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 Applications.	Application 15-07-002 Application 15-07-003 Application 15-07-005 Application 15-07-006 Application 15-07-007 Application 15-07-008

RESPONSE OF NRG ENERGY, INC. TO THE DISTRIBUTION RESOURCE PLANS

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In accordance with Administrative Law Judge David M. Gamson's July 27, 2015 *Administrative Law Judge Ruling (1) Consolidating Proceedings (2) Setting Prehearing Conference and (3) Granting Motion for Extension of Time*, NRG Energy, Inc. ("NRG") hereby submits these initial comments on the Distribution Resource Plans ("DRPs") submitted on July 1, 2015 by the Pacific Gas and Electric Company ("PG&E"), the Southern California Edison Company ("SCE") and the San Diego Gas & Electric Company ("SDG&E").

I. EXECUTIVE SUMMARY

NRG appreciates the effort put forth by California's Investor Owned Utilities ("IOUs") to rethink the way utilities in California plan for the future needs of the distribution system. In particular, California's utilities have taken an important first step towards making their systems more transparent by beginning the process of making maps that will guide future deployments of Distributed Energy Resources ("DERs"). However, more is needed in order to fully implement

President Picker's Guidance Ruling.[1] NRG provides two general sets of comments, first on the specific DRPs, and second, to further explore the ability of the competitive deployment of customer-facing DERs to increase the benefits of distributed energy systems while reducing costs for all ratepayers, relative to other approaches.

In regards to the DRPs, NRG recommends that the Commission analyze the DRPs with the following in mind:

1. A thriving marketplace for customer-hosted DER products already exists. The goal of Section 769, as interpreted in President Picker's guidance, is to align the IOU distribution planning processes with the anticipated growth of the DER sector. As such, the DRPs should be designed to encourage investment in, and deployment of, DERs.

2. The hosting capacity "Heat Maps" proposed by the utilities are a good beginning, but require refinement. To better facilitate customer choice, the Maps must identify locations where DERs would *add* value to the system, in terms of deferred distribution upgrades, decreased delivery costs, or other distribution system benefits.

3. The data underlying the hosting capacity maps should be made publically accessible (subject to appropriate confidentiality provisions) and include information comparable to that provided after completion of a "Pre-Application Report" under California's Rule 21 interconnection process.

4. The hosting capacity maps should incorporate electrical constraints, other than pure line capacity, at a given location on the distribution system, which are often key to efficiently siting DERs

5. The DRPs need to recognize that many DER hosts and/or DER aggregators are capable of providing multiple energy products at the same time, to the customer, to the distribution system, and to the bulk power grid.

Additionally, NRG also provides comments on the need for DRP plans to focus on the utilities' distribution *planning* processes and not pre-judge how California eventually implements distribution *pricing* or how DERs are dispatched and controlled. As President Picker's Guidance

[1] *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning,* issued February 6, 2015 in Rulemaking R.14-08-013 ("Guidance Ruling").

notes, whether utilities will be in the business of directly owning or controlling DERs is outside the scope of this proceeding. NRG agrees with President Picker's Guidance that such issues merit further exploration, and that it will be constructive to begin that exploration in this proceeding. For that purpose, NRG respectfully offers the following principles for allocating responsibility for DER ownership and control to create a robust DER system that will reduce costs for all ratepayers:

1. Unlocking consumer value requires that the DER hosts and/or third-party suppliers or aggregators of DER products, maintain the primary operational control over their resources.

2. Consumers are less likely to invest in integrating DERs into their homes and businesses if DERs are viewed as just another set of utility assets, rather than as customer assets that benefit the distribution system and the wholesale grid.

3. To these ends, NRG believes the most cost-effective and beneficial DER regime will include a clear distinction between the IOUs' role in directly operating the distribution *system* and the more decentralized operation of DERs themselves. It will be neither feasible nor effective, in our view, for utilities to directly operate or control thousands or millions of energy management and production devices in customers' homes and businesses.

4. Utilities should focus on developing the demand side of the DER marketplace, with the ability to send price signals to aggregated customer-based DERs and so elicit the supply of DER services that will allow the utilities to better maintain reliability and enhance distribution system performance.

However, to the extent that the Commission decides to address any of these issues in this docket, NRG respectfully urges the Commission to base those decisions on the principles above.

