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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.15-07-006

(NOT CONSOLIDATED)

In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	A.15-07-005 (Filed July 1, 2015)
And Related Matters.	A.15-07-007 A.15-07-008

PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E)
PROPOSED DISTRIBUTION PLANNING AREA AVOIDED COST METHODOLOGY
PURSUANT TO DECISION NO. 17-09-026

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Dated: December 5, 2017

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Pursuant to Ordering Paragraph 15 of Decision (D.) 17-09-026, Pacific Gas and Electric Company provides its proposal for modeling and/or methodological approaches that enable Locational Net Benefit Analysis to calculate Distribution Planning Area-level avoided Transmission & Distribution values for input into the Distributed Energy Resources Avoided Cost Calculator. PG&E's proposal is attached as Appendix A.

Respectfully submitted,

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Appendix A

PG&E Proposal: Distribution Planning Area-Specific Transmission and Distribution Capacity Avoided Cost for use in the Distributed Energy Resources Avoided Cost Calculator

Summary

PG&E proposes an incremental change to the current DERAC methodology for distribution capacity avoided cost to extend the geographic granularity from the current climate zone level to the distribution planning area (DPA) level. In addition, PG&E proposes to bifurcate the distribution avoided cost into "base" and "project specific" components: the base component can be applied to both targeted and non-targeted DER programs while the "project specific" component would be available only to DER programs that can show they meet right place, right time, right availability and right certainty to effectively defer the identified project. PG&E points to the "(D)istribution-factor" analysis that is used to support design and evaluation of targeted demand response programs as being a useful model that can be applied to all targeted DER programs.

PG&E believes it is premature to make a specific proposal regarding development of a geographically differentiated transmission capacity avoided cost at this time, but is open to working with CAISO and other stakeholders to determine whether a geographically differentiated transmission capacity avoided cost is supported by data and consistent with CAISO and FERC guidance and rules. PG&E notes that even if a geographically differentiated avoided cost was supported by the data, CAISO and other stakeholders would need to develop a "(T)ransmission-factor" to determine whether a DER program could reasonably defer the local transmission project, and ensure the avoided cost and cost-effectiveness model is consistent with CAISO and FERC guidance and rules.

PG&E makes no specific proposal here regarding adjustments to the avoid cost metrics for impacts of non-autonomous DER adoption by customers. Instead PG&E suggests that this issue, which has impacts across multiple proceedings, be taken up as part of the next IEPR proceeding.

Regulatory Background

The Distribution Resources Plan proceeding's Decision 17-09-026 states: "Within 60 days of the issuance of this decision, the Investor-owned Utilities are ordered to file and serve proposals for modeling and/or methodological approaches that enable Locational Net Benefit Analysis to calculate Distribution Planning Area-level avoided Transmission & Distribution values for input into the [DERAC][1] Calculator."[2] This decision also discusses several key aspects of these Distribution Planning Area-level (DPA-level) avoided Transmission and Distribution (T&D) values: they should extend thirty years to

[1] The DERAC model is a commission-adopted, public model developed by Energy & Environmental Economics that produces indicative projections of hourly avoided costs.

[2] Ordering Paragraph 15. D.17-09-026 was issued on 10/06/2017.

match the life of Distributed Energy Resources (DER) that they might be used to evaluate; they should capture uncertainty in deferrable projects that might exist both within and beyond the distribution planning horizon, and they should reflect a planning scenario that doesn't assume future adoption of DER which have not yet been evaluated for cost-effectiveness and approved.

Prior Commission Decisions related to energy efficiency and demand response (DR) have also directed the Investor Owned Utilities to develop location-based avoided costs and cost effectiveness methodologies that support the design and evaluation of geographically targeted programs. In the Energy Efficiency 2015 and Beyond Rolling Portfolios proceeding (R.13-11-005), IOUs were directed to "work with Commission Staff to determine how much of a departure from default PV[Gen] and PV[TD] values in cost calculators is appropriate to capture the locational value for such projects."[3] Likewise, in the Demand Response OIR 2013 (R.13-09-011), the Commission observed that: "part of the value of a DR program is its ability to avoid [T&D] investment and upgrades to California's electricity system. These avoided T&D costs are an input to DR cost-effectiveness (C-E) analysis. The DR C-E Protocols allow the value of these avoided T&D costs to be adjusted to reflect the extent to which a DR program actually avoids T&D costs."[4] As a result, IOUs worked with stakeholders to update the DR C-E protocols to provide further guidance on the "D" factor analysis that supports geographic targeting of demand response programs for the purpose of capturing geographically differentiated transmission and distribution avoided costs. These updates were approved in 2016 by the Commission in Resolution E-4788.[5]

