**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. (U39E)	Rulemaking 14-08-013 (Filed August 14, 2014)
And related matters	A.15-07-002 A.15-07-003 A.15-07-005 A.15-07-006 A.15-07-007 A.15-07-008

RESPONSES OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) TO LOCATIONAL NET BENEFITS ANALYSIS QUESTIONS PURSUANT TO JANUARY 8, 2016, ADMINISTRATIVE LAW JUDGE'S RULING

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Dated: January 26, 2016

Pursuant to the January 8, 2016, Administrative Law Judge's Ruling in this proceeding (January 8th Ruling), Pacific Gas and Electric Company (PG&E) provides its responses to the questions in the Ruling on Locational Net Benefits Analysis (LNBA) in this Distribution Resources Plan (DRP) proceeding. The Responses are provided in Appendix A attached to this pleading.

In addition to responding to the questions identified in the January 8th Ruling, PG&E believes that it is important for the Commission and parties to consider more generally how Distributed Energy Resources (DERs) will be procured to ensure the greatest benefits, for the lowest costs, for customers. Specifically, PG&E believes that an overall Locational Net Benefits Methodology (LNBM) should adopt and apply the all-source competitive solicitation principles that have been applied to PG&E's energy procurement under the Long Term Procurement Plan and Assembly Bill 57 (*i.e.*, Public Utilities Code Section 454.4) for the last decade. PG&E recommends that the Commission apply these commercial principles and protocols to the procurement of DERs for energy, capacity and distribution system deferral under PG&E's DRP. PG&E does not support administratively determined LNBM pricing under the DRP because such an approach could result in above-market prices and uneconomic costs to PG&E's customers. Rather, the Commission should adopt a competitive procurement process that will be open, transparent, and will result in decreased customer costs. PG&E's responses to the questions below are consistent with applying the competitive, all-source solicitation process to the LNBA for DERs.

Respectfully Submitted,

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Appendix A

PG&E Responses to Questions for Utilities and Parties with Alternative Proposals

1. **For utilities only: Describe any refinements you would make to your LNBA proposals in the applications based on comments received from other parties. Any other updates are also welcomed.**

   PG&E appreciates the opportunity to refine its LNBA proposal, and would like to make the following refinements:

   1) If a DER provides energy or any other product or service to a party other than PG&E, including through a California Independent System Operator (CAISO) market transactions, then any benefit or avoided cost associated with that product or service will not be attributed to that DER in PG&E's quantification of locational net benefits. With this refinement, PG&E's methodology will accurately account for DERs that may provide their energy and other services to parties other than PG&E, for example by bidding those resources into the CAISO energy markets and receiving compensation at the CAISO Locational Marginal Price (LMP) associated with that DER's location.

   2) PG&E will continue to use current, Commission-approved approaches to quantifying avoided costs wherever applicable per such approvals until directed otherwise by the Commission. This addresses the statement in the January 8th Ruling regarding use of the Distributed Energy Resources Avoided Cost Calculator (DERAC) tool pending any decision in the IDER proceeding

2. **For other party proposals only: Identify the locational granularity to use to evaluate the costs and benefits described in your approach (i.e., the line section, feeder, multiple feeders) if the proposal is different from the Guidance Ruling.**

   N/A.

3. **Identify the temporal granularity to appropriately evaluate costs and benefits described in your approach (i.e., daily, annually, etc.)**

   The level of granularity PG&E proposes is a function of the benefit from increased granularity for a given use case versus the cost and complexity of implementation. In general, PG&E uses models/forecasts that have the temporal granularity needed to capture variations relevant for the use at hand. For example, since energy prices vary significantly from hour-to-hour, if a resource's generation also varies from hour-to-hour, an hourly price forecast is more appropriate than a daily average forecast.

   From a distribution planning perspective, various levels of planning granularity are also required to ensure that the distribution system will have sufficient capacity to serve its end users. These levels of planning granularity will require different forecasting horizons. For example, a longer term (greater than five to ten years) outlook is needed to estimate the needs of a new neighborhood or new subdivision. Other facilities on the distribution grid, such as substation transformers and distribution feeders may require up to five years planning horizon. Specific line devices on a feeder may only require a one to five year planning horizon. The following table summarizes PG&E's proposed level of temporal granularity of models used to quantify a DER's impact and determine avoided or increased cost. It includes a page reference to PG&E's filed DRP.

