Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework

Staff White Paper

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Introduction

California's electric sector is undergoing unprecedented change, brought about by a sequence of innovations in technology as well as many incremental policy actions taken in several different decision-making arenas. Between rooftop solar, Community Choice Aggregators (CCAs) and Direct Access providers (ESPs), as much as 25%[1] of Investor Owned Utility (IOU) retail electric load will be effectively unbundled and served by a non-IOU source or provider sometime later this year. This share is set to grow quickly over the coming decade with some estimates that over 85% of retail load served by sources other than the IOUs by the middle of the 2020s[2]. All this is to say that California may well be on the path towards a competitive market for consumer electric services, but is moving in that direction without a coherent plan to deal with all the associated challenges that competition poses, ranging from renewable procurement rules to reliability requirements and consumer protection.

In many ways, these changes are a function of California's success implementing world leading policies like the Renewable Portfolio Standard (RPS), the California Solar Initiative (CSI), and the Energy Storage Mandate. Through these policies, California's regulatory bodies and its IOUs have integrated renewable energy into the electric grid at massive scale, both at the transmission level through independently-owned large-scale projects and the distribution level through rooftop solar. This experience has empowered customers to choose new energy options and enabled new market entrants like Community Choice Aggregators (CCAs) to serve customers with innovative solutions. Though these changes have been largely positive so far, the consequence of fast-scaling competition is that the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) must now look at long held assumptions in their regulatory frameworks and examine the role of the electric utility at the center of this system, tasked with the primary responsibility for providing power and other services to all consumers within a geographic service area.

California's Changing Electricity Landscape

California has set itself on the path to reducing statewide greenhouse gas emissions by 40% below 1990 levels[3] by 2030, using tools such as a 50% renewable portfolio standard, doubling of existing energy efficiency savings for both electricity and natural gas usage[4] and putting well over 1.5 million zero emission vehicles on the road[5]. Achieving these goals will require enormous investments in the electricity sector, from widespread deployment of electric charging infrastructure to thousands of

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[1] Estimate of Direct Access, CCA and NEM retail sales offsets are 23% to 24% of Utility 2015 Retail Sales. For Direct Access, in 2016 ESPs served 12.9% of IOU Load (Direct Access Implementation Activity Reports). For CCAs, estimated retail sales are 7.4 GWh per CPUC Presentation at Feb 1, 2017 CCA En Banc. For NEM, 4,555 MWs of rooftop PV, per California Solar Statistics, April 19, 2017, with expected capacity factor of 15%-16% based on NREL PV Watts calculation of fixed tilt rooftop systems in San Jose, Los Angeles and San Diego. Other sources of NEM not counted for purposes of this estimate as rooftop PV accounts for more than 90% of NEM capacity per CPUC Net Energy Metering information page.

[2] Estimate of 85% load departure based on 15 to 20 million consumers being served by CCA, Direct Access or Customer sited generation like rooftop solar

[3] SB 32 (2016) requires California Air Resources Board ensures that statewide greenhouse gas emissions are reduced 40% below the 1990 level by 2030

[4] SB 350 (2015) requires the amount of electricity generated and sold to retail customers per year from eligible renewable energy resources be increased to 50% by December 31, 2030. Requires the State Energy Resources Conservation and Development Commission (Energy Commission) to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030.

[5] Executive Order B-16-12: Goal for CA to Deploy 1.5 million Zero-Emission Vehicles by 2025

megawatts of renewable energy, hundreds of miles of transmission lines and a much more robust distribution system.

Much of the policy framework underpinning the goals has presumed the electric utility serves as the central agent for making these investments, raising low cost capital in financial markets, and then recovering costs through sales of electricity. Yet, at the same time that California is grappling with how to plot a path forward to build this infrastructure in the most efficient, reliable and equitable way, the status quo retail electric service model is being up-ended.

