, or DER in Figure 3-1.

A compliant system must implement at least one of three control strategies: time of use (TOU) control, advanced demand response control, or alternative control approved by the Executive Director. The first two correspond to the local and remote methods.

The bottom line is that systems can receive this credit, and possibly large dollar incentives, by allowing for only TOU optimization and not RTP. Those systems with communication that can support RTP of course can also support TOU. As such time as RTP rates are offered, the TOU-only devices will become obsolete. The customer will have a choice of optimizing to a flat rate or to the wrong price; two choices with bad consequences for the customer. If a TOU-only device has a CTA-2045 port that is unused, or is used for the TOU automation, then a new module could be added with RTP reception capability or the ability to receive external commands from a third party or customer central entity device. This would require substantial additional expense, and many units will remain without the correct optimization. An alternative would be to begin with only installing systems that receive continuous prices (the remote methods), even if for a few years they have TOU prices streamed over that communication channel.

Path Forward

The Flexible Demand Appliance Standards process should produce all the content needed to evolve Title 20. This should be a combination of generic content that applies to all or many devices, as well as content that is specific to one or a few product types.

Title 24

The energy efficiency of buildings in California is regulated through Building Energy Efficiency Standards (originally titled the Energy Standards). These were first adopted in 1978 and have been updated regularly since then. The standard (CEC, 2021a) is divided into three packages:

- A basic set of mandatory requirements for all buildings
- A set of performance standards for each climate zone and building type
- A set of prescriptive packages that provide a recipe or a checklist compliance approach

The 2019[33] updates of the standard were targeted to promote the achievement of California's Zero Net Energy goals; the 2022 update makes only minor revisions to the demand response provisions. The majority of the 2019 updates focused on the inclusion of photovoltaics into the prescriptive package and improvements for attics, walls, water heating, and lighting.

[33] California Energy Commission. 2019 Building Energy Efficiency Standards. https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards/2019-building-energy-efficiency.

Consistent with other definitions of the term *demand response,* Title 24 uses it to refer to electricity demand changes induced by dynamic prices or other means. A "demand response signal" is a price or a "request." The standard uses the term *demand responsive control* to refer to the ability of controls to respond to DR signals in an automated manner. An example of a device in a building that takes in DR signals is an energy management control system (EMCS). The standard also refers to a "home automation system" though it does not define the term.

Under the mandatory requirements for all buildings except healthcare facilities, the following requirements are listed for any demand responsive control (page 155/156):

> "1. All demand responsive controls shall be either:
>
> > A. A certified OpenADR 2.0a or OpenADR 2.0b Virtual End Node (VEN), as specified under Clause 11, Conformance, in the applicable OpenADR 2.0 Specification; or
> > B. Certified by the manufacturer as being capable of responding to a demand response signal from a certified OpenADR 2.0b Virtual End Node by automatically implementing the control functions requested by the Virtual End Node for the equipment it controls.
>
> 2. All demand responsive controls shall be capable of communicating with the VEN using a wired or wireless bi-directional communication pathway.
> 3. Demand responsive controls may incorporate and use additional protocols beyond those specified in Sections 110.12(a)1 and 2.
> 4. When communications are disabled or unavailable, all demand responsive controls shall continue to perform all other control functions provided by the control."

Of note, the 1.B requirement does not specify the mechanism for communicating between the device and the VEN. Presumably the manufacturer in this case identifies a specific brand/model VEN that is compatible with the device in question.

Other requirements that relate to communication apply to specific device types.

- "5. Demand responsive control **thermostats** shall comply with Reference Joint Appendix 5 (JA5), Technical Specifications for Occupant Controlled Smart Thermostats."
  The JA5 document (CEC, 2019) specifies that such thermostats must respond to both events and prices, with a "price threshold" triggering an event.
- "Zonal **HVAC** Controls" must support a "demand shed" capability for event-based demand response. This requirement does not mention price response.

There are other devices covered, but their requirements are only about performance, not about capability.

Path Forward

While Title 20 and FDAS will address requirements for loads, Title 24 should address requirements for a Customer Central Entity (CCE) device. The nature of what a CCE should be required to support and when different customer site types should be required to have one needs detailed consideration. Possibilities include requiring one or more protocols to be supported for wide area communication, one or more for local communication, the ability to incorporate GHG emissions data into operation, and some support for controlling legacy loads. While a CCE device could receive energy reporting data, it is quite reasonable for a customer site to have that hosted by a different device.

Load Management Standards

The Load Management Standards process was defined in the act that created the CEC and is updated every three years. The current rulemaking formally began in 2020.[34] Moving to modern smart meters with interval recording capabilities was part of earlier LMS processes, as this is necessary to load management automation that is based on prices. A list of "representative items" in the LMS 2020 Scoping Memo[35] were in three major categories: rates, storage, and automation. The scoping memo does note that the CEC, CPUC, and CAISO should "develop a consistent statewide foundation" for new tariffs, including:

- "Standards for access to load management tariffs in a machine-readable format to enable automation of price response (pull)
- Standards for the communication of load management tariffs to devices (push)"

Thus, the need for automation is at the core of the current LMS process.

The LMS process has included four workshops to date, from January 2020 through August of 2021. In the first, in January 2020, CEC staff noted that "RTP automation options in the works – enable TOU, CPP response too"; that is, technology for automating highly dynamichi prices inherently supports other common dynamic rates, but the reverse is not true. This point is critical; TOU automation *only* supports TOU, but RTP automation enables all price structures: TOU, CPP/VPP, and RTP. A presentation from WattTime noted:

- "For device companies, biggest barriers are complexity, not cost
    - Software engineers are typically the most constrained resource at device companies
    - Simple, ubiquitous standards dramatically increase uptake"

An early 2020 report from the LMS Process (CEC, 2020c) defined a "real-time tariff" as one that "updates at least hourly" and is locational to "reflect marginal costs at the ZIP code [or secondary transformer] level." It further stated:

> "(2) Communications. Electricity providers shall publish all non-tiered, time-dependent rates using the January 2020 version of OpenADR 2.0b (IEC 62746-10-1 ED1), unless the CEC adopts by rule a later version."

For EVs, a CEC staff summary references OpenADR 2.0b and SEP 2.0b as core standards, along with OCPP (versions 1.6J and 2.0) and IEC 63110. These last two are EV-specific (and IEC 63110 is still under development) and only contemplated for use between an EV aggregator and an electric vehicle supply equipment (EVSE) device. The slides also reference EVSEs with "embedded metering," which applies if the financial reward for changing charging patterns is different from the ordinary pricing for the customer as a whole, which time-varying pricing is designed to avoid or at least minimize. The slides also reference ISO/IEC 15118, but this is only for use between the EVSE and the EV. Finally, the statement is included:

> "The market is evolving toward a shared vision where 'Any PEV can plug into any EVSE, anywhere, anytime and they are able to function without special effort…'"

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[34] California Energy Commission. 2020 Load Management Rulemaking. https://www.energy.ca.gov/proceedings/energy-commission-proceedings/2020-load-management-rulemaking.
[35] Draft Load Management Rulemaking Scoping Memo. https://efiling.energy.ca.gov/GetDocument.aspx?tn=231432

along with the promise of "global interoperability."