I. BACKGROUND

President Picker's February 6, 2015 Guidance Ruling laid out three broad goals:[2]

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.

Simultaneously, the Guidance Ruling clarified the appropriate scope of the DRP process:[3]

> Some Parties would like this proceeding, and the DRPs, to serve as platforms for reinventing the existing utility distribution services model – perhaps along the lines being investigated in New York State's "Reforming the Energy Vision" (REV) process. That is not the focus of this proceeding. As the Order Instituting Rulemaking in this proceeding stated, "The goal of these plans is to begin the process of moving the IOUs towards a more full integration of DERs into their distribution system planning, operations and investment."
>
> Given the significant change this will represent to traditional distribution planning processes – which are mainly focused on meeting expected load growth and potential peak consumption without much regard to customer-side interactions – even this relatively narrow focus may be considered ground-breaking.
>
> While it is logical to conclude that effective integration of DERs at the level envisioned by this Rulemaking may well trigger necessary changes to business models and utility service platforms, that is a longer term prospect, and beyond the scope of this current proceeding and the attached Guidance document (appended to this Ruling). Nonetheless, there may be opportunities in the context of this proceeding to begin exploring ideas for the future – this can only benefit the Commission, IOUs and Parties in understanding the long-term implications of the actions that we begin today.

Thus, President Picker's Guidance Ruling put strong boundaries around what IOU plans should, as well as what they should not, try to accomplish in this first round of DRPs.

[2] Guidance Ruling, at p. 3.

[3] *Id.* at p. 5.

II. ISSUE SPECIFIC COMMENTS: COMMENTS ON DRPS

President Picker's Guidance Document contemplated the evolving nature of the DRP process when he wrote that "although § 769 appears to call for a one-time exercise in this new method of Distribution Planning, there appears to be general agreement that this should really be an on-going, cyclical process that will repeat over time to incorporate how technologies and market policies are evolving and to take advantage of lessons learned in previous cycles."[4] With that in mind, NRG highlights several specific items that will improve the DRP process as it moves forward in achieving the Commission's objectives of (i) modernizing the electric distribution system, (ii) enabling customer choice of new technologies and services, and (iii) allowing DERs to provide distribution grid services.

A. DRPs should Expressly Contemplate that DERs Will Provide Multiple Grid Services at the Same Time.

In ruling on the DRPs, NRG recommends that the Commission approach the proposed planning process changes from the view of a customer considering a DER investment. A typical customer will find investment in DER capability compelling if the sum of three value "buckets" exceeds the cost of the DER investment:

(i) the value the customer itself derives from its DER;

(ii) the value to the distribution system, as expressed in payments to the DER host from the distribution system operator; and

(iii) the value that the DER is able to earn by providing services to the wholesale market.

In order to achieve this "triple value proposition," DERs must have the ability and right to access both distribution and wholesale markets, as well as to utilize the attributes of their distributed

[4] Guidance Ruling, at p. 4.

resources for their own benefit. In fact, as the DER market matures, it is likely that many DERs will earn revenues through a series of simultaneous transactions that allow them to aggregate multiple sources of revenues corresponding to the multiple values the DER can provide to the host customer, as well as to the operators of the distribution and transmission systems.

The current iterations of the DRPs, however, do not adequately contemplate how contributions from DER owners would be measured or compensated. As President Picker emphasizes, "[a]n inevitable consequence of these rapidly evolving changes to utility distribution will be the need to add new infrastructure, enhance existing networks and adopt new analytical tools to allow consumers to be active managers of their electricity consumption through the adoption of DERs; the goal being to create a distribution grid that is 'plug-and-play' for DERs."[5] NRG suggests that future iterations of the DRPs more clearly identify how the contribution of DERs to both the distribution system and the wholesale grid will be measured, as well as what improvements to the distribution system are necessary to accommodate the "plug and play" deployment of DERs.

NRG already sees DERs providing value, both within and outside of California. For example, electric vehicles can potentially earn incremental revenues by participating in multiple ancillary services markets, both at the distribution and wholesale levels. NRG is currently providing ancillary services from electric vehicles to the PJM market on a trial basis, with positive initial results. Additionally, any DER with a digital inverter – not just traditional back-up generators – is capable of adjusting power factor and supplying VARs to the system. The provision of reactive power from such resources directly to the distribution system may be the most cost-effective way of stabilizing voltage on feeder lines. Distributed suppliers of reactive

[5] Guidance Ruling, at p. 3.

power also lower the utility's costs of delivering power, because they allow the utility to deliver a higher proportion of real power.