Leading up to the new millennium, California de-regulated the electric industry and created a flawed retail market structure and rate design for consumer choice. Essentially, private electric utilities only provided wire and transmission services, and customers were expected over time to buy their electricity from third party companies. After a catastrophic collapse of the new markets, California made the conscious decision to return to the three IOUs as the dominant and monopoly providers of retail electric service for most California consumers, while continuing to restrict their ownership of sources of electric generation. As part of California's return to a regulated retail electric market, customers who had direct access at the time of the suspension were allowed to maintain service with their ESPs. A 2009 law (Senate Bill 695) led to a relatively small number of additional non-residential electric consumers being given the option to obtain their electric needs by ESPs. None of this had directly affected ongoing service by municipal and publicly owned utilities (POUs) who serve all customers in their service area with both electric and local transmission services. As a result, the three IOUs and 34 POUs have been the dominant parties on whom policy makers have relied as enablers of a number of key public policy initiatives, ranging from the procurement of renewable energy to providing low-income Californians with subsidized electricity.

Among the many new trends reshaping the California electricity landscape is the continued growth of net energy metering, largely driven by technology innovation and cost reduction in solar PV manufacturing and financing. Since 2007, over 4,500 MWs and 550,000 customers have 'gone solar'[6]. Programs like the Self Generation Incentive Program (SGIP) have furthered market transformation for additional technologies like fuel cells, thermal storage and lithium ion battery storage, allowing customers to produce their own power and /or to reduce their peak energy consumption. On top of these trends, energy efficiency programs and changes in California's economy have sharply reduced the growth rate in the use of electricity here.

One more recent trend is the growth of the CCA. Marin Clean Energy formed California's first CCA in 2010 and now serves 255,000 customers in Marin County, Napa County and the Cities of Richmond, Benicia, El Cerrito, San Pablo, Walnut Creek, and Lafayette.[7] Other active CCAs include Sonoma Clean Power, Lancaster Choice Energy, Clean Power San Francisco and Peninsula Clean Energy who serve a cumulative 660,000 customers[8]. Between all these communities, 915,000 customers currently take retail

[6] https://www.californiasolarstatistics.ca.gov/ as of April 19, 2017
[7] CPUC Staff Presentation at Feb 1, 2017 CCA En Banc-- http://www.cpuc.ca.gov/general.aspx?id=2567
[8] CPUC Staff Presentation at Feb 1, 2017 CCA En Banc-- http://www.cpuc.ca.gov/general.aspx?id=2567

service from a CCA[9]. This number is set to grow significantly in the coming years as cities and counties with populations in excess of 15,000,000 people consider launching CCAs[10].

This new set of developments fundamentally challenges the incumbent regulated utility business model, which depends on: a) borrowing large amounts of money to meet customer needs based on the expectation that IOUs are able to recover their investment through retail rates; b) maintaining highly reliable service at all times and for all customers; c) providing help to low income customers to ensure that everyone has access to basic electricity service; and d) providing quality customer service among other more traditional services.   Additionally, utility financing is increasingly being used to pay for new mandates that will help reduce California's greenhouse gas emissions, not just in the electric industry, but also in natural gas, transportation and natural land sectors, as well.

Much of the revenue to repay that borrowing by IOUs for the energy infrastructure Californians need to safeguard our future comes from a rate structure that depends on the volumetric ($/kWh) sales of electricity. When customers pay for electricity, they are paying for a vast network of connected infrastructure and services, from generation (from utility scale to rooftop) to energy efficiency programs to poles, power lines, substations and the many components of the grid beyond electric power generators that delivers it to California homes, businesses and industries. As sales by the regulated IOUs shifts to customers who provide for some of their own needs but still rely on the grid for various services, or to third party providers (like CCAs) of retail service, some portion of the many costs other than electricity itself may shift to the ratepayers who remain fully bundled customers of the IOUs.

But there is more at risk here than fairly apportioning costs or the utility business model: California's utility policy makers must address how these changes will affect our continued progress on our efforts to avoid and mitigate the impacts of climate change (and to do so in ways that sustain California's strong economy).   This emergent issue may be at the heart of the most important policy discussion regarding the electric industry in the last century.