In March 2021 the CEC put out draft LMS language, which included that utilities must "develop rates based on marginal costs…and make them publicly available for access by customers and their devices." It did not address details of how they would be made available.

The presentation for the April 2021 workshop noted that there is an existing CAISO API for distributing five-minute GHG signals, used with the Self Generation Incentive Program (SGIP).[36] It also included XML examples of TOU prices with the MIDAS system and described the encoding for the 16-digit rate identification number (RIN), which includes the country, state, retailer, distribution utility, rate, and location. It shows the rate and GHG information being passed to automation service providers (ASPs) who then pass this information on to communicating loads; while this is possible, the more common case would be for the ASPs to make decisions about functional control and pass those on to loads.

Recently, the CEC has confirmed that the highly dynamic price information will be encoded with a close adaptation of the mechanism already in use by WattTime[37] to distribute GHG emissions data.[38] LMS documents have noted that customers can use the GHG data in their device for operational decision-making, but have not specified how. That said, multiplying the GHG value by an emissions burden factor (in $/ton) and adding it to the retail price is a simple and obvious way to do this.

Path Forward

The LMS process provides a solid foundation as a policy vision. However, it would be improved with more detail about how to communicate highly dynamic prices; the effort to date has been focused overwhelmingly on TOU price communication. Soon, the CEC Electric Program Investment Charge (EPIC) project for a Load Flexibility Hub will begin, and further developing the communications standards and methods for price distribution is part of the scope of work of this expansive project.[39] This should enable more collaboration between the CEC and researchers and standards organizations.

While a CEC-sponsored service such as MIDAS is very helpful in the near term, and may in the long term be used by smaller retailers, we can expect the large utilities to develop their own, to have control over this key piece of operational infrastructure. This would likely be then utilized by CCAs (community choice aggregation) in their service area, much as they provide billing services for them.

A simple REST API as exists for GHG from WattTime, and for the SGIP program, and is anticipated to be replicated for MIDAS, is a promising element of future standards. Defining this as part of a technology standard that is directly or indirectly validated by an international standards organization would be helpful. Pursuing this through OpenADR is a promising path.

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[36] The SGIP program offers several forecasts of GHG values (for 11 regions in California). http://selfgenca.com/

[37] There is an effort called Climate Trace for tracking GHG emissions more broadly. WattTime participates in/with Climate Trace.

[38] WattTime. Introduction. https://www.watttime.org/api-documentation/#introduction.

[39] CalFlexHub. Advancing dynamic energy management. https://calflexhub.org/.

Flexible Demand Appliance Standards

The Flexible Demand Appliance Standards (FDAS) process aims to move demand flexibility into the CEC's regulatory framework. This was enabled by Senate Bill 49 which provides the CEC the authority to set appliance standards that include flexibility requirements. This process was initiated after the LMS process, and to date has avoided wading into details of communication approaches and standards.

The CEC's initial summary of the process (CEC, 2020b) defines "flexible demand" devices as providing a service distinct from demand response. Common definitions of the DR term include both event-based and price-based DR. The centrality of pricing to the FDAS process can be found in a statement in the summary: "The flexible demand appliance standards may include communication protocol requirements so that appliances can respond to grid conditions, price signals, or GHG emissions content of electricity supplies or a combination."

Path Forward

The FDAS process should create content that can be embodied into Title 20 requirements. This should be a combination of generic content that applies to all or many devices, as well as content that is specific to one or a few product types. Requirements should specify which specific technology standards are acceptable for being flexible, and what features of each standard need to be supported. How devices use the price data for flexibility will generally be a proprietary algorithm which incorporates functionality concerns, so in the near term is likely to be best addressed by standard tests that subject the appliance to a set of common example price shapes and report the results.

6.2 California Public Utilities Commission

The CPUC's most recent action in this area was a May 2021 workshop (CPUC, 2021a). An Energy Division presentation in that workshop cited the "unified vision" of a "unified, universally accessible dynamic energy signal and attendant system wide rate reforms." The "signal" in this case is probably intended to refer to the content of the signal — a dynamic price — rather than the mechanism for moving that signal. That said, universal mechanisms (even if more than one, but that are harmonized) are a natural follow-on. Most of the presentations were about the need for and value of highly dynamic prices rather than the systems and technologies for distributing them. Part of the core presentation on the UNIDE (unified, universal, dynamic, economic) signal is to unify the current scattered collection of different methods that cover rates, wholesale market interactions, and distribution level solutions. The presentation cites the need for a solution that is "highly scalable" for "widespread adoption." Realistically in the market this means that the communications technology should be as simple as possible, and utilize as few protocols as possible.

The UNIDE presentation includes the following features, which correspond well to the architecture described in this paper:

- An entity that calculates the time-varying price ("price machine")
- A single statewide URL from which to access electricity prices for all customers, with an obvious name, to distribute the prices to each customer and to third parties ("third party service providers (TSPs)"
- A customer central entity ("House EMS")
- Intelligence inside of individual DERs

- Plug-and-play functionality for which the DER automatically discovers the correct price server
- "Localized" ("Local") prices to consider distribution system issues[40]
- Not supporting demand charges or tiered rates

The UNIDE proposal is less specific about communication pathways and does not address where the intelligence is that translates the prices into functional control.

The UNIDE proposal also references features beyond this architecture:

- The option for customers to pre-purchase electricity on a time-varying schedule. This can provide some bill certainty, with some schedule of prices determined in advance. Deviations from this for actual consumption, up or down, would presumably be at the actual price, so that this would not change the price broadcast, and so a choice to do this is disjoint from the communications architecture. In fact, such "insurance" could be provided by a non-utility third party — there is no particular reason that the utility needs to be involved. Such financial hedging is done with other resources.
- "Transactive features," to make agreements with the grid to buy or sell future electricity on a more continuous basis, rather than as a one-time activity, as with the base pre-purchase system.

While not a communications issue, UNIDE proposes to recover part of the system fixed costs on a variable basis rather than a fixed amount per kilowatt-hour regardless of the time and location. This introduces more dynamic range than an algorithm whose only variable component is the wholesale difference, and so presents a better value proposition for shiftable loads.

6.3 Pacific Gas and Electric (PG&E)

PG&E is proposing to test Pilot Rates for Commercial Electric Vehicle (CEV) customers (PG&E, 2020). It expects that electric vehicle service providers (EVSP) will change their systems to be able to take in prices from "PG&E's Pricing Tool and display the pricing to EV drivers." For automation, it states that "PG&E will communicate the dynamic rate each day to customers in machine-readable format and via a publicly accessible website" and later on mentions "a pricing communication platform that will publish and disseminate hourly pricing to customers and third parties via a website or an Application Programming Interface." It describes the system for distributing dynamic prices as the "price portal," and states that when the CEC's system is operating, the PG&E system would send its prices there also.

