

11 June 2018

To: California Public Utilities Commission, Customer Choice Team

From: Ed Smeloff, Vote Solar

RE: Informal Comments on the Green Book, California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market

Introduction

Vote Solar would like to take the opportunity to offer comments on the Draft Green Book, “California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market”. Vote Solar agrees with the fundamental premise of the Green Book that California needs a coherent long-term vision and plan to address the State’s electric system requirements and environmental policy goals. The long-term vision and plan needs to address the challenges created both by technological advancements and by an increase in opportunities for consumers to make energy choices, including through use of distributed energy resources (DERs). It is crucial that California continue its role as a global leader in achieving deep decarbonization. The evolution of the state’s regulatory framework requires major change, largely to create alignment between utility shareholder interests and the interests of utility customers. Moreover, the regulatory framework needs to remain focused on new pathways to meet the existential challenge of climate change.

Sustained and Orderly Procurement of DERs to Achieve Deep Decarbonization

California has a long history of promoting policies that support the sustained and orderly procurement of increasing quantities of renewable energy. These policies, particularly the commitment to adopting an increasing renewable portfolio standard, have significantly reduced the costs of solar technology, in particular, and have begun to make the benefits of this technology more widely available to all classes of electric consumers.

A similar opportunity is now available for California to increase the use of complementary technologies including energy storage, electric vehicles and more

sophisticated demand response measures to further increase the integration of solar and other renewable sources of energy while supporting the reliable and cost-effective operation of the transmission and distribution systems.

Technological advances in solar and other technologies are creating opportunities for their use as DERs in ways that can lower the cost of delivering power by deferring most costly investments in the distribution system. In 2013, AB 327 was enacted which kicked off a multi-year Distribution Resource Planning (DRP) proceeding to develop processes and build shared information that is enabling distribution utilities and third-party technology providers to use DERs more effectively. The Commission needs to continue to build on the learnings from the DRP proceeding to better identify the optimal resources mix of supply-side and demand-side resources required to meet the State's long-term energy needs.

One of the processes that has been initiated in the DRP proceeding is the identification of location-specific distribution system impact values of DERs. Further refinement of locational costs and benefits is needed to inform procurement decisions by all load-serving entities, particularly Community Choice Aggregators. Vote Solar believes it is important for the Commissions to continue to advance this important work on Locational Net Benefits Analysis as it will create more informed choices by customers and more efficient energy markets.

Moving Beyond the Traditional Cost of Service Regulatory Model

The Green Book assesses aspects of electricity markets and regulatory policy in New York, Illinois, Texas, Great Britain, and California. In this analysis, the Green Book identifies an issue that Vote Solar believes is one of the most significant barriers to the deep decarbonization of the electric sector; continuation of a century-old regulatory model that encourages utilities to increase investment in traditional capital assets while discouraging independent investment in innovative and consumer-empowering technologies. Customer-facing technologies including, distributed generation, energy storage, electric vehicles and smart building technologies are disrupting the way that electric utilities have traditionally conducted their businesses.

Centralized power generation and transmission are now being supplemented with customer-sited energy technologies. These new technologies are reducing overall growth in electricity usage while creating needs for new types of electric grid services. Many customers are interested in using electricity in different ways than in the past and, in some instances, offering value back to the distribution utility.

A model for regulatory reform that the CPUC should investigate in more detail is the Hawaii Ratepayer Protection Act (SB 2939) that was recently enacted into law. This milestone legislation is intended to align utility ratemaking with the integration of increasing quantities of renewable energy. The measure requires the Hawaii PUC to establish customer-focused performance metrics including the timely interconnection of customer-sited resources including solar and battery storage, the execution of competitive procurements for supplemental power needed to maintain reliable service and modernization of the distribution system to accommodate two-way power flows. The Hawaii PUC has recently issued a white paper on potential regulatory policy changes to align customers' interests and the state's public policy goals with the utility business model.¹

California has had experience with performance-based ratemaking (PBR) which should be re-examined in the context of the power sector transformation that is underway. PBR design practices should focus on performance-based dashboards which embody metrics, incentives, and outputs that clearly align with California's overarching regulatory goals. To minimize the risk of gaming, the design of incentives should be clear, relatively simple to understand and developed through a broad stakeholder involvement process.