	Locational Net Benefit or Cost Component	Granularity	Page Reference to July 1, 2015 DRP
1	Distribution Capacity	Hourly	66-71
2	Voltage & Power Quality	Hourly	71-72
3	Reliability & Resiliency	Hourly	72-73
4	Transmission	Hourly	73-74
5a	System or Local Area RA Procurement	Hourly	74-78
5b	Flexible RA Procurement	Hourly	78-79
6a	Generation Energy and GHG	Hourly	79-80
6b	Energy Losses	Hourly	81-82
6c	Ancillary Services	Hourly	82
6d	RPS Procurement	Hourly	82-83
7	Renewables Integration Cost	Hourly	83-85

4. **Describe the underlying data and assumptions for net load, load growth, and DER profiles, as well as the sources of deferred costs that would be used to determine avoided costs or other benefits. In particular, specify whether models and data sources are proprietary or public.**

The underlying data and assumptions for net load, load growth and DER profiles are described in PG&E's DRP in Chapters 2 and 7 and Appendix C, which are public. In most cases, PG&E uses load, generation and DER data and profiles from public sources such as CAISO's publicly-vetted Long Term Procurement Plan model and the California Energy Commission's (CEC) adopted Integrated Energy Policy Report (IEPR), both of which are described on pages 86-89. Where cost may be deferred, the source of that cost data is no different from whatever sources PG&E would normally use to obtain the applicable cost information.

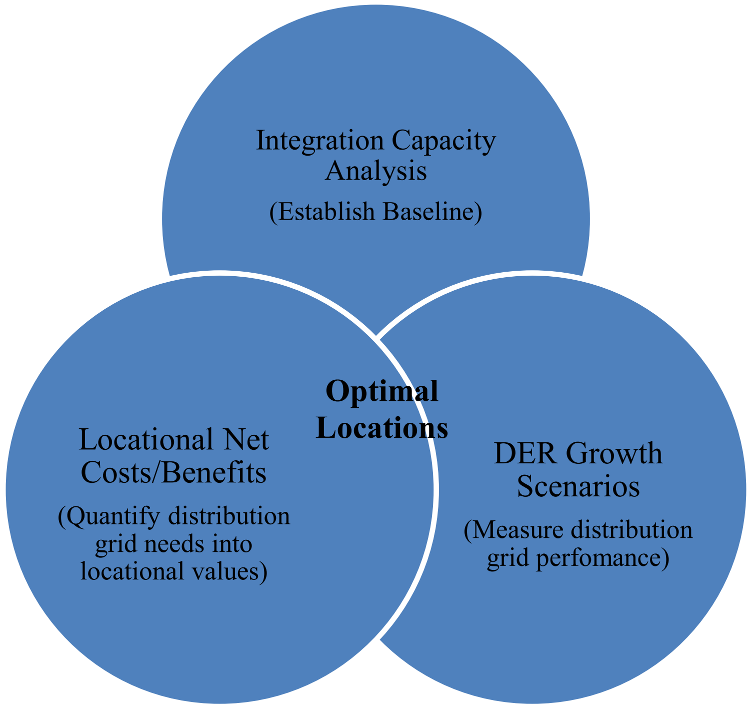
Certain of the models and data sources that support the DRP are proprietary, market-sensitive and/or confidential but available for review under appropriate non-disclosure agreements.

5. Describe how LNBA, together with the integration capacity analysis (ICA) and growth scenarios, would be used to identify "optimal location." In other words, how will the combined results be used to characterize the "optimality" of a location?

The ICA, DER growth scenarios and LNBA methodologies are key components to support the development of a Distribution Resources Plan and can be used to systematically identify "optimal locations" for deployment of DERs. Individually, each methodology enhances the current distribution planning process with additional information and insights about the characteristics of the existing and projected distribution grid performance. Integrating these methodologies into an integrated planning approach will identify "optimal locations" for DER deployment.