Notably, the CAISO is already beginning to take the necessary steps to allow aggregated DERs to fully participate as suppliers in its wholesale markets. In the *Olivine Report* recommendations,[6] CAISO suggests creating additional market products and reducing metering and telemetry costs that today make participation in the wholesale markets financially untenable. Likewise, the CAISO is currently evaluating whether to compensate grid resources, whether at the distribution or transmission level, for the provision of reactive power within a minimum power factor range and to maintain voltage within a range specified by the utility.[7] Additionally, the CAISO Board recently approved the CAISO's Distributed Energy Resource Provider ("DERP") proposal, which facilitates the participation of DERs in the CAISO's wholesale markets.[8] Beyond the DERP, the CAISO recently launched its Energy Storage and Distributed Energy Resource ("ESDER") stakeholder initiative. This initiative will explore important issues, including how DERs can provide distribution reliability services or behind-the-meter customer services and simultaneously participate in CAISO wholesale markets.[9] As the DRPs move

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[6] *See* Olivine Report on Distributed Energy Resource Challenges and Barriers, *issued* March 18, 2015, *available at* http://www.caiso.com/informed/Pages/CleanGrid/default.aspx.

[7] NRG notes that each of the organized markets outside of California (with the possible exception of SPP, which has a hybrid compensation scheme) compensates resources for providing reactive power services.

[8] The CAISO's Distributed Energy Resource Provider proposal is described in the CAISO's June 10, 2015 *Expanded Metering and Telemetry Options Phase 2 Distributed Energy Resource Provider (DERP) Draft Final Proposal*, *available at* http://www.caiso.com/Documents/DraftFinalProposal_ExpandedMetering_TelemetryOptionsPhase2_DistributedEnergyResourceProvider.pdf.

[9] Information on this CAISO stakeholder process can be found at http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_AggregatedDistributedEnergyResources.aspx.

forward, NRG respectfully requests that the Commission ensure that they remain consistent with providing consumers the opportunity to achieve the three value streams discussed above.

B. The Integrated Hosting Capacity Analyses Should Identify Locational Value and Improve the Identified Distribution System Constraints.

While NRG appreciates the substantial work put into the integrated hosting capacity "heat maps" to date, the currently iteration of the maps largely focuses on where distributed resources can and cannot be installed without triggering the need for network upgrades, and only partially accomplishes the Commission's larger goal of guiding deployment of DERs in a manner that reduces overall distribution system costs. As experience has already shown, DERs can help utilities avoid the need to upgrade the distribution system altogether, or at least reduce the scope and cost of necessary upgrades. Keeping President Picker's guidance in mind that these maps represent only the first in a longer series of reforms, NRG makes the following recommendations for future work on the distribution maps:

First, NRG is concerned that the heat maps do not contain the sufficient information to adequately identify where private DER investment on the distribution system would create locational value, *e.g.*, by helping avoid or defer distribution system investments. The reduction in distribution system expansion costs is a key part of the Commission's vision for the DRP process:[10]

> A significant component of the net benefit calculation will be whether deeper penetration of DER in a particular location or on a specific feeder will be able to provide an alternative to the most costly upgrades of distribution (or eventually transmission) facilities that might otherwise be necessary to meet load. The deferral or avoidance of network upgrades may, in fact, offset much of the expected costs of accommodating new customer-side resources.

[10] Guidance Ruling, at p. 4.

However, the maps in their current form focus on identifying areas where DER installations would not *increase* utility costs, which is very different from identifying geographic locations where DER installations would create value by *avoiding* future utility costs. NRG urges the Commission to require that future maps clearly indicate the geographic regions on the system where DER deployment would have the greatest impact in mitigating the need for more costly utility investment in distribution system improvement, as well as the specific DER capabilities that would best support such distribution system cost reductions. In addition, the Commission should clarify that the hosting capacity maps are intended to serve as both as guides to where the DERs create the most overall value, and as indicators of where distribution system hosting capacity needs to be upgraded. Otherwise, their use may inadvertently convert planning for robust DER deployment into the simple identification of impediments to that deployment.