PG&E Policy and Planning Objectives

PG&E seeks to ensure consistency where relevant and applicable across IDER, DRP, IRP, and DER Program proceedings with respect to design and evaluation of cost-effective DER programs[6] that can provide transmission and distribution services, by following these guiding principles:

- Use consistent, well-defined, and transparent cost/benefit analysis
- Use observable market indicators rather than model results whenever possible
- Provide compensation only when identified benefits are realized by DER programs
- Avoid duplicative compensation
- Inform procurement of DERs by modeling results and competitive solicitations with local cost and non-cost factors

[3] D 14-10-046: Decision Establishing Energy Efficiency Savings Goals and Approving 2015 Energy Efficiency Programs and Budgets, OP 13

[4] Decision 15-11-042 -- Decision Addressing the Valuation of Load Modifying Demand Response and Demand Response Cost-Effectiveness Protocols – the Commission observed (OP 7)

[5] Available Here: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K107/163107029.PDF

[6] "programs" in this context refers to a planned, coordinated group of activities and procedures for the specific purpose of increasing the uptake of DERs by customers beyond what would have occurred in the absence of the program.

PG&E-Specific Proposal for DERAC Update

The current DERAC model calculates geographically differentiated distribution avoided costs at a climate-zone level for PG&E's service territory. PG&E calculates a DPA-level distribution capacity marginal cost consistent with the PG&E Division-level distribution capacity marginal cost in the GRC Phase II filings.[7] The consulting firm Energy and Environmental Economics (EThree) translates the *Division-level* distribution capacity marginal cost into an indicative Climate Zone-level distribution capacity avoided cost in the current DERAC tool. PG&E proposes to improve upon this existing framework to develop an indicative Distribution Planning Area (DPA)-level locational avoided distribution costs that support design and evaluation of location-specific DER programs.

For PG&E, "Distribution Planning Area" is a designation that was historically used for load forecasting and is currently used for purposes of work allocation. PG&E's DPAs were originally designed, to the extent practicable, to capture areas of the distribution system that have strong electrical ties internally while having little electrical connection to surrounding areas. DPAs were also designed to capture areas with common load distribution, load growth rate and primary voltage level, to the extent practicable.[8] This definition may be unique to PG&E, as other utilities have unique geographies, loads, and histories impacting distribution system build-out.

The diagram below (Figure 1) explains the current DPA-level distribution capacity marginal cost model. The key inputs and calculations in this model are conceptually equivalent to the key inputs and calculations supporting the current LNBA model for calculating distribution benefits. Based on insights from the LNBA working group, PG&E proposes to make two adjustments to the model shown in Figure 1 to bring it into greater conformity with the LNBA modeling:

1. Instead of using the projected DPA load growth in KW as the denominator in the calculation, the LNBA-based model would use the projected DPA capacity deficiency in KW as the denominator, since overall DPA-level load growth is not a good proxy for the magnitude of a specific capacity deficiency associated with a planned upgrade.

2. PG&E proposes to determine the projects included in the 5-year projects forecast list for calculating distribution capacity marginal cost according to the initial distribution infrastructure deferral framework (DIDF) screening criteria.