The utility is also proposing "an opt-in Real Time Pricing (RTP) pilot for Commercial and Industrial (C&I) customers" (PG&E, 2021a). The document speaks to representing prices "in a machine-readable format (such as the Open Automated Demand Response [OpenADR] format) and a format that can be posted on a web site (e.g., daily pricing table)." The latter would seem to be a more simple text version of the data. They will create "a web site for customers and third parties to manually retrieve prices, and an API for machine-to-machine automation." PG&E plans to coordinate with the CEC (MIDAS).

[40] "Locational" is a better term for variations by location within the electricity grid. This is distinct from "local" as used in this paper for prices that are specific to the customer site or a portion of it, and may diverge from the grid price at the customer meter.

PG&E is also conducting a research project to test sending out custom price streams, that include the correct marginal price, taking into account a variety of tariff modifiers as well as where the customer falls in a tiered rate tariff (PG&E, 2021b).

6.4 ENERGY STAR

The ENERGY STAR Connected program, which recognizes devices that have communications features for energy purposes such as DR,[41] allows for all three automation pathways. The program to date has not been able to establish much in the way of technical requirements to guide progress, other than to require open standards either at the device or in the cloud. It does recognize the concept of a *customer central entity* with the smart home energy management system (SHEMS) specification.

6.5 The Retail Context

The concept of *prices to devices* has been around for many years, but there has always been the lingering question of which comes first: the price or the device? With any sort of dynamic price it is possible to use manual control, simple timers, native device delay or scheduling capability, or general behaviors to shift load — even without market availability of devices that can automatically take in and use such prices. However, if there is no dynamic price, then any behaviors and any devices are useless. Manufacturers understandably do not want to introduce features for which there is no market and that they have been unable to test against. The simple conclusion is, the price must come first.

6.6 Utility and Regulatory Issues

One issue which relates to this is "bifurcation." This is a principle, outlined in a CPUC decision (CPUC, 2014) to clearly separate those demand response mechanisms that are active in the CAISO wholesale market from those that are not. The latter includes retail pricing, both time of use and more dynamic forms, such as real time pricing. The reason this is relevant is that aggregators participate in wholesale markets, while pricing is strictly retail, so mixing the two at a single customer site could run afoul of the bifurcation principle.

Over the past two years, we have seen increasing interest and support for using dynamic pricing for customer / grid coordination at both the CEC and CPUC.

Utility tariffs have many purposes, the top of which is revenue collection to fund utility operation. A core principle of utility regulation is to tie tariffs to the underlying costs, as a basic matter of fairness. The ways this has been done has of course been shaped by the technology available at the time the tariff features were introduced.

Another purpose of tariffs is to encourage or require changes in customer behavior in electricity consumption patterns. The ultimate rates then become a control signal. With automation, time-varying rates become a means to actively (but indirectly) direct the operation of devices in customer sites. The reality of utility prices as a signal leveraging today's technology is different from that which existed when many rate features were created. This means that features which

[41] The ENERGY STAR refrigerator spec provides an example: https://www.energystar.gov/sites/default/files/Refrigerators_and_Freezers_Program_Requirements_V5.1.pdf.

were meritorious when they were introduced may not be so today, and some that were less worthy then, or even feasible, may now be superior.

With the prospect of significantly more dynamic prices, some people raise the spectre of retailers sending out prices which cause system instabilities, e.g. by alternating between a price that is too high and one that is too low. Such behaviors should be easy to avoid. Organizations will begin with making small changes in price and observing the result, and move to incrementally larger changes, and if the result causes too much of an effect to then back off. As time periods become smaller, the price difference between each will similarly decline, allowing the load to become more finely shapeable. In addition, as more storage is added to the system, it is not necessary for supply and demand to exactly match, though the degree to which they do reduces the costs (capital and operational) of that storage.

One reason there are so many approaches to coordinating DERs is that many solutions are designed around specific business models. Some business models are advantageous for individual vendor companies (that own the necessary "platform" technology) or current utility business models. Discussions about DER coordination are often muddled, as they commonly mix many disparate grid services that are really distinct problems, and/or propose to mix retail and wholesale markets. The problem of how to best coordinate customer DERs with the grid has been compounded by the long history of most utility customers paying flat or nearly flat rates, even as utilities have known for many decades that the value of the electricity they sell varies considerably over space and time. While "aggregators" do perform useful services in marketing flexibility to customers, creating and distributing enabling technologies, and documenting results for utilities, they also exist in substantial degree to work around retail rates that fail to accurately convey to customers the true value of electricity to the grid; in particular the value of shifting load across time in the course of a single day.

Many grid coordination mechanisms can work at cross purposes. Demand charges in particular can lead to complex building operational decision-making and behaviors that often do not benefit the grid, or even work against its interests. They also create great complexities for device manufacturers. The presence of aggregators also introduces complications and complexities, as the metered electricity includes both customer-controlled equipment and devices controlled by one or more aggregators, so they need to be disaggregated for the retailer to properly allocate costs and other financial details.

6.7 Greenhouse Gas Emission Optimization

A priority for the CEC has been to ensure that customers have the easy option to take greenhouse gas (GHG) emissions into account in the behavior of their DERs. To facilitate this, the CEC plans to broadcast marginal GHG data from its Market Information Data Analytics System (MIDAS) (Shepherd et al., 2021). Other coordination architectures do not facilitate simple customer-controlled integration of a GHG signal, but dynamic pricing does trivially, with the concept of a local price (more on this in Appendix E).

7. Conclusions and Next Steps

There is a great need to engage the potential of demand flexibility in customer sites to enable higher levels of renewable energy integration onto the grid, and to reduce capital and operational costs of running the utility grid. Using pricing to its fullest is emerging as a critical path forward to achieve this, in California and beyond.

This report reviews the variety of “coordination architectures” that are or could be used for grid / DER coordination. We present Price-Based Grid Coordination (PBGC) as a recommended model for bringing the widest range of DERs into being useful for utility purposes of balancing supply and demand. PBGC is founded on a data model and a communication system architecture that is highly practical, and can be incorporated into technology standards. We also include a discussion (Appendix A) of key design principles that informed its development. PBGC takes simplicity and universality as key goals. One notable innovation in PBGC is the notion of a “local price” of electricity.

The PBGC data model for communicating prices has already been incorporated into CTA-2045B and mapped into OpenADR. Coordination with IEEE 2030.5 is underway. The data model is not itself a protocol, but rather a way to ensure interoperability among diverse protocols by creating associated standard ways to map between protocols and the data model. Devices that use the data can focus on the data model to distill the essential information needed for coordination.

This report also includes a roadmap for how to evolve technology standards to support simple, effective, and consistent price communication, and recommendations for policy.

Overall, the interests of all major stakeholders in California appear to be converging to such a price-based system, so ramping up progress in the next few years is possible and can deliver substantial benefits.

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Appendix A. System Design Principles

Progress in evolving our electricity system requires integration of techniques from a variety of disciplines. Some questions are scientific, some engineering, some policy, and others are substantially ones of *design*. Given its name, it is no accident that “system architecture” is dominantly one of design. This brings in new dimensions and examples not found in problems that lack such a design focus. This appendix reviews some design principles that informed the design of Price-Based Grid Coordination, particularly those derived from internet architecture.