Vote Solar believes that well-designed PBRs can accelerate renewable energy integration, increase customer energy options and realign utility, investor and consumer incentives. Without reforms to the existing regulatory framework, it has been acknowledged by the Commission that misalignment between utilities' financial imperatives and the State's policy goals is likely, if not inevitable. Vote Solar is concerned about reliance on "command-and-control" approaches to achieve the States

¹ <https://puc.hawaii.gov/wp-content/uploads/2014/04/Commissions-Inclinations.pdf>

ambitious energy policy goals, much less the detailed needs of customers as we refine the use of grid tradeoffs and resource options. Currently, rate-base regulation provides extraordinary incentives for grid owners to spend more ratepayer funds on anything that grows the rate base. A more nuanced approach, which remains simple, is to use performance “dashboards,” which may include indicators based in investment efficiency, capital-cost reductions, customer bills, customer satisfaction, and use of third party innovation.

Utility Profits Based on Capital Expenditures

The Green Book asks specifically about, how to ensure affordability, decarbonization, and reliability. Vote Solar asks the Commission to focus on the parallel question posed and answered by Hawaii: should electric utilities continue to use rate-base rate-of-return regulation (RBROR), as it has for most of a century? The State of Hawaii has said no to this question for very important reasons. Key regulatory experts have explained that RBROR has endured because of the *end result doctrine*, which argues that it is not the method used to set rates but rather the end result that matters.²

Utilities have been subject to RBROR regulation as part of the *regulatory compact* with customers. RBROR has been used to ensure capital is available for this most capital-intensive industry. Utility earnings are based on the amount of (undepreciated) capital accumulated, an amount then multiplied by an authorized rate-of-return (ROR) to yield profits. Utilities have accepted the obligation to serve all electric customers in exchange for the franchise rights to serve at RBROR levels. This compact has aimed to establish prudent utility costs and provide incentives to maintain efficient services to customers. A host of *patchwork* regulatory policy and legislation changes have since occurred, though the RBROR compensation mechanism remains largely intact, incentivizing capital-intensive solutions.³

² Karl McDermott, Cost of Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation, Electric Power Research Institute, June 2012, at pg3; see also, *Hope v. FPC*, a 1944 Supreme Court case clarified that any method of regulation which results in an appropriate balancing of customer and stockholder interests is permissible.

³ Starting with the CPUC’s report, by Mark Ziering, Risk, Return, and Ratemaking (3Rs), Planning Division, October 1986, see, R.86-10-001.

This approach, however, has failed to provide incentives to utilities that are well operated and would otherwise choose less capital-intensive options. Compelled by new technologies, the changes desired by policy-makers dramatically alter the duties and responsibilities assigned to the utility. This change in duties and responsibilities suggests the need for changes in compensation. DERs promise to usher in the use of less capital intensive resources to defer the need for more capital-intensive generation, transmission, and distribution investments.

New Utility Duties to Integrate DER for Customers

The previous utility duties were to provide customers with electrical service and to make timely and prudent adjustments to ensure a reliable electricity supply system. The duties have now changed to require utilities to create opportunities for the use of DERs to integrate and optimize the use of renewables in an increasingly complex grid. With this new objective function to “integrate and optimize” DERs on the grid, innovations to drive technology adoption must move more quickly, at market speed. As utilities have been slow to embrace disruptive technologies, third-party DER providers (3Ps) should be encouraged to help build-out the new system.

New targeted DERs, whether procured from 3Ps or provided by utilities, will diminish the capital accumulated by utilities and reduce their profits. Accordingly, utilities at present have little incentive to invest in DERs, except to ingratiate regulators and other non-shareholders. This lack of incentive to use DERs is important and must be addressed.

