BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters	Application 15-07-002 Application 15-07-003 Application 15-07-006

POST-WORKSHOP COMMENTS OF THE CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION

Brad Heavner
Policy Director
California Solar Energy Industries Association
1107 9th St. #820
Sacramento, California 95814
Telephone: (415) 328-2683
Email: brad@calseia.org

March 3, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters	Application 15-07-002 Application 15-07-003 Application 15-07-006

POST-WORKSHOP COMMENTS OF THE
CALIFORNIA SOLAR ENERGY INDUSTRIES ASSOCIATION

The California Solar Energy Industries Association (CALSEIA) respectfully submits the following comments in response to *Administrative Law Judge's Ruling Inviting Comments on Integration Capacity Analysis Methodologies, Integration Capacity Analysis Workshop Report, Locational Net Benefits Analysis Methodology, Locational Net Benefit Analysis Workshop and Demonstration Projects A and B* (Ruling), issued on February 18, 2016.

1. Introduction

Increased penetration of solar in the state electricity system will require a more advanced approach to grid management. The Legislature recognized this in passing AB 327, which directs the California Public Utilities Commission (Commission) to create a new tariff for customer-generators and to require utilities to change their processes for planning grid expansion and maintenance. This evolution of relationships and processes will be challenging. Solar companies will need to give increased consideration to grid impacts when helping customers install solar energy systems, and may need to develop more sophisticated tools to explain the impacts of increasingly complicated tariffs. Utilities will need to manage a more complex system of interacting pieces, and to minimize costs to ratepayers while mastering new capabilities. In tackling these challenges to pursuing a more advanced grid, CALSEIA looks forward to working productively with all parties on this effort.

In the face of this challenge, utilities can avoid business as usual expenses and can make improvements to the interconnection process that will enable solar providers to design systems appropriately and thus minimize the review process that is currently incredibly inefficient. This will be an ongoing effort, but to meet our state's climate goals, we must get it right.

Also, as more distributed energy resources (DERs) are incorporated into the grid, the role of ancillary services that DERs provide will become increasingly important, and the values they provide to the grid must be identified and encouraged. How the locational value of distributed energy resources such as solar electric systems, advanced inverters, grid-connected storage and other related equipment is assessed and incorporated into future tariff structures will impact the deployment of DERs. Much work is needed to make sure this process achieves its intended goals and we have a framework for valuing DERs that properly takes into account the full value they provide to our grid. This contrasts with the utilities' collective presentation at the Locational Net Benefits Analysis (LNBA) workshop where they presented a very narrow procurement process for valuing and integrating DERs into the electrical grid.

2. Integration Capacity Analysis

At the ICA workshop, several parties indicated that incorporating the ICA into Rule 21 would improve the interconnection process. It is important that there is a venue for discussion of this issue to realize the full potential of the ICA and to make sure that ICA development is as effective as possible for application in Rule 21. One of the advantages of the ICA is to provide additional information on the level of distributed resources that the distribution grid can handle. Rule 21 has historically used rule of thumb approximations for engineering screens, such as the requirement that peak capacity of distributed generation on a circuit cannot exceed 15% of the circuit's peak load without triggering detailed engineering studies. However, the actual capacity of a circuit is dependent on the specifics of that circuit, as is being quantified in the ICA. In many cases the integration capacity is greater than conservative rules of thumb. It is time to take a more accurate view of that question, and data from the ICA can form the basis for a new screen. Furthermore, it is critical that the ICA take into account the operating capabilities of DERs as mandated in the Commission's Interim Decision[1] on smart inverters and recommended communications pathways and advanced inverter capabilities in the Commission's Smart Inverter Working Group (SIWG). Without consideration of these capabilities, the potential for DERs to increase hosting capacity, as well as streamline interconnection, will not be properly accounted for in the ICA, nor in the LNBA when determining the benefits and values of DERs. While the Commission has not yet decided to include Rule 21 in the scope of the ICA and LNBA discussion, it must

[1] See D.14-12-035, "Interim Decision Adopting Revisions to Electric Tariff Rule 21 for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Require Smart Inverters," issued December 14, 2014 in R.11-09-011.

be recognized that there is a direct linkage with the work being conducted in the DRP proceeding. Therefore, it is critically important to consider the operational capabilities mandated by the Commission in Rule 21, and the recommendations made by the SIWG to adequately account for DER functionality in the distribution modeling exercises undertaken to determine ICA and LNBA methodologies.

In addition, CALSEIA strongly agrees with one of the stated objectives of the ICA process, to inform and improve the efficiency of Rule 21 grid interconnection process while maintaining the applicable safety and reliability standards.[2] In addition, the maps for each investor-owned utility's distribution system have great potential to facilitate the deployment of solar resources.

