SCE Rate Design Briefing Document – DER Compensation Discussion

The "NARUC Manual on Distributed Energy Resources Compensation" ("Manual") provides a good overview of the rate design process and issues associated with the recent influx of Distributed Energy Resources (DER).

Rate Design Principles

The Manual's summarization and thorough integration of Bonbright's rate design principles that is, rates should provide the utility a fair rate of return while allocating costs "fairly" to customers (e.g. rates based on cost of service), set a sound foundation for the overall discussion regarding DER compensation. The discussion regarding various rate structures- flat rates, inclining/declining block rates, TOU rates, fixed and variable charges is informative and timely considering recent and pending milestones for SCE. These milestones include: the recent completion of an AMI roll-out, pending redefinition of TOU periods; a completed transition of all non-residential customers to TOU rates, and pending default of residential customers to TOU rates. All of these milestones carry unique and considerable issues with respect to the equitable treatment of DER compensation.

While the majority, approximately 74%, of SCE's non-residential customers are "small" (<20 kW) and billed under a seasonal TOU energy structure with customer charges without demand charges, they represent a small proportion of SCE's overall energy sales (about 7% of total sales). The bulk of the non-residential customer usage is billed using a combination of TOU energy and demand charges, along with customer charges. Typically, variable energy costs are recovered from TOU energy charges, while Generation capacity costs are recovered via TOU demand charges and Transmission/Distribution capacity costs recovered via non-time differentiated demand charges. The breakdown of the cost recovery is approximately 8% from customer charges, 52% from energy charges, and 41% from demand charges. Typically, utilities prefer short-run definitions of cost for recovery of fixed grid and capacity elements via customer and demand charges, while short-run variable costs are recovered through energy charges. The Manual correctly focuses on the definition of costs (specifically what constitutes "fixed" versus "variable") and the resulting problem with treating all costs as "variable in the long-run" and thus recovered via energy charges. In stark contrast with the cost recovery distribution of non-residential rates, California's major IOUs collect about 1% of all residential revenue from customer charges with all remaining revenue collected through volumetric energy charges.

Section IV.A.3 of the Manual contains the crux of the policy debate. Some academician and policy-makers who subscribe to the notion that all costs are variable in the long run believe that nearly all cost recovery should be tied to volumetric rates. Utility assets are long-lived and are typically replaced after their lifetimes, making any assertion of their short-run nature quite suspect. It is also here that the Manual correctly notes that "there are additional considerations concerning historical responsibility for long-term investments made to serve the customers and usage that were projected at the time they were made." In California there are significant policies and regulations for capturing similar legacy costs through departing-load charges and fixed-facilities-related charges, with respect to departing load in the form of Direct Access and co-generation, yet surprisingly little with respect to departing load in the form of rooftop DER.

Additional Comments Regarding Rate Design and NEM Developments

Inclining block rates multiply the volumetric rate inequity by further charging higher use customers far above cost. The recovery of fixed costs via volumetric rates leads to an uneconomic by-pass opportunity offered by DERs when the energy they produce is compensated not only for the avoidance of variable costs but also for the reduction of non-avoided fixed costs. California's energy-crisis produced the most steeply inclining block rates in the country. With no relationship to cost-causation, the upper/lower tiered rate ratio exceeded 2.5:1, providing even further opportunities for uneconomic bypass by higher income-higher usage customers. A 2013 CPUC report to the CA Legislature placed the NEM subsidy at over $1 Billion/year. Partly to address this issue and the general rate inequity, AB327 was passed in 2013 to address the tiered rate restrictions and to ensure that the NEM successor tariff equates system costs and benefits.