Automation

Many design issues relate to user interaction, as the presence of people in a system creates differences from systems that only involve hardware devices. To use pricing most effectively, coordination will need to be automated. We can design smart technologies with which people express or set general preferences but will rarely need to interact directly as prices change. These “set and forget” preferences may not require the user to have any direct interaction with prices. Ideally devices will have such good default preferences that most people do not need to change them at all. Rather, customers should be able to set preferences around building service needs or activity characteristics. An example of dynamic preferences is that a building as a whole and devices in it should know that the occupants are engaged in an anomalous activity, e.g., having a party, or on vacation, and so implicitly have different preferences. Another is for buildings to have high resolution sensing of occupancy to be able to best balance building services and the financial opportunities from adjusting energy use patterns.

A familiar example of automation is the anti-lock braking system found on most recent cars. Pumping breaks has always been possible through manual means, but many people fail to do it when needed, and few if any people can do the function as well as the automatic system. A simple thermostat is also such an automation system. Adding price response is most commonly just improving existing automation. Most devices that implement automation will have some default behaviors, which broadly work well for most people, so that many may not need to adjust the automation settings at all. This is similar to the high quality default behaviors found on most digital cameras, and now included in phones.

Design Principles and Simplicity

All design relies on some methods of approaching the problem and solution. Building architecture is informed by many factors, including system needs, thermal requirements for different climates, and structural engineering. IT system architecture, like building architecture, is created with a *design* activity. The system architecture for IT systems has been co-designed with technology standards for communication. Many concepts have been tried over the last several decades, with some proving more effective than others. From observing the trajectory of IT systems and the state of building technology, a number of principles emerge about technology in the utility grid, customer sites, and how they interact.

The first principle is to learn *appropriate* lessons from the success of internet technology. That is, do not take inappropriate models or conclusions. For example, because on the internet data are exchanged on a peer-to-peer (P2P) basis, it is often proposed that electricity exchanges on the utility grid be done the same way. On the internet, all data packets are different, so the P2P exchange makes sense. With electricity, all electrons are the same so that P2P logic breaks down, and an “Internet of Energy” makes no sense. Other adaptations that may be proposed in future may also not make sense.

Internet technology relies on principles such as simplicity and universality, and we can observe the salience of storage, the distinction between local and wide-area interactions (which map to retail and wholesale for energy), and “best effort” operation. Many principles of note map from internet technology (Carpenter, 1996) to energy systems:

- Simpler is better.
  - Complexity adds cost and introduces security and privacy risks.
  - Only add complexity when there is overwhelming evidence that it is needed.
  - Complex structures can be built on simple methods.
- Universal solutions are ideal.
  - Particularly for “retail” technologies (wholesale systems are a separate topic).
  - Universal is to span at least building and customer types and countries.
- We may be able to achieve needed levels of shift and shed in customer sites through prices alone.
  - Any remaining needs may not become clear until after pricing is in wide use.
  - We should only add mechanisms that we are certain we need.
- Storage changes everything.
  - Supply and demand no longer need to exactly balance.
  - However, the closer they are, the amount of storage needed to make up the difference is reduced.
    - This saves capital and increases energy efficiency.
- Retail customers should not interact with wholesale entities, other than the retailer who serves the customer.
- The technology for grid integration should be equally suitable for microgrid operation.
  - In both grid-connected and islanded mode.

These principles cannot in general be proved or disproved, but the technology systems that result from them can be compared to alternative proposals in their feasibility, costs, effectiveness, and implications for other significant concerns such as privacy, security, and resiliency.

Other principles have emerged to inform PBGC, though without an obvious tie to internet technology:

- In the long run, five-minute dynamic pricing, with a forecast for the coming 24 hours, is a likely endpoint.
  - With storage, it is unlikely that smaller time-steps are worth creating for retail customers.
- Many thermal loads optimize over a daily usage pattern.
  - They thus need day-ahead price visibility to best plan their operation.
  - Price forecasts are not guaranteed.
    - Like weather forecasts, they are “best effort.”
    - With today’s technology, both can be extremely helpful for decision-making.
  - Customers can acquire third party insurance if they want more price certainty or flat rates.
    - However, insurance always adds additional cost.

To summarize:

> PBGC is intended to be the simplest possible system that meets the needs of both the grid and customers. The approach in designing it was to only add complexity when it is abundantly clear that it is needed.

Why a Common Mechanism?

A subtext of this paper is that California needs a common mechanism for coordinating energy demand by customer sites with the grid. We can consider why this might be the case by considering if we had multiple different fundamental mechanisms in use, within California — and presumably more in other states — and more in other countries.

People move from place to place and so would need to learn to understand a different mechanism when they do, and sometimes do so when simply traveling. This places a burden on people and would likely reduce overall comprehension of how electrical systems work. When people move their household, they might discover that some of their appliances no longer work at their new location, as they were designed to only work in their original location. When ordering a device online, there would be a complex process to discover if the device that they want to use will work in their location or not. When people move their residence, they might discover that their new location uses a different grid coordination system, and so their appliances no longer work properly

With multiple systems in use, utilities might periodically decide to change their building/grid coordination mechanism works, which would cause large disruption and many stranded assets in customer sites, and likely significantly reduced flexibility until those assets turn over and can be replaced by ones that use the new system. Or, the burden of doing this would be so great that the pressure to stay with the current system would be overwhelming, despite the benefits of convergence. We see this often, as technological lock-in. The U.S. lack of using the metric system is one example; the different plug/outlet standards in Europe are another. These differences are burdensome for society and do not lead to any obvious benefit compared to a scenario where we had organized ourselves originally to use common mechanisms.

And perhaps the greatest issue is for product manufacturers. It can be challenging to persuade product manufacturers to include flexibility technology in their products at all. If they are told that they either need to support many different mechanisms in each product, for use in different electric utility regions, then the costs of including flexibility will rise substantially — with no obvious benefit to anyone. Design and manufacturing costs will increase, as will product support costs. Some manufacturers may choose to have market-specific models for each region, which would then increase their costs. It is well known that larger market volumes of devices reduce costs, and enable more sellers to successfully be able to operate at scale and so compete. Each different mechanism has its own design costs (hardware and software), but also its own cybersecurity issues. With multiple mechanisms, the burden of addressing these is multiplied, and likely this means less attention to each one, increasing the cybersecurity risk.

All of which raises the question of whether there is good reason to think that a flexibility mechanism that is the best for one region in California would not be the best mechanism for another region. Are there such differences between California regions that would lead to such a conclusion? If not, why would we do things differently when there are clear burdens to doing so?

Internet technology has shown the power of universal solutions. We all use technology such as email and web browsing that is fundamentally the same everywhere.