Second, future versions of the hosting capacity maps should include additional types of information necessary to efficiently deploy DERs. In many cases, DER deployment is limited by factors other than pure circuit capacity. In other cases, the value of a DER system to the grid (for example, in providing VARs that decrease real power delivery costs) is a function of electrical characteristics that currently are not included in the data provided by the utilities. Comparable utility maps filed in New York, for example, identify places where DERs could mitigate the need for increased delivery capacity investment and thus, where DER deployment would most effectively reduce ratepayer costs. Indeed, Consolidated Edison has reduced the costs associated with a highly congested portion of the Brooklyn distribution system by hundreds of millions of dollars by encouraging the deployment of DERs.[11] While decisions over pricing on the

[11] *See, e.g.*, New York Public Service Commission, Case 14-E-0302, "Order Establishing Brooklyn/Queens Demand Management Program," issued December 12, 2014 ("This is the first time that the Commission is requiring a utility

distribution system are clearly premature at this point, NRG anticipates that the Commission may eventually elect to compensate DER owners for such things as increased transfer capability, decreased loading, or other attributes that increase total hosting capacity or decrease the need for utility investments in the distribution grid. Detailed knowledge of what electrical services are needed where is obviously critical information for DER developers, so that they can deploy resources in the manner most likely to drive consumer *and* distribution system value.

Third, the usefulness of the maps in deploying cost effective and well-sited DERs would increase immeasurably if the utilities made information available on their heat maps comparable to the information available under a Pre-Application Report, under the Rule 21 interconnection process. A Pre-Application Report includes a detailed breakdown of the various elements of individual circuits, allowing developers significant insights into, not only whether the application is likely to trigger a more detailed study process, but also the likely results of that study.

Fourth, the maps are only as useful as the underlying assumptions that went into making them. For example, many of the utilities appear to have based their “green-yellow-red” coloring based on the conservative assumption, reflected in the Rule 21 Fast Track screening criteria, that minimum load on a particular circuit is equal to 30% of the peak load on the circuit, and that only half of that 30% is available to support DER deployment (in other words, 15% of the peak circuit load), without the installation of additional protective relays and breakers. Such protective schemes often make smaller DER investments infeasible, and appear to reflect overly conservative assumptions about the ability of the existing distribution system to safely and reliably interconnect DERs. In the future, NRG recommends that the Commission require more

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to actively and vigorously work to address growth in system demand in a manner other than through traditional utility investment.”)

granular inputs into the model and allow the Commission (and developers of DERs) an enhanced ability to utilize their own screening criteria in selecting potential DER deployment locations.

Finally, NRG strongly recommends that the Commission direct the utilities to make available, subject to appropriate confidentiality restrictions, the information underlying the maps. Again, providing the information in an electronic format that could be manipulated using standard programming tools would give developers critical insights into how to best deploy DERs.

E. The DRPs do not Sufficiently Address the Value of Third-Party Demand Response Resources.

There is no question that reducing peak power requirements provides enormous economic benefits at the wholesale level by reducing the need for expensive (and relatively higher emitting) peaking generation facilities. However, DER providers, and in particular, demand response resources, can also be used to obviate, or delay, the need for expensive distribution or transmission expansions. These benefits are separate and distinct from the lower wholesale market prices and bulk power system reliability benefits that the wholesale market attributes to demand response. Accordingly, demand response providers, like other providers of DER services, provide multiple services at the same time, and should be encouraged to offer these distinct services and benefits both to the wholesale market and to the distribution utilities.

In evaluating the DRP proposals in regards to demand response programs, the Commission should consider New York's initiative currently underway, which requires all utilities to roll out distribution-level demand response programs featuring peak shaving and local distribution system reliability programs. Indeed, the state of New York permits dual participation in both distribution level and wholesale level programs, and companies such as NRG's demand response affiliate, ECS, have been able to leverage these two streams of revenue into significantly higher levels of participation by demand response customers. A similar distribution level demand response programs in California would increase total market demand response penetration while assisting electric distribution companies in controlling peak load.