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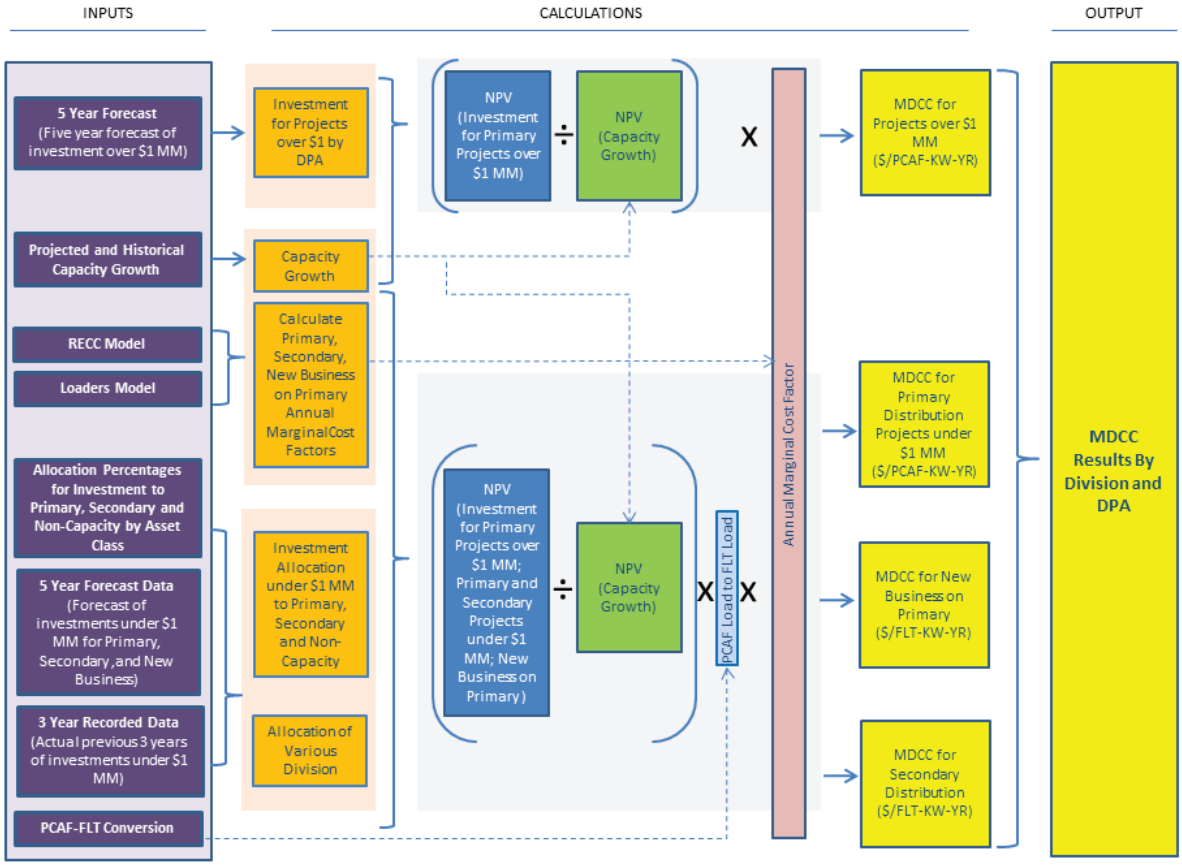
[7] PG&E's distribution territory is divided into approximately 250 DPAs which collectively comprise approximately 20 Divisions.

[8] Additional description of PG&E's development of DPAs is available at page 5-2 of PG&E's 2017 GRC Phase II Marginal Cost Testimony. PG&E divides its distribution system into specific geographic areas or Distribution Planning Areas (DPA). For many years PG&E forecast distribution 22 expansion based on DPAs and analyzed load and capacity at the DPA level. Ideally, a DPA has: uniform load distribution; uniform load growth rate; a single primary distribution voltage; strong distribution ties among substations inside the area; and no ties to substations outside the area. Although ideal DPAs are not encountered in practice, DPAs are defined as nearly as practicable to that ideal. Currently, there are 245 DPAs in PG&E's service territory.

Figure 1

Flow Chart for Development of Division and DPA Level Distribution Capacity Marginal Costs



In addition to the two adjustments described above, PG&E is open to exploring with the CAISO and other stakeholders potential methods of calculating an indicative, geographically-differentiated transmission capacity marginal cost if it is consistent with PG&E's and the CAISO's policy and planning objectives and compliant with FERC guidance and rules. As stated previously PG&E's preference is to rely on observable market data whenever possible and to avoid duplicative compensation. As such, PG&E's preference would be to look to CAISO data to determine if there is an observable differential locational value for the provision of transmission services and how that differential value is currently monetized before attempting to develop a shadow price proxy.

Proposed Bifurcation of the DPA-Level Distribution Avoided Cost

PG&E proposes, for the initial indicative use of DPA-level avoided cost, to bifurcate the DPA-level avoided cost into a "base" component and "project specific" components. The base component is derived from the aggregation of projects in the Division that are under $1 million in estimated cost,

including distribution capacity additions that are not associated with identified projects (so-called "emergent work"). A "project-specific" component is based on individually identified projects in the DPA that are estimated to be over $1 million each.