The following describes PG&E's approach for integrating these methodologies into distribution planning with the end result of helping identify and deploy DERs at "optimal locations. Specifically, PG&E envisions the following activities that integrate these proposed DRP methodologies:

- Establish Distribution Grid Baseline through ICA
- Incorporate Probabilistic DER Growth Scenario Analysis into Planning Analysis
- Quantify Locational Net Benefits (including incremental and avoided costs)
- Identify Optimal DER Locations



Establish Distribution Grid Baseline through Integration Capacity Analysis

ICA determines the available distribution capacity to host DERs before triggering distribution upgrades. ICA assesses the current distribution system's capacity baseline for hosting DERs, which can then be used to compare and rank higher versus lower DER integration capacity areas. This information can be helpful for DER developers in citing DERs and prioritizing distribution grid upgrades to accommodate projected levels of DER growth described further in the following section.

Incorporate Probabilistic DER Growth Scenarios into Distribution Planning

DER growth scenarios can provide a range of plausible DER adoption rates across the distribution system for the development of flexible long-term plans. Applying these DER growth scenarios into distribution planning will inform distribution planners on the locations of potential DER growth, DERs' impact on the magnitude and timing of potential distribution grid needs, and the potential use of DERs to defer distribution investment needs.

Quantify Locational Net Benefits & Net Costs

LNBA determines the DER locational value in terms of net avoided costs (benefit) or net incremental costs, which could be net positive or net negative based on the locational distribution grid needs at a particular location. These distribution grid needs would be determined through periodic distribution grid assessments that incorporate various DER growth scenarios (described above).

Identify Optimal DER Locations

In the final step, locations will be prioritized based on their locational "optimality" for DER deployment. Optimal locations for DERs can be determined in both a general sense during the planning process and a specific sense after the technical and economic feasibility of DERs for a specific location are determined. Using high-level information about the DER availability and potential benefits in one location versus another, optimal locations can be determined in a general sense in the planning process. With detailed information about how a particular DER (or DER portfolio) will impact the system at one location versus another, it is possible to determine optimal locations in a more specific sense. Either approach to determining optimal location requires a consideration of all the categories of potential benefit or cost to customers that are identified in PG&E's LNBA.

6. How can/should dynamic modeling used in ICA, together with modeling of DER portfolios, impact LNBA calculation or results? How will a dynamic ICA be represented in the LNBA?

Dynamic modeling can be interpreted to mean models that simulate changing impacts of a system over different hours considered in the analysis (e.g. the changing voltage profile as a generation profile changes through the day). It can also be interpreted to mean continuous updates of inputs to a model that capture changes to the system as resources are added or removed over time.

As with temporal granularity, cost-effective use of dynamic modeling is a function of the benefit achieved for a given use case versus the cost and complexity of implementation. In the context of LNBA, PG&E generally views the cost-effective use of dynamic simulations as beneficial. An energy price model or feeder model which only considers a snapshot in time, for example one hour out of the year, will not comprehensively capture the impacts of a DER on the system, and could, in fact, yield a positive net benefit in cases where the reality is negative or vice versa.

7. Describe and enumerate the grid services that could be evaluated in your approach.

Consistent with PG&E's DRP filing and subject to further analysis and demonstration, PG&E envisions that the following grid services may potentially be evaluated under this approach:

1. Distribution thermal capacity – DER output to manage equipment thermal loading levels to within their approval equipment ratings
2. Distribution voltage support – DER output to manage local steady state voltage levels to be operated within adequate voltage levels (e.g. Rule 2).
3. Distribution power quality (subset of voltage support) – DER output to manage local transient voltage levels to be operated within adequate voltage levels (e.g. Rule 2).
4. Distribution reliability – DER output that provides required power output to restore service to end-users or distribution facilities
5. Distribution resiliency – DER output that provides required power output to withstand major electric service disrupting events such as national catastrophes.

In addition to the listed distribution grid services that address distribution capacity and reliability needs in a specific location, PG&E's proposed LNBA methodology also includes value components for System/Local/Flexible Resource Adequacy, Generation Energy and greenhouse gas, losses, Ancillary Services, Renewable Portfolio Standard (RPS) and Renewables integration costs.