In 2014 the Commission initiated a proceeding to integrate the separate, siloed features of the industry - notably DERs, rate-design, and the supply-side resources.⁴ It explained seven relevant problems in the industry, as follows:

1. Current Efforts are Not Forward Looking: Integrated demand-side resource policies and incentives must meet tomorrow's customer and system needs, not yesterday's.

⁴ CPUC Order Instituting Rulemaking 14-10-003.

2. *Current Efforts are too Focused on Rate-Based versus Performance Based: The existing regulatory framework rewards utilities for installing [traditional] infrastructure ... a disincentive for utilities to [acquire DERs and] no performance incentives [exist for] utilities to procure integrated [DERs].*
3. *Demand-Side Resources do not Adequately Impact System Planning, Investments & Operations: Currently [DERs] are only partially accounted for when planning generation, transmission ... distribution infrastructure [and] system operations...Demand-side resources must be integrated into system planning and operations for its full value to be properly assessed and captured.*
4. *Current Efforts Do Not Address Grid Needs: [DERs] policies and incentives do not align with the needs of transmission and distribution system operators. The integration of [DERs] should resolve problems for the grid and, ideally, reduce grid revenue requirements.*
5. *Lack of Access to Data: Third-parties are limited in their ability to identify and serve customers because they lack the data needed to understand where the electric system needs demand-side solutions, what integrated or demand side service can provide those solutions, and which customers are eligible and should be targeted.*
6. *Integration is Divorced from Rate-Making: Rate design for customers has not been coordinated with integrated [DERs] policies limiting the motivation a customer has to take action. If customers have the right economic signals, they will be better motivated to take the right integrated actions.*
7. *Market Failure of Revenue Streams: A party who invests in demand-side resources (usually the building owner) typically cannot fully capture the full value of the bill reductions that flow from that investment...This also strongly deters third-party investment in otherwise cost-effective measures, especially energy efficiency, due to the inability of the investor to fully capture the related benefit stream.⁵*

⁵ Further, some cost savings, such as avoided distribution upgrades, may be poorly captured due to the practice where avoided transmission and distribution costs are averaged across the whole system. These factors reduce the customer's motivation to contribute toward locational cost savings. Ibid.

These well-articulated Commission concerns are still very relevant and of concern to Vote Solar.

Cost-Effectiveness Issues that Mask the Economic Value of DERs

Since the early 1980's, many states use the California Standard Practice Manual (SPM) to determine cost effectiveness for DER. Vote Solar has identified at least ten specific issues with cost-effectiveness, which if resolved will substantially increase the value of DERs. A summary these ten issues follows:

1. Monthly regional peak demand forecasts are used as inputs to determine the base-case to compare DER alternatives. With more granular data, aggregate specific customer load profiles (with AMI data) and acre-level calculated demands we will be able to forecast load with much greater accuracy.
2. Average (mean) regional DER load impacts are used. With customer targeting and use of more granular data, customer-specific measure load impacts will show greater value.
3. Lack of recognition that distribution equipment can be deferred with DERs. Thus, it is important to determine the locational distribution marginal costs that can be avoided or deferred.
4. Average wholesale energy and capacity prices are traditional inputs to cost effectiveness. Use more refined (e.g., GARCH) location-specific forecasts or forward curves to project prices.
5. Capacity costs are traditionally allocated across a short duration (e.g., 250 hours/year). Now more hours are needed for reliability.
6. Avoided cost inputs are deterministic (based on single hourly average estimates). We need to transition to probabilistic analysis based on the covariance of prices, weather, and loads fully capture appropriate market value.
7. Traditional tests of cost effectiveness have relied on use of average inputs for DERs as compared to customer and location-specific inputs. This shortcoming suggests we use customer and location specific data that fit locational distribution deferral needs.