Table 1, below, shows the type of DPA-level data that underlies the climate-zone level differentiated distribution avoided costs that are in the current DERAC model for PG&E. All DPAs have a relatively stable distribution capacity marginal cost for the aggregation of projects under $1 million. For example, all the DPAs within the Central Coast Division have a "base" distribution capacity marginal cost of $16.78 PCAF/KW-year[9] while the system average distribution capacity marginal cost for aggregated projects under $1 million is $17.38 PCAF/KW-year. Looking across all 245 PG&E DPAs, the standard deviation on the "base" distribution capacity marginal cost is approximately $2.38 PCAF/KW-year. PG&E proposes that it is reasonable for the "base" component to be used as the avoided cost in the evaluation of both targeted and non-targeted DER programs.

TABLE 1: DPA-Level Distribution Capacity Marginal Costs

Division	DPA	Primary Projects over $1 Million $/PCAF-KW-YR [A]	Primary Projects under $1 Million $/PCAF-KW-YR [B]
CENTRAL COAST	CARMEL VALLEY 12KV	$ -	$ 16.78
CENTRAL COAST	GONZALES	$ 80.15	$ 16.78
CENTRAL COAST	HOLLISTER	$ -	$ 16.78
CENTRAL COAST	KING CITY	$ 89.58	$ 16.78
CENTRAL COAST	MONTEREY 21KV	$ -	$ 16.78
CENTRAL COAST	MONTEREY 4KV	$ -	$ 16.78
CENTRAL COAST	OILFIELDS	$ -	$ 16.78
CENTRAL COAST	POINT MORETTI	$ -	$ 16.78
CENTRAL COAST	PRUNEDALE	$ -	$ 16.78
CENTRAL COAST	SALINAS	$ -	$ 16.78
CENTRAL COAST	SANTA CRUZ AREA	$ -	$ 16.78
CENTRAL COAST	SEASIDE MARINA	$ -	$ 16.78

As shown in column 3 of Table 1, the "primary projects over $1 million" component of PG&E's DPA-specific marginal distribution capacity cost calculation has much greater variation than the base component. Out of PG&E's 245 DPAs, only about 30% have one or more identified projects over $1 million in PG&E's 2017 GRC filing. These locations with identified projects over $1 million would be incorporated in the DPA-specific avoided costs to signal targeted DER programs. Table 2, below, shows

[9] Distribution Peak Capacity Allocation Factors (PCAFs) are used to measure coincidence with the local peak across a number of peak hours rather than a single peak hour. An extensive discussion of PG&E's distribution PCAF methodology is given in Chapter 10 of PG&E's 2017 GRC Phase II Testimony.

an illustrative calculation of distribution avoided cost separated into the two components for the Gonzales and Hollister DPAs.

Table 2
Example of DPA Level Distribution Capacity Avoided Cost $/KW-year

	Gonzales DPA	Hollister DPA
Base $PCAF/KW-year	**16.78**	**16.78**
Project Specific $PCAF/KW-year	**80.15**	**0.00**

PG&E proposes that in order for a DER program to capture the "project specific" avoided cost, the program must show that it can provide the DER services that meet the right place, right time, right availability, and right certainty criteria as described in the updated demand response "D-factor" protocol documents approved by the Commission in Resolution E-4788.

DPA-Level T&D Avoided Cost Metric in Context

Development of a DPA-level T&D illustrative avoided cost metric is necessary but not sufficient to support the design and evaluation of a cost-effective DER program. Equally important is the cost-effectiveness evaluation and competitive solicitation framework that assess whether the proposed targeted DER program is able to capture all or part of the avoided cost metric. PG&E proposes that, consistent with the Demand Response Programs Cost-Effectiveness Protocols Update approved by the Commission in Advice Letter Resolution E-4788, DER Programs that wish to claim the DPA-specific distribution marginal cost in the DERAC should be required to show that they meet the "Right Time, Right Place, Right Availability, Right Certainty" criteria as follows:

- **Right Time**: DER program can be deployed in time to defer some or all of the costs of planned or needed distribution system upgrades (i.e., before local conditions become severe enough to require upgrades)
- **Right Place**: DER programs both 1) exist in areas where additional distribution capacity is needed (i.e. are located in areas where load growth would result in a need for additional delivery infrastructure but for the DER program) and 2) can also be relied upon for local T&D equipment loading relief (e.g., can be dispatched just in the local area, not only system-wide).
- **Right Certainty**: There is sufficient certainty that the DER program, either as a stand-alone resource or in combination with other resources, can provide the demand reductions in sufficient quantity and longevity to defer upgrade costs. For example, there must be a sufficient number of customers and the appropriate types of DERs to provide a reasonable level of certainty that needed demand reductions can be provided.
- **Right Availability**: DER program will be available when needed. This is a similar calculation as for the Demand Response cost-effectiveness A-factor, although specific to the local area need that is driving the infrastructure project. It should take into account that for DERs to be able to avoid sub-transmission and distribution investment, the DERs must be available to reduce load consistent with the need in the local area.