In summary, all net benefits (avoided and incremental costs), including distribution, transmission and generation functions need to be considered in determining optimal DER locations.

8. How should your approach be used in distribution system planning?

See Response to Question 5.

9. How does your methodology include costs associated with the potential need for common communications and control infrastructure required to support "smart" DER?

Common communications and control infrastructure, i.e. shared infrastructure that isn't attributed to a specific DER interconnection, which is required to enable a DER to provide grid services would not be included in the calculation of that DER's net cost. Such infrastructure may not always be required.

10. What types of forecasts are needed to support your approach? How are the forecasts integrated with the cost and benefit evaluation? What should be the time horizon of the forecast (i.e., one year, two years, five years, longer.)? Describe how changes of the LNBA value of a particular location over time would be evaluated.

As described in PG&E's response to question 5, the methodologies for ICA, DER growth scenarios and LNBA can be used to systematically identify "optimal locations" to deploy DERs. The following forecasts are needed to support PG&E's integration of DERs in its long term distribution planning process:

- **One, Five, and Ten Year Demand Forecasts**: Various levels of planning granularity are required to ensure a distribution system has sufficient capacity to serve its end users. These levels of planning granularity will require different forecasting horizons. For example a longer term five to ten year outlook is needed to project larger scale distribution facility issues, such as new substation development to accommodate new neighborhoods or subdivisions, which require extensive permitting and planning. Other facilities on the distribution grid, such as substation transformers and distribution feeders may require up to five years planning horizon, while some specific line devices on a feeder may only require a one year planning horizon.

- **DER and other Distributed Generation Forecasts**: DER and other distributed generation forecasts predict provide a range of plausible DER adoption rates across the distribution system for the development of flexible long-term plans.

> Incorporating these DER growth scenarios into distribution planning will inform distribution planners on the locations of potential DER growth, DERs' impact on the magnitude and timing of potential distribution grid needs, and the potential use of DERs to defer distribution investment needs.

The range of demand, DER and other distributed generation forecasts could then be used to develop planning scenarios for a particular area's LNBA, and support the development of flexible long-term plans.

PG&E Responses to Questions for Workshop

<u>Questions for All Parties</u>

1. **As discussed in Section 2 (Scope) of this Ruling above, the DRP Roadmap staff proposal (at p. 18) categorizes certain LNBA components as either non-location-specific (specifically: ancillary services, avoided GHG adder, avoided RPS purchases, renewables integration adder) or location-specific (specifically: line loss factor, avoided transmission and distribution capital and operating costs to provide capacity, voltage support, and power quality). Per the staff proposal, the non-location-specific components should be reviewed in the IDER proceeding, not the DRP.**
    a. **Do you agree with this general proposal?**
    b. **Why or why not?**
    c. **What modifications or clarifications would you make to the specific components staff has proposed to assign to one or the other category? Please explain.**

Per PG&E's "roadmap" written and oral comments, PG&E recommends that the non-location specific components be reviewed on a coordinated basis by stakeholders and Commission staff in the IDER, DRP and LTPP/Integrated Resource Plan proceedings, as well as CAISO transmission planning proceedings (for transmission assets) regardless of which proceeding is designated as the lead proceeding for procedural purposes.

It should be noted that all net benefits and costs, including distribution, transmission and generation functions, whether considered location-specific or not, must be considered in determining optimal DER locations given that DERs have different operating characteristics and energy profiles such that benefits or costs in one impact category can outweigh benefits or costs in another.

2. **Regarding the potential use of proprietary data and models:**
    a. **Is it acceptable for the LNBA to use proprietary data and models?**
    b. **If not, why not?**
    c. **What feasible modifications (e.g., data aggregation), if any, should be made to the methodology?**
    d. **What feasible alternatives (i.e., new LNBA proposals) by parties should the Commission consider to ensure that LNBA data sources and methods are made (wholly or in large part) available publicly to stakeholders and market participants?**
    e. **How can the desirable goals of accuracy and transparency best be balanced?**

a. Yes. PG&E anticipates using proprietary data and models to estimate locational avoided costs or benefits. Similar to existing practices used in procurement and critical infrastructure related activities, access to proprietary data and models is provided under appropriate non-disclosure agreements subject to different conditions and limitations applying to market and non-market participants.