8. Marketing and implementation of separate DER programs, without integration, causes customer confusion, increased costs, and unintended consequences (e.g., higher distribution costs to accommodate ZNE buildings). We need to integrate and market DER packages (and ZNE) based on specific customers and locations.
 9. Use of average deterministic avoided costs, multiplied by average demand changes, is highly inaccurate. We can use greater data granularity and dynamic market and investment impacts to define locational and customer net-benefits.
 10. DER cost effectiveness is based on kW and kWh benefits (and costs); kVAR and voltage impacts, critical at distribution levels, are ignored. We should expand DER analysis to include distribution deferral that reflects kVAR and voltage.
- With resolve of these issues, DER value is estimated to increase by 2x to 5x.⁶

Utility Performance-Based Scope to Enable Markets and Services

The Green Book asks questions Vote Solar is keen to provide input on. With customers foremost in mind, should the *utility of the future* be encouraged to provide a more customer-focused set of products and DER services to increase economic efficiency and substantially reduce GHGs?⁷ Vote Solar answers in the affirmative.

An outcomes-based set of dashboards compels the question, what are the most important desired outcomes that are relevant, quantifiable, verifiable, and controllable? Many stakeholders have focused on dashboards that utilities seek to use. Synapse Energy Economics has offered a utility performance incentive mechanisms handbook to provide

⁶ E. Woychik, IDSMS Cost-Effectiveness: What Happened Outside of California? Results from Duke Energy, NVE, Avista ..., in CPUC R. 14-10-003, 22 January 2015; See, E. Woychik, Methods & Tools to Accomplish Distribution Resources Planning, California Public Utilities Commission DRP Workshop, 8 January 2014; E. Woychik and K. Skinner, Utility Build-out of Regional Microgrids with Advanced Analytic Methods: Local Demand Meets Maximum Value-Proposition, presentation, Advanced Workshop in Regulation and Competition: 33rd Annual Eastern Conference, Shawnee on Delaware, Pennsylvania, May 14-16, 2014.

⁷ E. Woychik and M. Crew, Developing New Business Models for Utilities with Renewables, Conservation and the Smart Grid, Advanced Workshop in Regulation and Competition: 27th Annual Western Conference, Monterey, California, June 26, 2014; E. Woychik and E. Ackerman, Utilities of the Future: Needed Changes in Business Strategy and Regulatory Policy, Advanced Workshop in Regulation and Competition: 33rd Annual Eastern Conference, Shawnee on Delaware, Pennsylvania, May 14-16, 2014.

examples of performance metrics that focus on customer needs⁸, including stakeholder engagement, effective resource planning, carbon intensity, and system load factor.

As the Green Book points out, there are other examples of performance-based-ratemaking in the U.S. and abroad.

Vote Solar suggests the focus should be on dashboards that represent desired outcomes for customers where new integrated DER markets and services – *preferred resources to reduce GHG* – should be the priority. In response to California’s customer, utility, and regulatory challenges, eight possible outcomes or dashboards indicators are suggested:

1. More economically efficient – cost causative -- price signals.
2. Faster DER resource adoption and less use of traditional (rate-based) utility assets.
3. More effective, and more complete, integration and optimization of DER resources.
4. Greater innovation through utilities and third-party providers moving at market speed.⁹
5. Greater use of community energy options and Zero-Net-Energy buildings.
6. Reduced GHG in energy and transportation; decarbonization of the electric sector should be a key factor in performance-based ratemaking.
7. Increased reliance on renewable energy.
8. Reduced customer bills.

Vote Solar Recommends that the Commission Reconfigure the Regulatory Compact to Enable Dynamic Capabilities and Change

The regulatory compact has not enabled California utilities to provide customer innovation at market speed, though 3Ps attempt to fulfill this role. If innovation is to move at market speed, dynamic capabilities must be fully part of the utility and 3P fabric

⁸ Synapse Economics, Utility Performance Incentive Mechanisms, Prepared for the Western Interstate Energy Board, 9 March 2015.

⁹ As the Green Book explains, the British RIIO approach presents a scheme for network innovation competition, network innovation allowance, and even a network innovation rollout mechanism.

to enable new services. Dynamic capabilities and resources are essential to create competitive advantage and succeed in the new energy arena.