This whitepaper and the upcoming 'Customer and Retail Choice En Banc' aim to frame a discussion on the trends that are driving change within California's electricity sector and overall clean-energy economy. The overarching goal being to lay out elements of a path forward to ensure that California achieves its reliability, affordability, equity and carbon reduction imperatives while recognizing important role that technology and customer preferences will play in shaping this future.

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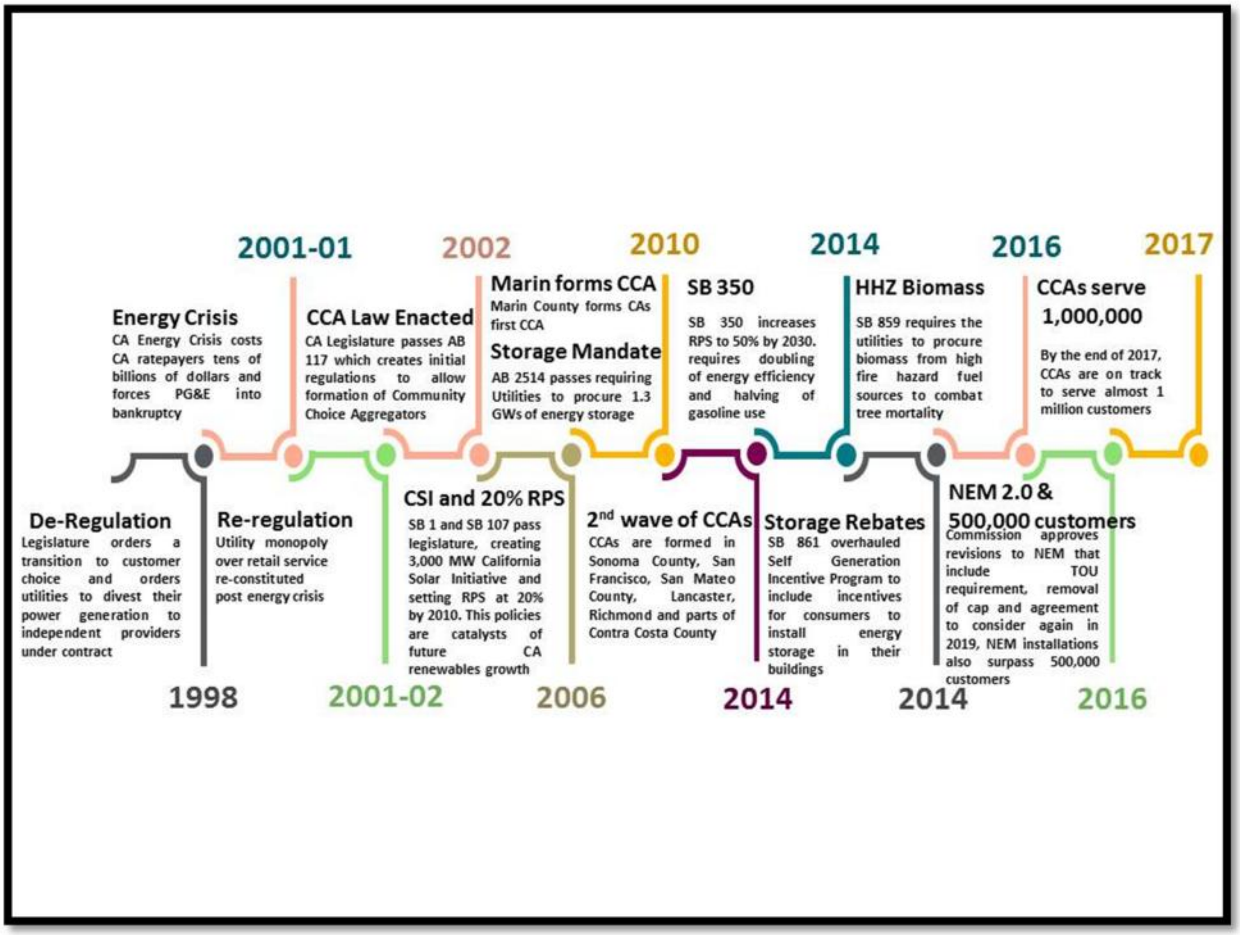
[9] CPUC Staff Presentation at Feb 1, 2017 CCA En Banc-- http://www.cpuc.ca.gov/general.aspx?id=2567