b. N/A

c. For purposes of public disclosure of results from proprietary models or data sources, various methods such as aggregation, "masking," anonymization or randomization can be employed to allow public disclosure of the results without violating the confidentiality of the underlying model or data. The method to be used depends on the character and content of the particular data or model.

d. See response to c., above.

e. Proprietary data and models can be audited and reviewed by Commission staff and interested parties under appropriate non-disclosure agreements to ensure accuracy and transparency. *See, e.g.*, CPUC Rules 11.4 and 11.5.

3. What specific grid services (quantifiable or currently nonquantifiable) should the LNBA method include, as distinct from valuation methods that may be used in sourcing or procurement of grid services? To the extent possible, please provide a list of grid services and rationale for why each grid service should be

a. valued in the LNBA and/or

b. **compensated (or alternatively, required without compensation) in a potential DER sourcing mechanism.**

a. The table below, copied from page 65 of PG&E's DRP summarizes the components of PG&E's proposed LNBA, which are included per the Commission guidance ruling:

#	Component	PG&E Definition
1	Sub-Transmission, Substation and Feeder Capital and Operating Expenditures (Distribution Capacity)	Avoided or increased costs incurred to increase capacity on sub-transmission, substation and/or distribution feeders to ensure system can accommodate forecast load growth
2	Distribution Voltage and Power Quality Capital and Operating Expenditures	Avoided or increased costs incurred to ensure power delivered is within required operating specifications (*i.e.*, voltage, fluctuations, etc.)
3	Distribution Reliability and Resiliency Capital and Operating Expenditures	Avoided or increased costs incurred to proactively prevent, mitigate and respond to routine outages (reliability) and major outages (resiliency)
4	Transmission Capital and Operating Expenditures	Avoided or increased costs incurred to increase capacity on transmission line and/or substations to ensure system can accommodate forecast load growth.
5a	System or Local Area RA	Avoided or increased costs incurred to procure RA capacity to meet system or CAISO-identified Local Capacity Requirement (LCR)
5b	Flexible RA	Avoided or increased costs incurred to procure Flexible RA capacity
6a	Generation Energy and GHG	Avoided or increased costs incurred to procure electrical energy and associated cost of GHG emissions on behalf of utility customers
6b	Energy Losses	Avoided or increased costs to deliver procured electrical energy to utility customers due to losses on the T&D system
6c	Ancillary Services	Avoided or increased costs to procure ancillary services on behalf of utility customers
6d	RPS	Avoided or increased costs incurred to procure RPS eligible energy on behalf of utility customers as required to meet the utility's RPS requirements.
7	Renewables Integration Costs	Avoided or increased generation-related costs not already captured under other components (*e.g.*, Ancillary Services and Flexible RA capacity) associated with integrating variable renewable

#	Component	PG&E Definition
		resources
8	Any societal avoided costs which can be clearly linked to the deployment of DERs	Decreased or increased costs to the public which do not have any nexus to utility costs or rates
9	Any avoided public safety costs which can be clearly linked to the deployment of DERs	Decreased or increased safety-related costs which are not captured in any other component

PG&E has proposed a method of quantifying each component in its DRP, with the exception of the last two, which, per the definitions above, do not have a nexus to utility costs or rates.

b. Those LNBA components which are not quantified and do not have a nexus to rates should not be used to determine DER compensation, since the benefits of a DER should accrue to those who pay for that DER's compensation. For the remainder, the quantification methods used in the LNBA are not generally appropriate to use for purposes of determining compensation to DERs. The purpose of LNBA is to identify optimal locations for DERs on the distribution grid, not to set utility rates or define compensation for DERs.

DER sourcing and compensation for DER services can be and is accomplished in a variety of ways, including competitive procurement and "all-source" solicitations.

Compensation for DERs in any solicitation context should be designed to achieve the objectives of the DER programs, including directing DER deployment to specific optimal locations that are deemed cost-effective, feasible and reliable, while at the same time providing maximum value to PG&E customers at the least cost possible.