Appendix B. Application to Current California Tariffs

As a sample of what is used by California utilities, Berkeley Lab reviewed Southern California Edison (SCE) rates for residential and commercial customers and identified 17 rate “features” that are contained in the tariffs that are relevant for DER operation or otherwise significant to DER or customers. We then evaluated these for how they map onto a price-based coordination architecture and grouped them into four categories:

- Those that could be readily integrated into a price broadcast system
- Those that would require only a simple adaptation of the rate or system
- Those that are quite difficult or problematic to map onto a price broadcast system
- Those not relevant to such a system

These are summarized in Table B-1.

Table B-1. Tariff Features Found in SCE Rates

Directly Supported	Simple Adaptation	Difficult to Address	Not Relevant
TOU, CPP, VPP RTP Sub-Tariffs Eligibility Fixed charges Differential Buy/Sell Prices	Voltage/Phase Discounts	Tiers Demand Charges Combined Tariffs Bill Limiter	Direct Load Control Rotating Outage Reactive Power

Utility tariffs have many purposes, the top of which is revenue collection to fund utility operation. A core principle of utility regulation is to tie tariffs to the underlying costs, as a basic matter of fairness. The ways this has been done has of course been shaped by the technology available at the time the tariff features were introduced.

Another purpose of tariffs is to encourage or require changes in customer behavior in electricity consumption patterns. The ultimate rates then become a *price signal*. With automation, time-varying rates become a means to actively (but indirectly) direct the operation of devices in customer sites. The reality of utility prices as a signal leveraging today’s technology is different from that which existed when many rate features were created. This means that features which were meritorious when they were introduced may not be so today, and some that were less worthy then, or even feasible, may now be superior.

It is unavoidable that at some time (when is not clear) utilities will need to reconsider some rate features in use today, particularly tiers and especially demand charges. They increasingly work at cross purposes to greater integration of variable renewable energy into the grid. It seems likely that even greater rethinking of utility rate structures is needed, including consideration of lowering the marginal rate to encourage electrification (Borenstein, 2021) and to fund the distribution grid partly through revenue from other than electricity bills (Nordman, 2016).

Rate Design Options

The essence of enabling DR is having a "coordination architecture," which is the high level scheme of interactions of information, control, and money. Utility tariffs (and other DR programs if they are not part of a formal tariff) implicitly define a coordination architecture.

Table B-1 above identifies four types of rate features found in SCE rates as they relate to the PBGC model. In reverse order, these are as follows.

Not Relevant

Features not relevant to PBGC include direct load control (DLC) (it is considered a legacy approach for DR), rotating outage (only used for equitable response to emergency situations), and reactive power control (which covers power quality and not shifted energy). DLC can be phased out as utilities offer better dynamic rates to customers that address the same times of supply shortfall or high cost as DLC does.

Difficult to Address

Features such as tiered rates, demand charges, combined tariffs, and bill limiters are problematic when price is used as a control signal for DER, since it is difficult or sometimes impossible for a DER to correctly understand the cost implications of its behavior decisions, or for another entity (external control, third party, or customer central entity) to do the same. Demand charges are the biggest problem because at any given time, it is not clear what the effect on the bill will be, because it will generally depend on what happens during the rest of the billing period for the whole customer site. Tiered rates have the same problem, though the degree of uncertainty compared to demand charges is vastly reduced.

Simple Adaptation

Many California IOU rates include provisions for percentage discounts based on delivery characteristics (e.g., voltage, phase, or capacity) or customer characteristics (e.g., income level, location, or employer). These are generally simple percentages and fixed for a tariff and so change every few years or less. Therefore, they are easily addressed by any device in the system if not supported as a distinct rate.

Directly Supported

The last category covers features that are implemented directly by broadcasting prices or do not intersect the topic. For the latter, some tariffs are limited in who is eligible to sign up for them, some have fixed charges (which do not affect DER decisions), and some are really multiple tariffs that are similar, but described as a group.

The rate feature of differential buy/sell prices at the meter is not used widely in California today, but it is plausible that it may become a common feature in the future. The price data model described in this report includes the option for retailers to charge rates that can change for each metering interval based on the net direction of energy flow during that interval (e.g., hourly, 15-minute, or 5-minute). This allows a device in a customer site (e.g., a customer central entity) that has access to that power flow status at the meter to determine the applicable rate at that time. This could be the "buy" rate (power flowing into the customer site), the "sell" rate (power flowing out of the customer site), or possibly some price in between, that keeps the net power flow close to zero. In this case, all other devices should be set to follow the price published by this device.[42] Another alternative is that a device such as a battery or EV may want to use excess solar generation that would otherwise be exported, but not consume so much as to require importing power to the customer site. In this case it can monitor the net flow across the meter and adjust the charging to keep the net flow across the meter for each period close to zero.

The rest of the features — TOU, CPP, VPP, and RTP — are just different types of patterns that can be used to structure how a rate varies over time (or in the case of RTP, implying no inherent pattern). These are useful in describing tariffs to humans, but machines need to only see a stream of current and future prices. Thus, from the perspective of grid/DER coordination, with PBGC, the differences among these are not important.

[42] At least one SCE rate, for CPP prices, includes a buy/sell differential, with customers who are net exporters of power during CPP times being paid the normal rate, not the CPP rate. Utilities in Hawaii also offer such rates.

Appendix C. Technology Standards for Price Communication

Harmonization with Existing Protocols

OpenADR, IEEE 2030.5 (SEP 2.0), and ANSI/CTA-2045 (formerly CEA-2045) are the most commonly used communication protocols for DER and DR. These standards have overlapping grid domains and functions. The new API defined by the CEC (MIDAS) is not yet a standard, but is usefully considered here also.

Most of the data model in this report was put into the CTA-2045B standard with almost no adaptation, so for the time being, no further effort is needed for that standard.[43]

A standard mapping of this data model to OpenADR was defined by Jim Zuber of Quality Logic. While OpenADR has always been able to carry dynamic prices, there are a variety of different ways this can be done, so for actual interoperability it is necessary to define a specific way to use OpenADR. Consideration has been given to how to integrate OpenADR and CTA-2045.[44]

IEEE 2030.5 is the third major communication standard relevant to pricing. It does have the ability to carry prices as well, though to express the full richness of the data model above will require some special usage to represent all of the data in a consistent manner. In addition, the Ethernet standard (IEEE 802.3) can carry a current price[45] for the power carried over an Ethernet cable.[46] This shows the principle that power can be managed hyper-locally — across individual wires.

Further MIDAS Detail

The CEC/OMS effort is broadly consistent with PBGC and the data model described in this report. The LMS process anticipates increasing use of time-varying prices, and describes elements of automation systems to facilitate this. It is understandably focused on the most near-term needs (principally TOU rates), though it anticipates the longer-term future with more dynamic tariffs. Some differences in terminology have no significance, e.g., referencing “Load Serving Entities” rather than “Retailers,” and “Automation Service Providers” rather than “Third Party” entities.

The MIDAS system created through the LMS process describes a rate identification number format, as shown in Figure C1. The data elements largely overlap those in the PBGC data

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[43] That said, CTA-2045 only defines communication between a module and the device it is attached to. It does not describe the external communication — from the module to another device in the customer site or to one in the cloud. Creating an optional standard for this is possible and would be valuable.