D.15-07-001 provided a glide-path to gradually reduce the tiered rate differential to 1.25:1 by 2019. In a separate NEM decision, despite significant evidence of subsidization of NEM by non-NEM customers, the CPUC dismissed the evidence as inconclusive, and issued a decision to only partially address the issue of DER subsidies in two ways. First, some minor removal of "non-bypassable" charges from the netting calculations was made, though transmission costs remained bypassable. Second, new DER/NEM customers were required to take service on a TOU rate. SCE, like SDG&E and PG&E, are filing updated TOU costing periods that have changed, as a result of the influx of low-cost Renewable Portfolio Standard (RPS) resources. SCE's new costing periods reflect the lowest cost period in the middle of the day, with the highest cost period shifting to 4:00 PM to 9:00 PM. The RPS resource of choice, utility-scale solar, is causing prices to plunge during daylight periods of low system demand and high solar production (e.g. spring-time, weekends). These prices carry over into the DER space as the DER customers load is correlated with these same system conditions that are affecting system TOU prices overall. Solar advocates are working to minimize the effect of these market forces on the retail rates (e.g. soften retail on-peak, off-peak differentials) in order to preserve their business cases. The issue of rate grandfathering is also very contentious and counter to the principle of cost causation.

The grandfathering of NEM customers into rate schedules that reflect cost periods determined prior to the increased DER penetration and consequent NEM reform, would continue to exacerbate the issues around equitable compensation of DER. As the Manual points out, the expected payback period for DER investments is one argument made in favor of grandfathering NEM customers into their existing rates. However as pointed out in the Manual, ensuring a private party's investment return is not necessarily the responsibility of Public utility commissions. Public reaction is another argument made in favor of grandfathering. However, to fully remedy issues associated with DER in an equitable manner, DER customers must be separated into their own rate class, with a rate schedule that accurately prices the costs that they impose on the system and the subsidies that they receive. Moreover, grandfathering would prevent the introduction of time-of-use pricing of the Export Compensation Rate. TOU pricing would account for the effectiveness of exports from NEM customers in reducing system load and elucidate the benefits and costs that NEM customers impose on the system.

The cross subsidy currently associated with DER compensation and its regressive nature in requiring non-DER customers to pay energy rates reflecting the DER compensation subsidy, are a few of the most prominent controversies surrounding DER. As the Manual points out, a reduction of energy usage by DER customers and export of energy onto the system during non-peak hours prevent proper cost recovery from these customers, even though the cost to serve DER customers may be the same, if not more, than that of non-DER customers. Shifting stranded costs onto non-DER customers raises their energy rates, even though they are also least likely to possess the financial resources to invest and install DERs to produce generation and benefit from lower billing determinants themselves. As pointed out by several experts in the field,[1] solar systems tend to be marketed to and purchased by households that have higher income levels than others in the utility's customer base.

The regressive impact that DER has on the affordability of energy paid by non-DER customers is one of the arguments for separating DER customers into their own rate class, among other options. This allows any kind of subsidy created by DER customers should be felt and shouldered by DER customers only, not by their non-DER counterparts.

Demand Charges

[1] Alexander, Barbara, Brown, Ashley, Faruqui, Ahmad. "Why net energy metering of solar customers needs to go." Joint paper on net energy metering subsidies. Aug 17, 2016.

DER subsidies are less pronounced for commercial and industrial customers due to demand charges. Use of demand charges is limited in the residential space, and it is also subjected to the same claims of anti-conservation. CA's AB327 defined demand charges as a fixed charge so its broad application in the residential space is limited in CA. It is important to mention that while all of these arguments against use of a demand charge have some merit, they are not readily quantifiable. Moreover, it is uncertain whether the purported negative impacts of demand charges would be felt immediately or in the near future (e.g. 1-2 years from the date of implementation). However, utility revenue erosion and cross-subsidization between DER and non-DER customers are effects of existing DER compensation methodologies that have already been quantified and are real today. For SCE, the cost shift has been estimated to be over $4.5 billion from NEM to non-NEM customers from 2017-2019. If no changes are made to the existing NEM tariff, the cost-shift could grow to over $15 billion by 2025. These calculations were made, using the California Public Utility Commission's ("Commission") Public Tool for estimating cost shifts and the SCE Time-of-Use ("TOU") rate structures, including those that were filed in the Residential Rate OIR and the TOU-Domestic ("TOU-Domestic"). Yet, the concerns of a demand charge that is calculated from either coincident or non-coincident peak demand may not be actually realized and hence, unwarranted. It is uncertain and difficult to quantify how a demand charge sends an unclear energy-conservation signal to customers, for instance.