[10] Los Angeles County, Alameda County, Santa Clara County, City of San Diego, and City of San Francisco are all actively in the process of forming, expanding or considering the formation of CCAs. A number of smaller communities are also pursing CCA formation, including Hermosa Beach, Monterey, Salinas and Lake County. Cumulative population of these Cities and Counties exceeds 15,000,000 people according to census.gov.

Figure 1 - How did we get here?



The following section lays out a timeline of the major events that have occurred since the mid-1990's that have played a major role in the evolution of the retail electric market and describes the major regulatory efforts that are implicated by these changes.

Part 2 . Key framework policies affected by these trends:

Resource Planning

The annual process for planning for energy needs, including natural gas, petroleum, electric generation and energy efficiency, starts with the CEC's Integrated Energy Planning Report (IEPR), which establishes a ten year needs projection. The CPUC includes this in an annual Long Term Procurement Process (LTPP), setting a long range set of resource goals – taking into account legislative and policy direction such as the Renewable Portfolio Standard or AB 2514's storage requirements – for each load setting entity under the agency's purview. The CPUC also sets annual requirements for resource adequacy. The CAISO also uses the IEPR's forecast for its transmission planning process.

SB 350 established new clean energy, clean air and greenhouse gas reduction goals for 2030 and beyond. SB 350 requires the CPUC to (1) identify a preferred portfolio of resources that meets multiple objectives including minimizing costs, maintaining reliability, and reducing greenhouse gas (GHG) emissions (Section 454.51), and (2) oversee an integrated resource planning process involving a wide range of load serving entities, including the IOUs, CCAs and ESPs. SB 350 requires these LSEs to submit proposals for incremental procurement to satisfy their renewable integration needs. The CPUC is currently undertaking a proceeding to develop the rules that will govern the IRP process, including the level of oversight that the Commission will exert over resource portfolios. The CEC and CPUC are working hand in hand in this process, holding joint hearings and sharing modeling and analysis as needed, in order to develop a consistent framework that will also apply to publicly-owned utilities.

CPUC oversight of IOU procurement, through the legacy LTPP proceedings, has historically been extremely rigorous, with CPUC approval required for both resource need and individual contracts for resources that anticipate recovery of contract costs from customers. The challenge facing the CPUC in the implementation of the IRP proceeding is that as non-IOU LSEs serve an ever-greater percentage of load, the CPUC's top-down approach to regulation will be challenged by the need to interact with many more procuring entities. Further complicating the issue is the fact that there are outstanding questions regarding what role the CPUC has in the CCA IRP process.[11]. Depending on the resolution of these questions, issues of consistency and coordination between CPUC requirements and CCA independent authority could diminish the long-term effectiveness of the IRP process and could limit the state's ability to meet its GHG emission reduction goals.

These complications are also implicit in the limited CEC oversight of the POUs, who have generally developed procurement plans for their local service areas, but which has somewhat reduced the most optimal procurement and coordination of resources and utilization across the state.

Ensuring Reliability

The CPUC's Resource Adequacy (RA) program covers all CPUC-jurisdictional LSEs including IOUs, CCAs and ESPs. All LSEs submit load forecasts and the CPUC determines each LSE's RA obligations as

[11] See "Comments on Implementing GHG Planning Targets Staff White Paper" at www.cpuc.ca.gov/General.aspx?id=6442451195.

proportionate to their peak load share. The LSEs then submit annual and monthly filings to the CPUC to demonstrate compliance with their RA obligations.