F. The DRP Programs Should Include More Sharing of Real-Time Energy Information.

Access to energy usage data is critical to efficiently deploying and operating DERs. For example, demand response providers rely on the analysis of meter data to optimize load visibility and maximize load curtailment during forecasted peak hours or emergency events. Further, real-time meter data is necessary to identify historic trends and create reliable customer load profiles, monitor real time energy use and demand, and also for aggregators of DERs to have the ability to react to abnormalities *prior* to the deployment of contingency events. DER providers thus need access to real-time data in order to anticipate end user performance, as well as to ensure that customers are providing the necessary response the utility is counting on receiving. Providing third-party aggregators, with the customer's permission, open access to meter data on a real-time or similar basis, is thus critical to the expansion of DERs in California.

E. The Proposed Distribution Planning Review Group Should be Implemented on a Modified Basis.

In its DRP, SCE proposed creating a "Distribution Planning Review Group" ("DPRG"). According to SCE, this group would: (1) review how SCE applies the Commission-approved distribution investment deferral framework,[12] and (2) promote transparency related to certain aspects of SCE's distribution planning activities related to DER deployment.[13] Per SCE, this

[12] SCE DRP, at pp. 70 *et seq*.

[13] SCE DRP, at pp. 12, 16.

group would be modeled after the Procurement Review Group, and would be made up of eligible non-market participant parties who would sign non-disclosure agreements with each utility.[14]

SCE's idea to form a group to bring greater transparency to the distribution planning process has merit. Transparent, repeatable, understandable distribution planning processes will be critically important in the move towards a more distributed grid. However, we note that modeling the DRPG after the Procurement Review Group would exclude market participants (*i.e.*, DER providers), which would greatly reduce, if not negate, the usefulness of the proposed DPRG in improving the transparency of the distribution planning process. A DRP planning process that excludes DER providers is unlikely to motivate optimal levels of DER deployment and performance.

III. COMMENTS ON LONGER-TERM POLICY ISSUES

President Picker's Guidance Ruling listed fourteen separate proceedings that "…directly relate to areas that are potentially encompassed by the DRPs."[15] The Guidance Ruling went on to direct that the DRPs are not intended to supersede policy or program decisions that fall to the separate proceedings, nor are the DRPs to be the forum for adopting new tariffs that are instrumental to certain technologies, a task that belongs in the specific proceeding.[16] NRG understands that the Commission's goal in the DRP process is to establish a distribution planning regime that ensures utility planning criteria incorporate assumptions that allow for increased penetration by DERs. As such, the Commission should find that portions of the IOU DRPs

[14] SCE DRP, at pp. 70-71.

[15] Guidance Ruling, at p. 10.

[16] Guidance Ruling, at pp. 10-11.

addressing utility ownership or control of DERs, while appropriate for further exploration in this docket, are not ripe for decision.

A. The Issues of Utility Ownership and Direct Control Over DERs Warrants Consideration in Future Proceedings.

Two of the most important long-term issues confronting the Commission are (i) whether the IOUs should own customer-sited DERs and (ii) whether the IOUs should play a "command and control" role in dispatching or otherwise contorlling customer-sited DERs. Indeed, all three IOU DRP proposals suggest that the utility could serve as a DER owner or DER operator. NRG respectfully suggests that there are a number of dockets where decisions on these issues are better addressed. However, to the extent that the Commission decides to address these issues in this docket, NRG suggests that issues around utility ownership and direct utility operation of DERs cannot be determined without a careful review of the impacts on customer choice and competitive options.

As a matter of public interest, the Commission should seek to maximize private innovation and minimize ratepayer costs and risk in its DER policies. One hundred years of experience has shown that innovation is largely driven by competitive companies investing shareholder dollars and putting their own capital at risk as they compete to satisfy customer needs. Today, many of the largest and best-capitalized consumer-facing companies in the world are bringing products into the DER space. Given the growing ability of consumers to spend their own money (rather than other ratepayers' money) to buy and deploy DERs, there is significantly less need to rely on monopoly implementation of these new technologies.[17] Allowing private

[17] Today's mobile telephone industry is a prime example of consumers being willing to spend money to "upgrade" services that they have received from a monopoly provider for decades. Indeed, affiliation with a legacy carrier is often a detriment to public acceptance of new products and offerings.