[44] OpenADR Alliance, OpenADR and CTA-2045. https://www.openadr.org/assets/OADR_CTA2045_Overview%20Webinar.pdf

[45] The signal has no forecast or other data, only a current price. It expresses the price as an index relative to a “nominal” price, determined by the device providing the power. No products sold today are known to use this feature, but doing so would only require new software — not new hardware.

[46] This price is not for the AC power domain in the customer site generally, but for the power on the Ethernet cable. If a PoE switch is AC powered, then the price should be higher on the cable to account for the AC/DC conversion loss. If the PoE switch is DC-coupled to renewable generation, then the price might be lower than that in the AC domain. If a switch is nearing its capacity limit for providing power, then it might raise the price to help balance supply and demand.

model. Both are intended to be applicable globally, with standard designations of country and state (region).

The RIN distinguishes between the distribution and energy supply companies. In general it seems sufficient to identify a single organization that is responsible for setting the price. The RIN is compact with a fixed length, but at the cost of less flexibility. The MIDAS proposal does not address some of the remaining parts of the PBGC data model, though of course it does not in any way exclude them. The PBGC proposal was crafted with some thinking about how it might be encoded in communication protocols.

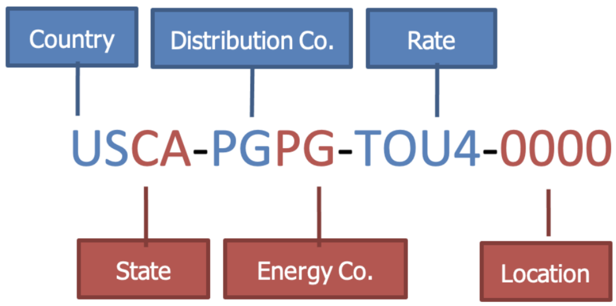

Figure C-1. CEC MIDAS Rate Identification Number Format (Source: CEC, 2020c)

The only graphic in the February 2020 CEC LMS report that is comparable to Figure 3-1 of this report is shown in Figure C-2. In part this is to address the question of how a customer or a third party knows the correct RIN to use. However, from this it is clear that sending prices directly to individual customers is not seen as an immediate goal of the CEC system.

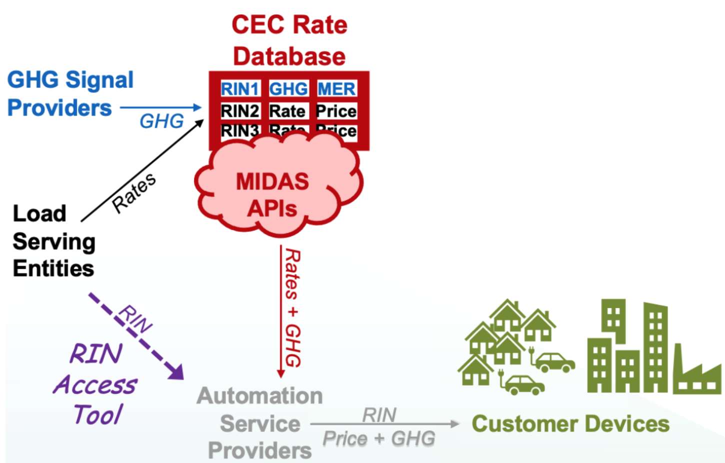

Figure C-2. CEC Data Flow Paths (Source: CEC, 2020c)

However, earlier diagrams from the CEC do make clear that sending prices to individual customers is the long-term plan; see Figure C-3.

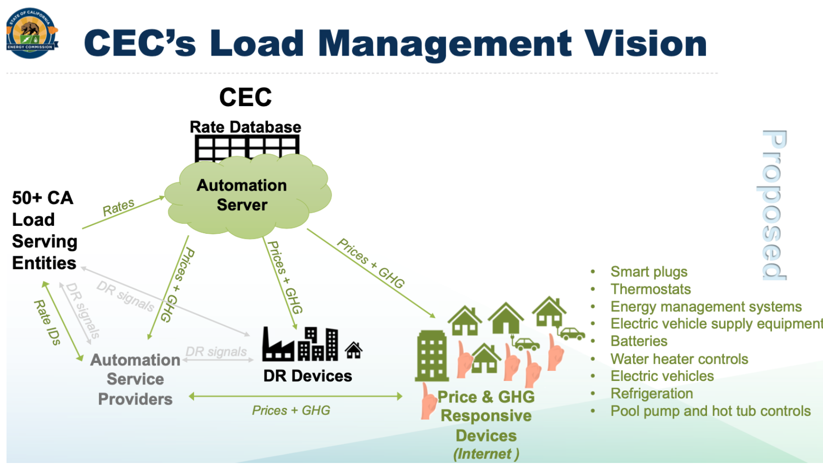

Figure C-3. CEC Data Flow Paths circa 2020 (Source: CEC LMS Overview slides, October 14, 2020)

Appendix D. Implementation Details

Price Server Names

The naming of price servers is in many ways a subset of the naming of computers on the internet, including web servers. This problem was addressed 37 years ago with the creation of the DNS, which translates names like `energy.ca.gov` to numeric IP addresses, and facilitates tree structures of names with the dot separation. We can apply DNS technology to price servers. It is a principle of internet architecture that if a solution to a problem already exists, do not create a second solution.

As an example, suppose that there is a server — `eprice.ca.gov` — for any price in California, and suppose a customer has PG&E as their utility and RESRT5 as the tariff. The customer could go to `eprice.ca.gov/pge/resrt5` and request the rate for PG&E and that tariff. Or, could go to `pge.eprice.ca.gov` and request the tariff,[47] or just go to `resrt5.pge.eprice.ca.gov` and get the current price without needing to specify anything else.[48] This would work whether everything was hosted on the same server or if there were subsidiary servers for each utility or tariff. As domain names are global, this readily scales to other states and countries, and to other forms of energy. The DNS system has security and redundancy capabilities that would be inherited automatically for this application.

Using DNS for this purpose is an implementation detail in the scheme of the overall architecture, but an example of leveraging powerful technologies already in use today for non-energy purposes.

It is not an accident that the examples above use the `.gov` domain name; this is controlled for who can create entries within it, unlike ones such as `.com` and `.org`. Commentators have pointed out that in cases such as voting information, it is possible for people to put up sites with fake information, but if all such sites were in the `.gov` domain and voters knew that, the potential would be greatly reduced. The same principle applies to electricity prices. Such a URL could lead to a non-.gov domain.

Device (DER) Issues

There are three basic ways that a DER device can be controlled to be grid-responsive. Figure 3-1 helps illustrate this in the ways that the grid signals reach the device (directly or indirectly). Figure D-1 shows a more traditional view of how to use OpenADR to coordinate DER in customer sites; these three paths map well to the automation pathways shown in Figure 3-2.

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[47] Note that we might encode the name of Pacific Gas and Electric Company as “PGE”. This is also a common abbreviation of Portland General Electric. However, since the California PGE is under the “ca.gov” domain and the Oregon PGE would be under “or.gov” then there would never be any ambiguity.