When there is a need for procurement in order to meet a reliability need or a state priority goal (e.g., in response to the outage of San Onofre Nuclear Generating Station and the procurement of preferred resources to meet the need) the CPUC has ordered the IOUs to procure capacity and allocates the associated costs to all LSEs through the “Cost Allocation Mechanism” (CAM). The capacity benefits for these priority resources are also allocated to the LSEs as a reduction in their RA requirement. If significant numbers of bundled customers move to non-Utility LSEs, entities like CCAs and ESPs would make up the majority of the RA procurement requirement. This creates a number of new risk factors. These entities, without the traditional tethers to state regulatory bodies and statewide policy goals, might be less willing to utilize the RA program to advance dual reliability and public policy goals, particularly in emergency situations. This could create inequities across the body of consumers who benefit from and need to support the state’s economic and environmental goals, and could disrupt RA assumptions that must be commonly shared by all consumers of electricity from the grid. These issues of central planning and goal setting become even more critical as the grid becomes more variable due to the dynamic changes in generation from renewables, the need to focus on localized reliability instead of system reliability needs, and accommodating the increase in behind the meter distributed energy resources.

The CEC demand forecast is a foundational element of electricity system planning and procurement in California. The adopted demand forecast incorporates analysis of fundamental demand trends, impacts of distributed resources, and energy efficiency. To support distributed and renewable resource integration, the demand forecast is increasingly disaggregated, both geographically and temporally; future forecasts will be produced at an hourly level. The CEC forecast is a key input into the CPUC LTTP and resource adequacy proceedings, and the CAISO’s TPP and local and flexibility capacity needs analysis.

To support CEC demand forecasting, all LSEs in California, including CCAs and ESPs, are currently subject to data and forecast reporting requirements that vary in complexity by the size and type of the LSE. As nontraditional service providers expand and evolve, the data they provide to the CEC will also need to evolve to support demand forecasting that reflects the multiple trends affecting the timing and location of energy demand.

The California Independent System Operator (ISO) ensures reliable operation of the high voltage transmission system and infrastructure planning. Every year, the ISO conducts a transmission planning process that provides a comprehensive evaluation of the grid under the ISO’s control. The Transmission Planning Process (TPP) identifies upgrades needed to maintain reliability, successfully meet California’s policy goals, and projects that can bring economic benefits to consumers. The ISO’s TPP uses the same single forecast set as LTPP and the CEC’s IEPR. Efforts are underway to continue the agency process alignment under the CPUC’s IRP.

Ensuring All Customers Pay Their Fair Share

One of the most contentious issues that comes before the CPUC has to do with allocating costs between customers. For CCAs and ESPs, the CPUC relies on the Power Charge Indifference Adjustment (PCIA) to recover above market energy costs from customers who depart bundled service for ESPs or CCAs.

For CCA and ESP customers, the PCIA rate is set annually through the IOUs Energy Resource Recovery Account (ERRA) forecast proceedings. As the IOUs have procured increasing quantities of renewable energy, an increasing share of costs recovered through the PCIA are made up of the cost of the initial round of wind and solar projects procured through the RPS. These early, high-cost projects are often pointed to as one of the critical drivers globally of the major cost reductions that now benefit CCAs. Both the IOUs and the departing load parties have agreed that the current PCIA methodology is flawed. However stakeholders disagree on what changes are needed to ensure customer indifference and fairness.

For Self-Generation customers, IOUs rely on rates, including non-bypassable charges (NBCs), to recover broad infrastructure costs, as well as specific types of costs like low-income programs, and funding future de-commissioning of nuclear power stations. Each IOU calculates its own NBCs and applies them to all customer bills. When a customer self-generates, the IOU applies NBCs onto both electricity the customer buys from the grid and the electricity they produce and consume on-site. NEM customers have historically been exempt from paying NBCs on their solar generation, but with approval of NEM 2.0, a subset of NBCs are now going to be applied to NEM generation. Figure 2 below illustrates three examples of how NBCs are applied to PG&Es residential customers bills.