The ICA maps have potential to improve the interconnection process, but as they exist today they lack in actionable, practical information for project development for several reasons. While PG&E mapped more than 3,000 feeders, the scope was limited to the 3-phase circuit level. According to the analysis presented at the ICA workshop by the Office of Ratepayer Advocates, that misses a large portion of feeders (up to 63% based on the number of customers).[3] The other utilities' information is far less granular. SCE's was based on modeling only 30 circuits that they deemed to be representative, which is not accurate for planning and development purposes. For all of the IOUs, the maps only include currently integrated systems and do not include the queue of pending projects in that location.

---

2 "Joint IOU Workshop Report on the November 10, 2015 Workshop Regarding Integration Capacity Analysis Methodologies and Integration Capacity Analysis Demonstration Project A," filed February 18, 2016, Attachment A at p. 4.

3 Tom Roberts, Office of Ratepayer Advocates, "Evaluation of Utility Integration Capacity Analysis (ICAs)," presentation at the ICA Workshop, November 10, 2015.

The Commission should direct the IOUs to make the ICA dynamic, not static as it is today, with a continuously up-to-date view of system conditions and forecasts based on various grid conditions over time. The Commission's Long-Term Procurement Planning (LTPP) process, the Commission's Renewables Portfolio Standard (RPS) Calculator, and the California Independent System Operator's (CAISO) system flexibility modeling all employ dynamic system and scenario analysis to inform procurement decisions. The determination of need for DERs at the distribution level should be supported by similar dynamic tools if the Commission's objective is to determine the long-term value of DER resources, not short-term value based on discrete near-term procurement opportunities as the ICA is set up for today. This point was clearly communicated at the Commission's November 16, 2015 workshop by many in the academic community that presented.[4] The need for dynamic modeling is particularly important as the state moves toward procurement based on Integrated Resource Planning (IRP). Anything less would forestall the development of a modernized distribution grid that is reliable and cost effective. Furthermore, the ICA maps should provide the number of megawatts of projects in the queue associated with that section of the map, including where the project stands in the evaluation process. Without that information, the data presented is not an accurate representation of the actual capacity on a circuit.

CALSEIA members have expressed frustration with the process surrounding the existing Renewable Auction Mechanism (RAM) maps and the static nature. Projects submitted for application on what appeared to be viable places on the grid resulted in situations where the interconnection costs were much higher due to additional projects

---

4 See http://www.cpuc.ca.gov/General.aspx?id=5071, "Academic Perspective on Utilities' Distribution Resources Plans Public Workshop," November 16, 2015.

interconnected into the system that were not listed in the RAM maps. This results in lost time and increased costs for doing business, especially if it results in a project no longer being economically viable. Transparency conveyed through the maps and entire ICA and interconnection process is critical to the success of this effort. In addition, data reflecting the current amount of other machinery on the line would be highly beneficial. For example, if utilities use the existence of synchronous generation on a line segment in their anti-islanding screen, as PG&E has begun doing, this information would also be necessary in a dynamic ICA map.

3. Locational Net Benefits Analysis

An important outcome of the LNBA process is an agreed upon list of categories for locational values of DERs, a uniform methodology across IOUs for determining each value, and ultimately agreeing upon the values associated with DER on the grid. The utilities demonstrated at the LNBA workshop that they intend to take a much narrower view on the valuation of DERs. The Commission should direct them to return to the original intent of the LNBA process and provide clear, consistent methodologies and a comprehensive list of categories and values for the local and operational/system attributes of distributed resources. This includes consideration of all the operating capabilities of DERs as mandated by the Commission and recommended by the SIWG in the Rule 21 proceeding.

The utilities' presentation reduced the LNBA process down to only assigning value to DERs when DERs can address a known location on the grid where upgrades are otherwise planned. Even though utilities included several categories as having potential locational value, the utilities focused on the importance of differential deferral value as the component with likely the largest value. Ultimately, the utilities' recent proposal essentially dropped the development of methodologies to calculate value of DER throughout the grid. This is in contrast with all three IOUs filings on July 1, 2015, which outlined a step-wise process to quantify the locational net benefits of DERs.[5] However, the narrow scope recently taken by the utilities loses the calculation of the net value of DERs in locations that have not been identified as being in need of an upgrade with the traditional planning horizon. The Guidance document for the Distribution Resources Planning (DRP) proceeding stated that the LNBA "analysis will specify the net benefit that DERs can provide in a given location," and listed many items the utilities need to include in their analysis, including a "unified locational net benefits methodology consistent across all three Utilities."[6]

Utilities plan for distribution system upgrades within a ten-year planning horizon, and DERs can remain operational for thirty years and even longer. This difference is fundamental. There is no way to capture the value of a thirty-year asset if the window of analysis is limited to ten years. For this reason, the utilities must develop a DER valuation methodology independent of items that are currently in their ten-year list of planned system upgrades. This can be remedied by taking a dynamic approach to modeling ICA that is scenario-based rather than the static approach currently being taken. Quantification of the long-term value of DERs, both locally and operationally (i.e. ability to mitigate truck roll-outs, forecast grid events, streamline interconnection), must be an

5 "Pacific Gas and Electric Company Electric Distribution Resources Plan," starting at p. 62; "Southern California Edison Distribution Resources Plan," starting at p. 52; "SDG&E Distribution Resources Plan," starting at p. 38; filed July 1, 2015.