Successful firms will design a market structure that enjoins key competencies, responds to exogenous events (e.g., business cycles, enhanced competition, and regulatory changes), embraces new technologies and collaborative firms, and responds at the speed of the market. Accordingly transformation of the electricity industry is foreshadowed by major dynamic changes in capabilities, technology breakthroughs (e.g., smart apps), declining clean energy costs, electronic management, in short smart integration and optimization of distributed sources and the grid.

With greater change in the business and technology environment, the advantages of dynamic capabilities, integration, and optimization become increasingly important to enable a firm's competitive advantage. Sustainable advantages result from inimitable capabilities, rapid adaptation, flexibility, and innovation.

Six discrete advantages that flow from dynamic innovation are further explained:¹⁰

1. Process Innovation

Specific processes are needed to define, manage, streamline, and adapt to enable product development, quality control, knowledge transfer, and technology transfer. These routines must be well orchestrated to enable dynamic efficiencies. Dynamic capabilities are essential in these areas. New software tools available now enable dynamic resource capabilities to be harnessed, at planning, dispatch, and customer engagement levels, as well as through optimization.

2. Improved Business Models

Improved business models must be a focus, an area of continuous improvement. This is how the firm delivers value to customers, compels customers to pay for value, and converts this value into profits. The revenue and cost structure must be designed to meet customer needs, consistent with the assembly of resources, the identification of market segments and channels, and the mechanisms used to capture value. The business model enables the articulation of the value proposition in terms of its scope, scale, and consumer

¹⁰ See, for more details, E. Woychik, Electric Utility Adaption to Disruptive Change: Dashboards for Success and Profitability by 2020? CRRRI 34th Annual Eastern Conference, Shawnee, Pennsylvania, 15 May 2015.

engagement. The value chain structure enables the collection of value, revenue, and profits. From this, the cost structure and profit potential must be estimated and managed. The business model architecture is based on the financial plan and its assumptions about scope, scale, costs, customers, and competitive behavior.

The business plan ultimately defines the way the firm “goes to market” and the scope and extent of the firm’s market presence. Business model adjustments are must be anticipated and well executed as conditions and the competitive landscape change.

3. Dynamic Investment Choices

Dynamic investment choices create competitive advantage when value chain elements are complementary, reinforce each other, and value is increased. As David Teece explains, this is where *cospecialized* assets are used strategically in conjunction with each other.¹¹ This is the integration function that enables greater value to be leveraged as service options and technology scope increase. Properly bundled and managed, integration of key operations enables new services that are further differentiated, provide greater benefit capture, and yield significant cost savings. In this, *cospecialized* assets can be combined to achieve to enable system integration and innovation benefits. These systems increasingly will need to be built and sized to meet specific contextual needs (e.g., at the substation or microgrid level). In different terms, integration and optimization benefits are likely to be found within specific sub-system needs and opportunities. Innovation routines can then be used to develop new cospecialization technologies, with the ultimate outcome greater focus on scope-based advantages.

4. Dynamic Adaptation Capabilities

Dynamic adaptation capabilities can be forged through informed orchestration of assets, new knowledge, and coordination with value chain partners. The firm’s assets, knowledge, and value chain partners can be orchestrated to create new dynamic capabilities that generate greater value for customers and other stakeholders in the arena. A focus on consumer needs and value chain capabilities can be approached strategically to enable the firm to use proactive adaptation and deployment.

5. Efficient Learning and Technology Development

¹¹ D. Teece, Dynamic Capabilities and Strategic Management, Oxford UP, 2009, pp. 160-63.

Dynamic capabilities derive from efficient learning and technology development across different parts of the firm. The sharing of knowledge and capabilities reflects “silo busting” and the use of otherwise untapped potential. The outsourcing of functions and joint development across the firm enables new capabilities and differentiation, and with it greater value. Hence, the development and improvement of dynamic capabilities drives value through difficult to imitate services and products.