sector, consumer-driven investment to flow into the DER sector simultaneously reduces utility costs *and* reduces the risks ratepayers would otherwise face in underwriting novel and risky investments. In short, ensuring third-party ownership of DERs will allocate risk to the firms most able to bear it, while minimizing ratepayer risk, whereas utility ownership of DERs funded by ratepayers increases ratebase and the risk of under-recovery of utility costs.

i. Consumer Control of DERs Should be Preferred

NRG advocates a consumer-oriented approach to encouraging DER deployment, consistent with President Picker's guidance to "to enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner."[18] Indeed, the DER "triple value model" is the best way of making DER investments attractive to private investors. Direct utility command and control of DER operations makes implementation of such a consumer-oriented approach difficult, since doing so would eliminate (or seriously limit) the value the customer enjoys from its own facility, as well as potentially preventing it from accessing wholesale market revenues. In short, a consumer-oriented approach requires that *consumers* remain in charge of their own facilities and that DERs are treated, not as transmission (or distribution) elements subject to the control of the utilities, but customer facilities that can also support utility grid needs by responding to clearly defined price signals and other economic incentives in mutually agreed upon terms and conditions.

While such DER compensation issues are not central to how the distribution system itself should be planned, appropriate compensation will influence how customers and DER suppliers will deploy DERs, which in turn will influence the design, configuration and operation of the

[18] Guidance Ruling, at p. 3. Indeed, NRG notes that Assigned Commissioner Florio's recent Proposed *Decision Adopting an Expanded Scope, a Definition, and a Goal for the Integration of Demand Side Resources* in Rulemaking R.14-10-003 prominently features the customer in both the proposed definition of the term "integration of demand side resources" and the proposed goal of that rulemaking.

distribution system. Thus it is important to consider at least several basic approaches to DER compensation. One approach worth considering is creating a voluntary program that allows to DER hosts, or DER aggregators, to grant the utility a "call option" on specific DER services. These services could either be provided by a specific DER host, or more likely, could be provided by a DER aggregator with a fleet of such resources, that can provide the necessary services in a manner that is most consistent with the consumer's own objectives in owning the distributed resource.

SDG&E's DRP appears to partially contemplate this approach in its proposed demonstration project ("New Utility Business Model for DER Integration"), in which DERs locate on a capacity-challenged location in the distribution network in exchange for 1) accepting a new dynamic rate that more acutely aligns charging and discharging with specific grid needs and 2) allowing SDG&E to directly control the storage system's charge and discharge functions during a limited number of high-load hours annually.[19] SDG&E notes that "[w]hen coupled with some measure of limited, direct utility control, behind-the-meter storage targeted and deployed in these high-value locations could be aggregated to potentially defer conventional capital upgrades."[20] NRG supports the concept of creating additional incentives for DERs to locate at beneficial locations and anticipates that many DER hosts may elect to provide the utility with a call option on the facility's output, particularly during defined periods or conditions, sell services to the utility in exchange for favorable pricing. However, such transactions should be structured to leave the customer in charge of its energy decisions. This argues against *direct* utility control, which is not necessary to achieve the reliability benefits associated with the DER. Instead, the

[19] SDG&E DRP, at p. 75.

[20] SDG&E DRP, at p. 86.

utilities should simply provide pricing or other signals to the customers' facility or its service provider and rely on the contractual or tariff provisions to ensure that the customer or aggregator of resources will provide the requested services.

Indeed, the most innovative type of new DERs are the ones least suited to a command-and-control approach. Customers that integrate energy storage into their industrial processes, or that utilize combined heat and power to support heating and cooling load will be extremely unlikely to turn over direct control of their systems to the utility, but may be well-suited to responding to utility needs in limited, defined time periods or conditions. The periods of peak demand are exactly the times when the interests of the customer and the utility align best (*i.e.*, maximize DER output/minimize net draw from the grid. The eventual goal is to ensure that the financial benefits to the DER host or aggregator align with the utility's desire to have these resources operating during peak periods.

ii. If Necessary, Utility Procurement Should be Preferred to Utility Ownership

Similar to utility control over DERs, the Commission should also, as a general matter, prohibit regulated utility *ownership* of DERs. However, in the transition to a fully competitive and consumer-funded market, the Commission may wish to initially use utility *procurement* mechanisms to jumpstart the DER sector, comparable to how the Commission has used procurement policies to grow the utility-scale solar and storage sectors. On a limited basis, this same approach may also be effective in encouraging customer installation of certain DERs. Such procurement policies could be particularly effective in bridging the period between today and the time the Commission develops a distribution pricing model sufficient to make the "triple value model" discussed above a reality.