Figure 2 – PG&E Residential NBCs

	Residential NBCs	NEM 2.0 NBCs	NEM 1.0 NBCs
PPP	1.405	1.405	0
Nuclear Decommissioning	0.022	0.022	0
Competition Transition Charge	0.338	0.338	0
DWR Bond	0.539	0.539	0
Transmission	1.649	0	0
New System Generation Charge	0.255	0	0
Storage Mandate	0.045	0.045	0
TOTAL	**$0.04253/kWh**	**$0.02349/kWh**	**$0.00/kWh**

Setting the NBCs for NEM customers was a central point of conflict throughout the NEM 2.0 proceeding and remains contentious, with both the IOUs and consumer advocates arguing that NEM customers still do not pay their fair share transmission infrastructure they rely on. Whereas, solar advocates argue that the value of NEM systems to the grid exceeds the cost of NBCs.

For the broader set of infrastructure investments, IOUs recover their transmission and distribution (T&D) related costs from ratepayers predominantly through volumetric ($/kWh) rates. For larger customers, a portion of these infrastructure costs are recovered through demand based rates ($/kW). Under NEM, customers (particularly residential customers) are able to largely avoid paying any volumetric contribution to infrastructure costs – with the passage of AB 327 (2014), the CPUC can consider allowing a utility to collect a$10/month fixed charge for non-CARE customers. In the larger customer segments, energy storage systems – often subsidized by the Self Generation Incentive Program - are starting to be installed that allow customers to minimize paying demand based charges. The issue that both IOUs and consumer advocates raise is that NEM – and potentially energy storage – customers are not paying their fair share of T&D infrastructure costs. In contrast, solar advocates argue that the grid benefits of rooftop solar exceed the solar customer's share of infrastructure costs, and as a result all customers are better off. In an effort to find middle ground between these two positions, the CPUC mandated that all NEM 2.0 systems take service under Time of Use (TOU) rates that more closely align what a customer pays for T&D infrastructure with the costs IOUs actually to incur to serve them.

Allocating both generation and infrastructure costs between bundled customers and un-bundled customers is going to become more complicated as both business models and technology provide different forms of unbundling that each require different cost allocation solutions. The CPUCs task is to seek to continue to adjust rates and tariffs like the PCIA and NEM in ways to both allow customers to continue to make the choices they want while ensuring that all other customers are not left with an unfair allocation of costs.

Ensuring Universal Access

Currently, POUs and IOUs are the provider of last resort in their respective service territories. With changes coming to California's retail energy market, the CPUC must consider the implications of the changes for customers and evaluate whether a new 'provider of last resort' (POLR) requirement should be put in place. In retail choice states, POLR service (also known as Default, Basic Generation, or Standard Offer Service) is typically made available to customers who do not exercise their right to shop for energy. In all states besides Texas, the retail distribution utility holds the POLR responsibility. Even so, an overarching principle in virtually every jurisdiction with retail choice is that POLR's structure should not undermine the competitive retail energy market and should afford to customers the opportunity to provide quality, reliable, and transparent electric commodity service while also having access to non-discriminatory electric delivery service through the local utility.

One question which may need to be addressed is: which service – competitive retail or POLR service – becomes the default. This arises in consideration of whether non-Utility LSE service is an "opt in" or an "opt out" choice. Only Texas has adopted a retail-choice model in which all customers must still affirmatively decide which retail commodity supply is the one to provide them with electricity service.

Another issue arises from IOUs' historical obligation as the sole default providers of bundled retail service, for which they were required to make long-term investments in generation resources and long-term financial commitments through purchased power contracts. This has created (and if unaddressed may continue to create further) a cost legacy that must be addressed during a transition to retail choice. Most of the states that adopted retail choice have addressed legacy costs through the imposition of non-bypassable exit fees and/or continuing wires charges. The sizes of the fee have been controversial. Fees set too high undermine retail choice, while fees set too low enable departing customers to shift costs to those who remain on bundled service.