[48] The system could be further extended by adding locations within a rate, though the identity of a region with a distinct rate could be encoded in the tariff name.

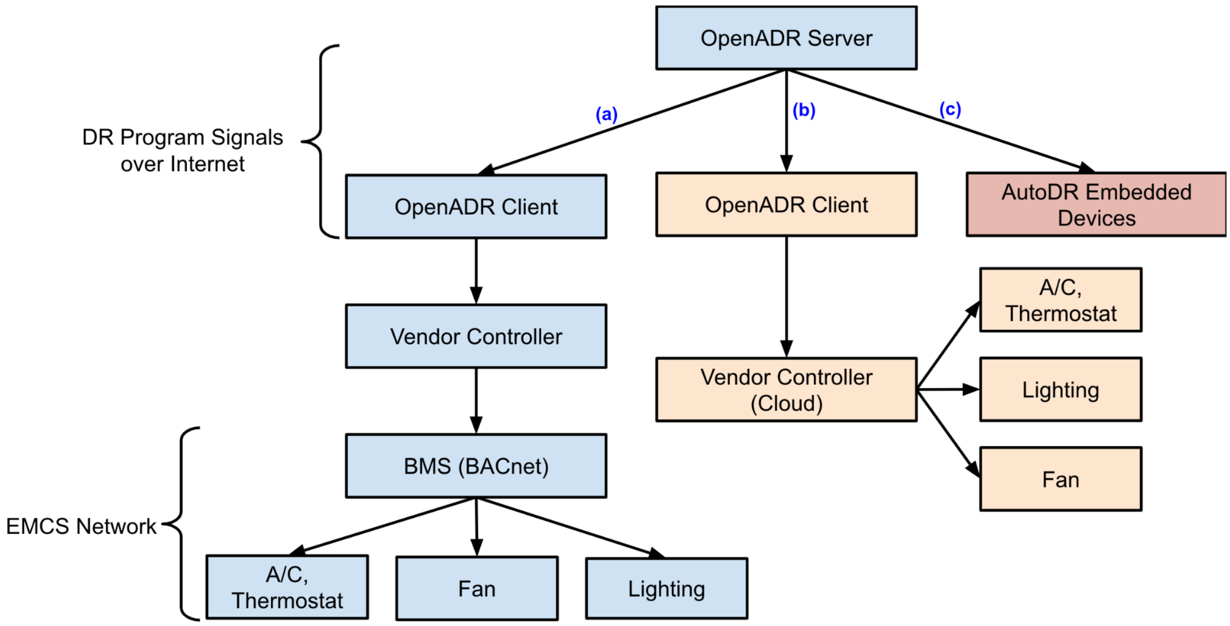

Figure D-1. CEC Data Flow Paths (Source: Rongxin Yin [Berkeley Lab], personal communication)

Natively Price-Responsive

These DER take in prices and act on them. The price signals can come directly from the grid, from a customer central entity device, an external control device, or a third party. The operative device characteristic is then the ability to receive price signals and productively use them (that is, operate in a way that is better for the customer in balancing service delivery with cost). While devices sold today that do this are few, they do exist, including a water heater from A.O. Smith and Ecobee thermostats. Some devices that lack this ability today can get a software update to add the capability.

Functional Control

These DER take in a digital communication signal or command (e.g., to change a setpoint), a service output level (e.g., light level, pumping rate), or even just on/off commands. These devices can communicate but do not natively support price response. The translation from price to functional control can occur in a customer central entity, in an external control device, or a third party service (usually cloud-based). The operative device characteristic is the ability to engage in digital communication about the device state or its control algorithm.

Some of these devices can receive a firmware update[49] from the manufacturer, in which case the manufacturer could add capability for price response to the device in the field. Many devices may have limited memory capacity so it is critical that protocols are available for sending prices that are simple to implement, as is leveraging existing protocols that the device may already implement, to only add use of the price feature. This of course requires the cooperation of the device manufacturer, and may require the device owner to initiate the update.

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[49] An example clothes washer currently for sale, the LG WM9000HVA, in its owners manual references a "Program Update" function to "Check to see if a newer version of the software is available." https://www.lg.com/us/support/manuals-documents.

Another type is a device that can take in functional control commands, such as to change a light level, a thermostat setpoint, turn on or off, etc. In this case, an external entity can take on the control logic for the device, at least partly. For example, a cooling setpoint could be driven by the relative price, to be driven down at low price times to precool, be at a "normal" setpoint for "normal" prices, then rise as the price rises.

A few devices will have a CTA-2045 port but either no module or a module that does not support price response. The existing module could obtain functional control commands from a customer central entity or a third party, or could be replaced by a new module that directly supports price response.

Direct Power Control

Direct power control involves selective depowering of the device to preclude it operating at times. Most commonly this is done with an external control. This will almost always be for devices that have no native digital communication capabilities. This may be appropriate for devices such as pumps that generally have no ongoing need for power, though attention needs to be paid to confirm this, as some devices may have sensors for detecting anomalous conditions that should get ongoing power.

For TOU rates, it may be suitable to use an inexpensive external timer (though daylight saving time changes and TOU timing changes need to be attended to), though for more sophisticated rates some computation about the rates and device needs is required. This can be done through a dedicated device, or a controlled outlet[50] or circuit breaker[51] that gets control signals from a customer central entity or a third party. A dedicated device will generally know what type of device it is controlling and so be able to act accordingly. An example device[52] monitors the electricity draw of the water heater it controls so it is able to understand heat added to the water tank, even as it does not monitor heat withdrawn through hot water.

In the PBGC architecture, there is clear separation between the utility domain and the customer domain. The utility needs to know nothing about individual DER or their control; it only modulates the price signal. Third party entities can provide sophisticated control, but as noted above these are not aggregators as they do not have a financial relationship with the utility (they could with the customer, but do not have to).

A utility could utilize aggregators in parallel with PBGC, though this creates complicated issues for fairly billing customers since some of their energy use is being controlled by a third party that has different and possibly contrary financial interests, and is being rewarded for changes in the operation of the aggregated device. That is, utilities need to be careful to not pay for the same energy shift twice.

A promising technology for customers is *energy reporting* (Nordman et al., 2019), which is the principle that devices in customer sites (including all DER) should keep track of their own

[50] An example controlled outlet (Wi-Fi) is: https://wyze.com/wyze-plug.html.
[51] An example circuit breaker (Wi-Fi) is: https://www.standardelectricsupply.com/Square-D-Schneider-Electric-M9F23206-Circuit-Breaker.
[52] An example dedicated water heater controller (Wi-Fi) with cloud-based computation is: https://www.shiftedenergy.com/technology/tempo-controller/.

energy use, and be able to report that locally to be available to customers. On an opt-in basis, select information from DER could be shared with researchers, utilities, or others, to inform our understanding of load flexibility.