6. Major Efficiency Gains

Substantial efficiency gains are possible with customer and locational targeting, right-sizing of resources, and orchestration of the virtual clean energy system. Distributed optimization will replace traditional utility distribution, transmission, and generation investments to produce choreographed locational benefits that are 2x to 5x greater. Greater customer value and lower bills will result with use of geospatially targeted flexible virtual power plants fueled by energy efficiency, demand response, distributed generation, storage, plug-in vehicle charging, smart inverters, and other grid innovations.

With this, three objectives are in reach. New clean energy companies can be profitable. Customers can net greater benefits. And clean energy outcomes become commonplace at scale. Customer pull and smart technology push can make this a dominant business model, largely because major benefits can be harnessed while greening the planet. The challenges then are to create consistent incentives, further engage customers, and demonstrate these major benefits, which will transform the industry.

In summary, performance dashboards can be effective to reconfigure the regulatory compact so that California meets its critical policy goals, which suggests this structure:

- Dashboards that represent desired outcomes for customers
 - More efficient prices;
 - Faster DER adoption that enables more complete integration and optimization;
 - Greater innovation, at market speed, & use of participative energy options;
 - Reduced GHG & greater reliance on renewables
 - Reduced customer bills

- Reconfigure the regulatory compact
 - Enable dynamic capabilities & change;
 - Process innovation & improved business models;
 - Dynamic investment choices and adaptation capabilities;
 - Efficient learning and technology development;
 - Major efficiency gains
- Tie shareholder incentives to greater customer & economic efficiency
 - New grid-analytics to capture pricing efficiency and net locational benefits;
 - Total marginal costs – wholesale to customer
 - Innovation to innovate and optimize -- capture locational grid efficiencies

Dashboard-based outcomes can be used to more fully calibrated and exploit key metrics. This will allow pricing, planning, procurement, operations and resource cost-effectiveness to be consistent with the proposed dashboards

A matrix of possible outcomes from this is shown in Table 1.¹²

¹² E. Woychik, Electric Utility Adaption to Disruptive Change: Dashboards for Success and Profitability by 2020? CRRRI 34th Annual Eastern Conference, Shawnee, Pennsylvania, 15 May 2015.

Table 1: Matrix of Desired Outcomes, Metrics, and Key Features

Desired Outcome	Quantitative Measure	Data Quality for Verification	Utility Controllability
1. Better price signals	Price elasticity (increase from base)	High, with large customer data base	Medium to low
2. Faster DER Adoption & reduced utility asset growth	Faster customer adoption (kWh/kW); reduced rate-base	High, with large customer data base; & rate-base forecast	High (if utility uses supportive rules)
3. Effective/complete DER integration & optimization	Higher portfolio NPV with greater penetration levels	Medium to low, as base –case (with silos) is difficult to define	Medium to high (requires CPUC policy support)
4. Greater Innovation @ market speed	Increase in 3Ps and new tech adoption	Medium, as base-case difficult to set	Medium to high (requires vendors)
5. Greater use of Community Options & ZNE	Incidence of community options and ZNE	High, simple summation-accounting	Medium to high (depends on 3P providers)
6. Substantially Reduced GHG in energy & transport	Empirical calculation of GHG	High, customer adoption data base is robust	Medium to high (energy economics may counter)
7. Greater Reliance on Renewables	Increase in RPS percentage	High, as method is defined to calculate	Medium to high
8. Reduced Customer Bills	Lower levels of bills (from baseline)	High, as data base is large, impacts clear	High to medium (as economic/vendor conditions may dominate)

Future Role of Integrated Resources Planning

Senate Bill 350 (DeLeon, 2015) requires the CPUC to periodically adopt a long-term Integrated Resource Plan to assure that the electric sector contributes to the State’s goal of reducing economy-wide greenhouse gas emissions by 40% from 1990 levels by 2030. The Commission has initiated a proceeding (R.16-02-007) with broad stakeholder participation for the development of a 2017-18 Integrated Resources Plan.