Even in the unusual circumstance where direct utility ownership or control of a customer-sited DER may be warranted, such as a DER upgrade that is uniquely and solely needed to defer network infrastructure, such a goal can be accommodated through the utility procurement model. However, such circumstances are likely to be relatively rare, and should not displace the compensation-for-service model discussed elsewhere in these comments.

ii. *The Commission should be Wary of "Pilot" Programs Providing Utilities Control or Ownership of DERs.*

NRG also urges the Commission to avoid regulated utility ownership of customer-facing DERs in the formative years of the distributed energy revolution. Allowing utility ownership would chill the ability of competitive entrants to participate in the formative stages of this industry if they are forced to compete against entities backing their investments with guaranteed rate recovery. Third-party investors and developers need the kind of expertise and engagement that only comes from actual participation in the DER marketplace. The clear 'least regrets' approach is to limit utility ownership at the outset, so as to create the best environment for third parties to invest.

C. A Multi-Layered Hierarchy is Useful in Optimizing DER Operations.

PG&E correctly recognizes that a hierarchical, layered, solution could result in effective dispatch of DERs. However, the three "optimization layers" proposed by PG&E, (1) customer, (2) feeder, (3) substation,[21] focus on the geographical dimension, they do not address the critical transactional element of aggregating what may be thousands or millions of DERs to provide useful distribution and wholesale market services. As the CAISO has recognized in its DERP proposal, such aggregators will play a critical role in unlocking the value of DERs for customers, the distribution system and the wholesale grid.

Clearly, it would be an overwhelming challenge for any single entity – be it a utility or a Distribution System Operator –to simultaneously control the operation of hundreds, if not thousands, of distributed resources.[22] Instead, NRG agrees with the many observers and experts who see the only real solution as the voluntary aggregation of DER customers-hosts by competitive DER aggregators, who will specialize in optimizing DER installment and operation in order to create the greatest customer value, including benefits derived from contributing to geographically differentiated distribution system and wholesale grid needs. While, in our view, utilities would not be aggregators, there are many important functions they would need to provide for such a system to work. Among these are planning the system that will support widespread customer-based DER deployment, identify with appropriate levels of granularity (where and when) the types of DER services that are needed, and develop and operate a system

[21] PG&E DRP, at p. 197.

[22] At some level, the operation of DERs for customer needs is simply another aspect of load uncertainty, which utilities have learned to predict and deal with effectively over the past 100+ years.

that will provide that information to elicit, and appropriate levels of compensation for, the services DERs provide. In this process, the competitive aggregator role would be analogous to the scheduling coordinator function utilized in the California wholesale markets to organize generator dispatch, or the "curtailment service provider" model used by PJM's very successful demand response program. This decentralized, competitively-funded layer, thus both fulfills a dispatch control need and provides substantial ratepayer and public benefits associated with deployment of DER-related investments.

Further, aggregation helps address the problem that, as several of the DRPs recognize, it is sometimes difficult to determine the level of reliability provided by an individual DER.[23] Realizing the reliability benefits of DERs requires moving beyond thinking of each individual DER as directly responsible for providing system stability. Instead, as with vehicle-to-grid services, the system will typically receive benefits from multiple aggregated resources collectively providing the needed distribution and wholesale market services in the most efficient manner. A variety of substitutable distributed resources being deployed by one or more aggregator of DERs, in quantities sufficient to provide the necessary distribution system attributes, would deliver superior value to both customers and the distribution system itself.

IV. COMPLIANCE WITH RULE 2.6

In compliance with Rule 2.6 of the Commission's Rules of Practice and Procedure, NRG states the following:

1. NRG agrees with the Commission's preliminary categorization of this proceeding as "quasi-legislative."

[23] PG&E DRP, at p. 195.

2. At this time, NRG does not believe hearings will be necessary. NRG recommends that the Commission use workshops as a mechanism for seeking public comment and input on the DRPs

3. NRG supports the proposed schedules set forth in the IOUs' applications which call for a final commission decision in this consolidated proceeding in the first or second quarter of 2016.

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