In an attempt to be inclusive in its coverage of controversies surrounding DER compensation, the Manual lists the costs and benefits of certain compensation methodologies such as demand charge next to one another. This approach almost gives the costs and benefits of demand charge equal weight. It does not consider the magnitude of costs and benefits or whether one could offset the other. Nor does it distinguish between the time horizon over which costs or benefits would be realized. These distinctions are crucial for regulators who must determine the appropriate compensation methodology, after being bombarded with arguments in favor and in opposition. It is crucial that the Manual distinguishes between the magnitude of impact, as well as the time horizon, of the many considerations associated with DER compensation methodology, particularly with demand charges, in future discussions, as utilities are considering use of such tools to recover costs of service from NEM customer.

Other Topics for Consideration

- **Utility Scale Solar vs. Rooftop DER solar Costs**

Utility-scale solar offers compelling economies of scale versus their DER counterparts. According to SEIA, utility-scale PPAs are now signed for $0.03 - $0.05/kWh,[2] whereas solar power procured from residential NEM customers are compensated at rates as high as $0.20/kWh. A recent Brattle study indicated central station solar was about 40% less expensive than DER.[3] DER proponents counter that DERs provide other very tangible avoided costs (e.g. abandoned transmission projects justified by DERs) that make this direct comparison invalid.

- **Should the Manual include a discussion of distribution system planning or distribution system operators?**

As discussed in SCE's 2015 "Distributed Resources Plan" ("DRP"), intermittent generation from DER can alter the loading patterns of distribution circuits, rendering current voltage control devices ineffective in voltage regulation and protection of utility and customer equipment. Flickering – variability of light output from lightbulbs due to voltage drops caused by large industrial loads or variability in DER generation – is a common problem associated with the intermittent output of power from PV systems. The DER-associated benefit of enhanced system capacity

---

[2] SEIA. Solar Industry Data. "Q1 2016 Solar Market Update: Key takeaways." http://www.seia.org/research-resources/solar-industry-data

[3] Tsuchida, Bruce, et al. "Comparative Generation Costs of Utility-Scale and Residential Scale PV in Xcel Energy Colorado's Service Area." Prepared for First Solar. July 2015. http://brattle.com/system/publications/pdfs/000/005/188/original/Comparative_Generation_Costs_of_Utility-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado's_Service_Area.pdf

and grid and service reliability could be realized, after investments in certain upgrades such as connecting smart inverters to PV and battery storage devices are made.

DER allows power to flow from substations to loads and vice versa. Existing circuit and substation equipment such as circuit conductors, transformers, fuses, and substation breakers, may not have enough capacity to handle power flowing from both directions, reducing the DER-associated potential for grid reliability. Other grid equipment that'd need to accommodate bi-directional power flow include: fault indicators that pinpoint locations of system failures and protective relays. Grid equipment would also have to integrate with additional standards and technology used to fortify the system against cybersecurity attacks and effectively protect populations in high-density urban settings from DER-related health and safety hazards.

These considerations add to the difficulty of realizing and quantifying the costs and benefits of DER, further complicating the methodology of pricing these resources. Oftentimes, the benefits cannot be realized without further investment or reinforcement of the existing transmission and distribution grid infrastructure. It is crucial that DER-associated benefits such as reduced emissions, peak-shaving, grid reliability, and others be couched in either context or language that is cognizant of the costs associated with realizing these DER-associated benefits. Only then may discussions and analyses leading up to design of a compensation methodology for DER be comprehensive. It may account for the costs inherent in the benefits, as well as the benefits inherent in the costs.