Vote Solar has participated in the IRP proceeding and believes that important progress has been achieved in making the reduction of GHG emissions the central metric in state energy resource planning. A Reference System Plan was adopted by the

Commission at its February meeting which adopted a statewide electric sector GHG reduction to 42 million metric tons by 2030, a 50% reduction in electric sector GHG emissions from 2015 levels. The Commission adopted an indicative portfolio of approximately 10,200 megawatts of new renewable resources and 2,000 megawatts of new battery storage resources by 2030. Translating that indicative portfolio into actionable procurement is the next challenge facing the load serving entities that will be responsible for reducing GHG in the electric sector.

The Draft Green Book acknowledges that Community Choice Aggregators (CCAs) have emerged as an important alternative way to manage resource procurement. These local and regional entities are relatively new at this task and have different risk profiles and creditworthiness than do traditional electric utilities. The Commission needs to make sure that CCAs meet and sustain the State's commitments to procuring new resources that reduce GHG emissions. But as many in this process have noted, DERs are not fully accounted for in the current IRP modeling process.

In its decision setting requirements for load serving entities filing integrated resources plans (R.16-02-007) the Commission has observed that in order to satisfy their portion of renewable integration, CCAs will be required to make long-term commitments for resources. Vote Solar believes that the Commission has the authority over important aspects of CCA procurement as well as planning. Vote Solar expects that in the next phase of the IRP process that the Commission will decide whether or not to certify substantial compliance of CCAs' plans with SB 350 IRP requirements.

An important component of SB 350 IRP requirements is that all load serving entities "minimize localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities."¹³ Vote Solar expects that each LSE, including CCAs, will provide a description of disadvantaged communities it serves, planned LSE programs impacting disadvantaged communities and plans to comply with the requirement to minimize air pollutants. An important refinement to the SB 350 IRP process will be the inclusion of avoided transmission and distribution costs -- total

¹³ Section 454.52 of the Public Utilities Code

locational marginal cost (LTMC) at locations¹⁴ -- which will be applied to DERs in subsequent cycles of the IRP beginning in 2019. We discuss this more in the next section.

How can California continue to support innovation for scaling up new energy technologies?

Scaling up new energy technologies requires both a long-term commitment to creating sustainable markets for these technologies as well as an orderly pathway to their introduction into the electric sector through periodic procurements and appropriate tariffs. The TLMC innovation captures comparative efficiencies previously ignored, largely through increased granularity (less averaging). The use of TLMCs is a critical new innovation. TLMCs reflect estimates of the economic efficiency of DERs at specific locations on the grid, which can be compared to estimated changes in utility revenue requirements, retail pricing, and wholesale market prices. This then enables direct comparisons of grid, market, rate-design, and 3P efficiencies, the results which can be calibrated and used as utility dashboard indicators. TLMCs provide transparent and efficient shadow prices. The TLMC is a metric to more accurately value locational distribution level costs. Accordingly, the TLMC provides a transparent reference for utility grid operations, for 3Ps, and to use in optimization of DER resource use. Importantly, TLMCs can also be used to indicate kVAR impacts, particularly to indicate payoffs for KVAR injections, voltage support, and DER at locations. Thus, TLMCs can be used to mathematically integrate the grid value and commodity-side costs, whether avoided or incurred, much like locational-marginal-costs (LMPs) are used at the wholesale level.

The benefits that DERs can provide to the grid can vary significantly based on TLMC, which should include the naturally-occurring DER resource mix. The Commission staff through the IRP Modeling Advisory Group has scoped out important

¹⁴ See, Tom Osterhus and Michael Ozog, Distribution Marginal Prices and Cost Optimization, 2015. <http://www.integralanalytics.com/>. See also, J. St. John, Distributed Marginal Price: The New Metric for the Grid Edge, GreenTechMedia, 21 August 2014. <https://www.greentechmedia.com/articles/read/distributed-marginal-price-dmp-the-new-metric-for-the-grid-edge>.

improvement is assessing location-specific distribution impacts to be included in TLMC. It is possible that avoided distribution cost will significantly affect the optimal mix of DERs and supply-side resources that are required to meet the GHG reduction targets. Future iterations of California's IRP will also need to integrate electric vehicle growth and other beneficial electrification measures into the modeling and procurement decisions.