6 "Guidance for Section 769 – Distribution Resource Planning," Attachment to Assigned Commissioner's Ruling On Guidance For Public Utilities Code Section 769 – Distribution Resource Planning, filed February 6, 2015, Attachment at p.4.

essential component of the distribution planning and procurement process. Taking a short-term view will result in a targeted procurement process that contemplates only a fraction of the value a DER can provide to the grid and consumers.

Per question #5, this is one area where the LNBA process can be informed by the ICA and vice versa. It is important that the LNBA process determines the value of DERs on a “green” circuit and the value that DERs have in keeping a circuit “green” and avoiding additional congestion, avoiding upgrades, and extending the life of existing distribution system equipment.

Leveraging the attributes DER can provide to the grid results in significant net benefits to society, as can be seen if all values are considered together. For example, the valuation approach and analysis of DERs presented by SolarCity in a recently released white paper calculated the net benefits of DERs at $1.4 billion per year in California by 2020.[7] In addition to the original DERAC cost-benefit categories, the paper included five additional categories of values that DERs provide, including voltage and power quality, conservation voltage reduction, equipment life extension, reliability & resiliency, and market price suppression, and laid out a methodology for valuing those hard-to-quantify categories. The paper also considered the costs associated with incorporating DERs into the grid. The SolarCity paper warns that the benefits cannot be fully captured under the existing regulatory structure and encouraged two things that can be addressed in the DRP: the development of mechanisms to reduce the financial disincentive utilities face against deploying DERs and the development of a distribution planning approach to fully consider the potential of DERs. These are important recommendations that the Commission must incorporate.

---

[7] SolarCity Grid Engineering, “A Pathway to the Distributed Grid,” February 2016.

The utilities should provide greater detail in their methodology and the data employed for determining the constraints on the grid and the determined values of DERs in their analysis. This information is particularly important in the limited process recommended by utilities – identify the need for upgrades, determine which can been deferred with DERs through a feasibility screening process, release competitive bids, and evaluate. This procurement process encourages traditional resources over DERs. In particular, the inclusion of a feasibility screening process for whether or not DERs could provide value or compete with traditional resources prior to releasing solicitations for competitive bids could severely constrain the usefulness of the LNBA process to encourage DER deployment by missing the opportunity for DER providers to offer alternative solutions. In addition, only larger projects or aggregated resources would likely be eligible to compete. Highlighting the original intent of the LNBA process, it misses assigning value to new smaller-scale DERs into the distribution grid. If resources cannot beat conventional energy sources in a traditional process, they have no value. This is not the forward thinking process envisioned in the DRP guidance, which articulated three parallel goals:

1) To modernize the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs' networks;
2) To enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner; and
3) To animate opportunities for DERs to realize benefits through the provision of grid services.[8]

Market animation requires a new approach to determining what gets built for the distribution system of tomorrow. Periodic issuance of Requests For Offers (RFOs) for the

[8] "Assigned Commissioner's Ruling RE Draft Guidance for Use in Utility AB 327 (2013) Section 769 Distribution Resource Plans," filed November 17, 2014 at Attachment pp. 4-5.

provision of services to meet discrete needs will not enable wide scale investment and innovation among companies seeking to pursue opportunities. Rather, a dynamic marketplace is needed in which entrepreneurial companies are able to develop energy solutions without waiting for utilities to issue RFOs. For this, there must be a methodology for calculating value for all potential resources. And this must be done with a long-term perspective that matches the expected lifetime of those resources.

While the Integration of Distributed Energy Resources (IDER) proceeding will be the venue to discuss tariff structure and compensation mechanisms, the inputs from the LNBA process will inform the IDER conversation. It will be important to send market signals and encourage all parties to pursue the most cost effective outcome of the policy-driven deployment and growth of DERs.

There also must be independent review of utility decisions of whether to rely on DERs in place of traditional investments. Under the current regulatory structure, utilities have an inherent bias against DERs, and that must be overcome. Because utility profits are tied to infrastructure spending, they are motivated to address needs with equipment that they build and add to the rate base. Ultimately the Commission may need to create an independent distribution system operator or create performance-based compensation for utilities. In the near term, the Commission must create a transparent oversight process for utility planning.

4. Conclusion

CALSEIA envisions the ICA and LNBA processes as the chance for a collaborative and iterative effort between the engineering teams of the utilities, DER developers, and all parties to solve problems and drive to solutions. A fair evaluation of locational values of DERs can encourage all parties to pursue the least cost, best performance alternative in a transparent process. We look forward to continuing to work with all parties in pursuing a smooth transition to this vision.

Respectfully submitted this March 3, 2016 at Sacramento, California,

By: /s/ *Brad Heavner*
Brad Heavner

Brad Heavner
Policy Director
California Solar Energy Industries Association
1107 9th St. #820
Sacramento, California 95814
Telephone: (415) 328-2683
Email: brad@calseia.org