A third issue pertains to rules governing when and under what circumstances CCA or ESP customers are allowed to return to a utility's bundled retail service (assuming the utility continues to provide such service). If unchecked, one possible outcome may be customers taking CCA or ESP service when it is relatively less costly and to return to the utility when it is not. There should be clear rules about the conditions applicable to customer returns to utility service: when are customers allowed to return, how long they must they remain on utility service, what price must they pay for energy, and so on. As CCAs continue to grow quickly, the CPUC must consider how its current rules fit within a much bigger competitive landscape.

Rate Design

With the passage of AB 327 (2014) and CPUC Decision (D) 15-07-001, time-of-use rate structures are scheduled to become the default for all customers in 2019. The major goals of this requirement are to better align customer bills with the actual cost to serve and to provide customers with greater incentives to use electricity during off-peak periods when the grid is less strained and with lower costs to serve. AB 327 allowed the CPUC to require each of the IOUs to develop default time-of-use rates for residential customers, but did not authorize the CPUC to set such a requirement CCAs or ESPs. As a result, it is conceivable that the utility rates for bundled service will reflect time-of-use rates for all components of electric service, and that in cases where the utility only provides T&D service, this T&D component will be based on a time-of-use structure, while the generation component of the rate served by the CCA or ESP may not.

Non-participation in default time-of-use carries two major risks. The first one has to do with consumer protection. Currently, the vast majority of residential customers in each of the IOU service territories have the same basic rate design, incorporating both the design of delivery rates and the supply of electric commodity service. By contrast, customers taking service from CCAs and ESPs have rates that reflect the retail distribution rate design approved by the CPUC as well as the generation-service provider's non-CPUC regulated generation rates. This means that residential consumers in Pacific Gas and Electric's (PG&E) territory could go from effectively having the same rate everywhere – from Chico to San Francisco to Fresno - to having dozens of different rates based solely on where a customer lives. This is not *per se* a bad thing; the risk comes when the rates among CCAs or ESPs are more or less expensive based on factors like the consumer's income or where the consumer lives. Where variation arises due to customers' options for utility service, this seems like a benefit of competition; but where variation in pricing and rates for commodity service arises from customer profiling by location, it gives rise to concerns about discrimination and other problems relating to assurance of access to basic electricity services.

The second risk is that some CCAs will choose not to default their residential customers to time-of-use or that consumer confusion around applicability of time-of-use and hard-to-understand differences in time-of-use rates across communities that are served by both an IOU and a CCA will undermine the effectiveness of time-of-use pricing. Though the actual impact of time-of-use is as yet unmeasured, the hope is that the time-of-use transition will play an important role in supporting important grid integration and renewables growth policies.

Consumer Protection

In 1997, California Senate Bill 477 adopted consumer protections that, among other things, required that all ESPs offering electrical services to residential or small commercial customers provide proof of financial viability and of technical and operational ability as a precondition to registration. SB 477 also required the CPUC to develop uniform standards for assessing ESPs financial viability and technical and operational ability. In Decision (D.) 98-03-072, D.99-05-034, and D.03-12-015, the CPUC implemented these standards through its framework for ESP registration, with particular attention to concerns about residential and small commercial customers with peak demands under 20 kW. Subsequent CPUC decisions modified various provisions governing DA enrollment, customer switching, involuntary returns to bundled service, and ESP financial security requirements.

Similar safeguards have never been fully developed to govern new forms of customer choice, whether it be CCAs, rooftop solar installers or community solar marketers. That said, the market for these products is different than the services marketed by ESPs and so differing regulations may be appropriate. The CPUC currently is examining consumer protection issues as part of its on-going oversight of NEM. As retail electric choices expand, the CPUC will need to adapt its capabilities to protect consumers from predatory marketing, misinformation and fraudulent behavior. In California, competition in telecom and natural gas have demonstrated that the CPUC must have robust consumer protection programs, otherwise residential customers face risks.