DER has the potential to meet and reduce forecasted customer load growth or anticipated load growth at the distribution substation level. However, this benefit can only be made possible by incorporating DERs into the planning process. For instance, at the distribution-substation level, the load growth rate can be above or below the system-level load growth rate. The appropriate DER technology, placed at identified high-need areas, can reduce anticipated distribution-substation load growth. However, this benefit could only be felt if DER becomes part of the discussion over distribution system planning. SCE's 2015 "Distributed Resources Plan" ("DRP") already contains assessments of the impacts of DER on distribution system planning. A discussion of distribution system planning in the Manual would add to the content of DER-associated costs and benefits discussed herein. It could be used as a transition or even add to discussions of analysis behind valuation methodologies such as "Value of Service" ("VOS"), which considers each piece connected to the distribution grid to provide value or service to the distribution network and its future development. By no means does the transition or discussion of distribution system planning or operators in the Manual need to be detailed. After all, as mentioned throughout, the valuation of DER-associated costs and benefits varies and are region-specific. Nonetheless, a discussion of DER within the context of distribution system planning offers insights on identification and valuation of additional costs and benefits, providing a well-rounded picture of DER.

Even if DER has the potential to reduce forecasted load growth, it can only do so within the limits set by distribution system requirements. Exceeding the thermal rating of substation equipment or available integration capacity at the circuit level are just some of the problems with concentrating DERs at identified high-need areas on the grid. A discussion on distribution system planning in the Manual provides additional information for planners and system operators who must integrate and support this generation resource into their outlooks and planning processes. If nothing else, the Manual could serve as a guide for distribution system planners or operators to consider when revising the current distribution system planning process to deal with increasing penetration of DER technologies in their service areas.

- New Developments since the initial survey and request for information released in March 2016 that should be taken into account in this draft Manual

The Manual characterizes VOR as the appropriate methodology for determining DER compensation in service areas with limited DER penetration. It entails identifying DER-associated costs and benefits, as well as assessing the value of each. The Manual also acknowledges that the value of identified costs and benefits will change overtime, as a result of various external factors such as location and concentration of DER technologies, natural gas prices, and the price of utility-scale renewables.

As a method of determining DER compensation, the VOR may not be appropriate, as a result of the decreasing trend of solar prices. According to the Lawrence Berkeley Laboratory, the price of solar has been decreasing at a growing pace for the following reasons. The first is a reduction in the installed project costs. According to the Solar Energy Industries Association (SEIA), the installed cost of various solar systems has decreased since the first quarter of 2015.[4] Coupled with geographical and technological improvements in solar generation, power purchase agreements ("PPAs") with solar developers have been driven down to a new low – less than 5¢/kWh. A rush to complete projects prior to reduction of the federal investment tax credit after 2016 points to continued increase in solar supply in the near future. This places continued downward pressure on the price at which PPAs are signed.

Graph 2: Installed Cost of Solar System, by Quarter and Year

Note: Detailed information about national system prices by market segment and component is available in the full report.

With the VOR methodology of DER compensation, the rate of DER customers would have to be continuously revised to keep up with changes in the purchased price of solar. If implemented, this methodology would introduce volatility to the customers' rate. If not, the rate would not accurately reflect the actual cost of serving the customer. The costs of solar power and installation are assumed to continue to decrease, in conjunction with an increase in DER penetration. These trends are likely to make VOR less applicable to determining DER compensation.

Concluding Remarks

The draft Manual on Distributed Energy Resources (DER) Compensation ("Manual") does a good job at reviewing the key issues regarding rate design, costs, and subsidies associated with DER in today's environment. SCE recognizes the nature of the Manual is not to strongly advocate for or against any specific rate design or methodology, but rather to illuminate key issues and consideration regarding DER compensation. SCE concurs with the overall direction of the draft Manual, which is to promote least-cost alternatives for reducing cross-subsidies, with a focus on cost causation rate design as a cornerstone of future policy.

[4] SEIA. "2.2. National Solar PV System Pricing." Solar Market Insight Report 2016 Q2. http://www.seia.org/research-resources/solar-market-insight-report-2016-q2