Billing Considerations

Utilities have long had mechanisms in billing to insulate customers from the characteristics of new tariffs to also calculate their bill according to the old tariff, and either take the lower of the two or limit the amount of increase they see on the bill to some amount. The IOUs have “bill limiter” provisions in their rates, and some CCAs (e.g., East Bay Community Energy) have similar elements in their tariffs.

Appendix E. New Capabilities

While the core focus of this report is on engaging load (and other DER) flexibility with dynamic prices, to benefit the larger grid, the PBGC architecture also has other benefits in enabling new capabilities. Two of these are microgrid operation and local prices. Related to this is a potential capability for negotiated capacity management to benefit distribution systems.

Microgrid Operation

Under normal conditions, the California grid operates as a single interconnected system. One possibility for the future is for sub-sections of the grid — large and/or small — to be able to island from the grid as a whole, as a utility microgrid. In such cases, there may be a price generated within this islanded section, to balance supply and demand in the (potentially much) smaller context. CAISO prices may be unavailable, and also not especially relevant. Electricity could be more scarce or more plentiful in the microgrid than in the larger grid. Regulatory bodies as well as system operators and retailers should consider this possibility to make local or regional utility microgrids operable. The structure of price-based grid coordination readily facilitates this, though attention should be given to ensuring that customers and DER will always know the correct source from which to get the locational price from during islanded operation in case the locational price changes from the usual.

Even more likely is for customer sites to be able to island all or a portion of their own infrastructure from the grid — to create "single-customer microgrids." Today these are much more common than utility microgrids. Single-customer microgrids could make good use of locally generated prices to balance supply and demand in real-time, and to address potentially limited energy supply. As all the equipment is owned by the same individual or organization, there is no cash exchange with this use of pricing, and there is no issue with regulation.

Local Prices

The primary purpose of including the GHG signal in price broadcasts is to enable customers and their devices to take into account the environmental impact of their energy use patterns in DER control decisions. A simple way to do this is for the customer to decide what carbon cost (in $/ton) that they want to assign to GHG emissions, multiply that by the ton/kilowatt-hour (kWh) figure broadcast, and add it to the retail price. This creates a "local price" that more correctly reflects the true burden of the power. This does not change the price at the meter, but can change DER operation. This calculation can be done by any of the devices on the lower half of Figure 3-1, but is simplest to do one place, at a customer central entity.

Table E-1 shows an example pair of hourly prices for a building, along with corresponding GHG emission rates, and the economic burden of those GHG emissions based on a carbon burden of $100/ton ($0.10/kilogram [kg]). With this, what was a load shifting opportunity for strictly economic savings becomes a way to increase GHG emissions and so becomes unappealing to customers with this valuation of GHG emissions. Different customers will choose different GHG burdens, some much higher than this, and some may choose zero. Low valuations will lead to little effect on device behavior, but high rates could make a substantial difference. That said, to the degree that low prices and low GHG rates are already significantly correlated, this will have less effect.

There are other reasons to use a local price, such as to support differential buy/sell prices at the meter, microgrid operation, and more. The communication protocols that carry the prices do not have to know whether they are local, but CTA-2045 includes a flag for this, and a standard method for describing this in OpenADR has been identified.

Table E-1. Example Local Price calculation with GHG at $100/ton

Time	**Retail Price** *($/kWh)*	**GHG Emissions** *($kgCO_2/kWh$)*	**GHG Adder** *($/kWh)*	**Local Price** *($/kWh)*
Noon	0.18	0.5	.05	0.23
6 pm	0.20	0.2	.02	0.22

Some utilities in the United States, most prominently in Hawaii, already have differential buy/sell prices; even SCE has it in at least one tariff. With ongoing reconsideration of net energy metering, this may be useful in California. As an example, if a utility is selling power at $0.20/kWh and at the same time is buying it back at only $0.10/kWh, then the local price will depend on whether the customer is in buy or sell mode. Or, it may be that optimally it is doing neither, and a local price such as $0.15/kWh is the one that maintains that state.

When the utility grid goes down, there is no grid price, and any customer site that has microgrid capability needs to balance supply and demand locally — generally with at least photovoltaics (PV), battery storage, and flexible loads. While the scale is orders of magnitude different from grid operation, using price as a measure of resource scarcity applies equally to both cases, so it is natural to use pricing to manage microgrid operation. A customer central entity device (in this case operating as a microgrid controller) is needed to generate and distribute the local price. Using the same conceptual mechanism in both modes of operation means that the communication protocols can be unchanged and DER need not know or care whether the customer is grid-connected or not.

A further feature of local pricing is that it enables dividing customer electrical systems into multiple “domains” of power that can be loosely coupled to each other. A common example of this is when part of the distribution in the customer site is alternating current and part is direct current. Each domain can be independent, but they can exchange power with each other based on negotiations. Since one individual/organization owns both systems, there is no cash exchange involved in the use of a local price; the price is simply a unit of measurement useful for managing energy, just as with the unit of a kilowatt-hour. An electric vehicle (EV) connected to a building also is a separate domain of power (actually two inside the vehicle; one high-voltage for the drivetrain and one low voltage for most everything else). In sum, local prices can be used in at least the following circumstances:

- Incorporate GHG (or other) pollution impacts into device operation
- Microgrid operation
- Differential buy/sell prices at the meter
- Multiple power domains within the customer site(e.g., direct current domains)
- Electric vehicle charging and discharging
- Capacity constraints
- Battery management goals
- Managing local generation

Local prices can be used in any application context and in any grid context.

Local Capacity Management

While the scope of this document is generally limited to energy coordination, there is an emerging issue of managing hyper-local capacity constraints, particularly for how this is affected by EV charging. A pole-mounted transformer on a residential street may have a dozen or fewer customers supplied from it and many can be stressed by just a few simultaneous charging sessions, which will be increased as more customers move from Level 1 to Level 2 chargers. While increasing the capacity of local transformers and wires is always an option, this is expensive, and the peak charging periods would commonly coincide with systemwide peaks. This has two clear implications:

- Systemwide efforts to address peaks will have benefits for local capacity constraints as demand in general is more spread out across a day.
- Digital coordination to reduce very local peaks can reduce capital costs.

While price-based grid coordination relies on the load diversity of large numbers of devices and customers, hyper-local concerns lose that diversity. An alternative, only recently possible through technology advancement, is a permission-based capacity mechanism. An example of this is the following system:

- Each customer subscribes to a maximum nominal power capacity (in kilowatts over 15 minutes). This could be derived from their breaker panel capacity or historic usage. Overages would be penalized.
- The nominal capacity would be set to always or almost always be enough to power the customer site when EV charging is not occurring.
- Customer equipment would be able to monitor the total customer site consumption and consequently inform EV charging and/or battery behavior to keep the total consumption under this value.
- Customers could request authorization to consume at a higher power level for a defined period of time and power level. This would usually come with some fee, which would rise greatly at peak times.
- The capacity permission system would be in parallel with but not interact with the dynamic price system.

IEEE 2030.5 has a mechanism, “flow reservation,” that could be used for this purpose. If this were deployed, then it could be enabled on a customer-by-customer basis, so not everyone would need to upgrade their infrastructure at once.