PART 3 -- Expectations for the En Banc:

Given the strong evidence of profound changes and disruptions within the electric industry and its ratemaking/regulatory foundations, we seek comment and thoughts from a wide range of key constituencies on the following major questions:

1. As an increasing number of customers can obtain electric generation service from a variety of sources (including IOUs, ESPs, CCAs, and on-site technologies), how does California ensure that all customers get the benefit of having multiple institutions play an important role in helping finance the infrastructure needed to meet the State of California's GHG strategies, including electrification of transportation and fuel switching in the natural gas industry, while also ensuring that all customers have access to at least basic electric service?
2. What are the roles of the incumbent electric distribution utilities in the future, and what are the means for them to finance their core functions (e.g., distribution service, transmission service, POLR retail service) where some of these services are provided to all electricity customers and some are provided to only some customers (and in some cases may be provided because no other supplier is willing and/or able to provide them)?
3. Who will be the provider of last resort for customers who don't seek to make key decisions for themselves, but prefer a simple and reliable bundled service? What agencies are best designed to provide customer protection in this new electric industry structure? What policies and/or authorities are necessary for utility regulators (or others) to assure that all customers - regardless of their supplier of generation and/or delivery service) have access to reliable and efficient electricity supply that also supports California's economic and environmental goals?
4. How does the State of California ensure that the many different players work together to ensure that the State's electric supply is not only clean but is also reliable, efficient and resilient? For example in light of the changes underway in the State's electric system, how should the State provide such products and services as ramping power, voltage support, frequency control and managing over-generation? How should the State's electric system become more resilient (e.g., capable of fending off attacks from physical and cyber threats, as well as speedy recovery from disasters)? How will California's consumers pay for the many mandated public goods programs, ranging from energy research to providing energy efficiency upgrades and rate discounts for low income customers, which the California legislature has determined are core elements of the State's electric system?
5. How will the State of California provide protection for consumers against predatory actions by providers of electric service or energy technologies in these new policy settings?

The CPUC and CEC, as sponsors of the En Banc, will prepare and publish a report from the hearing, summarizing the range of comments on these key questions, and summarizing the insights gleaned from comments.

The CPUC intends to open a Rulemaking to examine, and coordinate among other open proceedings, an examination of the future role(s), structure(s), fiscal and other functions of the three large California electric IOUs. This, in turn, requires a discussion of the scope and scale of the current framework for regulation of competition – including customer centered technologies - and the structure of the retail electric market, and the transition from IOUs' responsibilities today and their responsibilities in the future. As part of this process, the CPUC will likely examine a variety of different retail market and customer choice constructs to assess what best practices and lessons learned can be applied in California given our unique set of public policy goals.

As part of this process, the CPUC will work closely with the CEC to coordinate efforts with the Integrated Energy Planning Report (IEPR) and the Energy Program Investment Charge (EPIC) program. Because of the interplay between the CPUC and the CEC on funding research (drawn from the IOUs based on their share of electric sales), and because of the CEC's role in setting overall electric need and overall procurement goals to meet that need, both agencies are both concerned about finding good and durable answers to these questions.

This effort necessarily implicates the ISO, as changes to retail market structures and the evolution of regulation will affect the transmission system and the wholesale power market. Furthermore, the same providers and technologies that are disrupting the retail electric market and the distribution system are also finding ways to participate within the bulk power system -- whether it be toward transacting in the wholesale market or offering alternative solutions to traditional transmission projects. To this end, this Rulemaking will seek to identify opportunities to harmonize market rules between retail and wholesale market and planning efforts between distribution and transmission infrastructure.

Finally (and as a fundamental framing consideration), it is critical to recognize that whatever the specific outcomes of this proceeding, it is very difficult to conceive of a scenario where the CPUC and CEC will not find that significant changes to the regulatory model and the utility structure are required. Drivers of change to the California electric system are accelerating whether we want them to or not. Technology will continue to advance and as a result consumers will have more options to meet their energy needs. Customers will seek to use these new developments to further their own needs and interests. California leaders and citizens intend to continue moving forward to decarbonize our economy, and the will to forge ahead grows stronger every day.