PG&E reiterates here it is equally important for stakeholders to discuss and develop both the DPA-level avoided T&D costs and the cost-effectiveness methodology that will determine what portion of those avoided costs can be captured by a locational DER program. The T&D avoided cost metric is an input into the cost-effectiveness model and, therefore, must be designed to be consistent with that larger framework that includes local distribution load forecasts, plans, and the results of competitive solicitations where applicable.

Incorporation of Unplanned Distribution Capital Avoided Costs Within and Beyond the Planning Horizon

PG&E proposes, consistent with current practice in the DERAC model for transmission and distribution avoided costs, that the base avoided costs can be escalated at a reasonable rate of inflation over the appropriate time horizon for program cost effectiveness evaluation, with regular updates to these avoided costs, as required by D.16-06-007. As discussed earlier, the base component incorporates the estimated "emerging work" for each DPA based on historic trends.

PG&E believes that the bifurcation of avoided costs into "base" and "project-specific" components, along with other procurement criteria, will best support the development of targeted DER programs and send the signal to DER program developers the time sensitive nature associated with capture of the project-specific avoided cost over $1 million. At the same time, the "base" component of the avoided cost explicitly recognizes that local deployment of DERs that reduce local area load or increase local area generation may have the more general effect of deferring smaller infrastructure projects that have not been specifically identified in the distribution planning studies.

PG&E's proposal on Adjustments for "Autonomous DER Growth"

PG&E defines "autonomous DER growth" as DER adoption that is naturally occurring absent the program/tariff/incentive being measured for cost-effectiveness. As such, PG&E believes the use case of design and evaluation of targeted DER programs requires only that the targeted DER programs being evaluated be excluded from the load growth projections.

PG&E's proposal provides a methodology for placing locational avoided distribution capacity into the distributed energy resources avoided cost calculator. The proposal does not provide a methodology for performing a counterfactual analysis (whether a distribution capacity project would have been avoided but for the targeted DER program) to determine program cost-effectiveness. A counterfactual analysis depends on the assumed DER growth scenarios and what is deemed 'autonomous' DER growth.

PG&E suggests that the open question on what portion of the DER growth scenarios is autonomous vs. non-autonomous and how that should be treated in long-term planning studies for generating a locational T&D avoided cost metric, should be addressed as part of the larger discussion on State Agencies coordination on the development and use of DER adoption scenarios in long-term planning studies including the Integrated Energy Policy Report, Integrated Resource Planning studies, Transmission Planning studies and Distribution Planning studies. This type of effort is likely to be

contentious and time consuming. The Joint State Agencies should consider the formation of a working group to study these issues further.

Inclusion of DER Integration Costs

PG&E proposes that integration costs be included as part of the cost-effectiveness calculation. Since integration costs are technology specific, this evaluation would be applied outside of DERAC. PG&E recommends further discussion on these integration costs and methodologies in the workshops. For a starting place, PG&E proposes the following definitions for DER integration cost components, which would be discussed by the working group:

- Interconnection Cost: Cost caused by a single DER interconnection
- Grid Modernization: Cost caused by high penetration broadly (could be a net cost)
- Bulk Grid Integration Cost: Cost currently captured in the Renewable Integration Cost Adder, as defined in the RPS proceeding.

Locational Transmission Avoided Costs

As stated previously, while PG&E is open to discussing with the CAISO and other stakeholders methods to develop a location-specific transmission avoided cost that would support design and evaluation of targeted programs, PG&E is not proposing a specific methodology to accomplish that at this time. PG&E's preference is to rely on observable market data whenever possible and to avoid duplicative compensation. PG&E's preference is to look to the CAISO market data to determine if there is an observable differential locational value for the provision of transmission services and how that differential value is currently monetized before attempting to develop a shadow price proxy. If a locational transmission avoided cost is supported by the analysis, then development of "T-factor" criteria (parallel to the D-Factor criteria describe above) that would be required for a DER program to show that is has the right place, right time, right availability and right certainty to capture the location specific transmission avoided cost under prevailing CAISO and FERC guidance and rules. In the meantime, the Joint IOUs have submitted a long-term LNBA refinement proposal for locational generation capacity based on Local Resource Adequacy which captures the value of reducing peak load in certain transmission-constrained areas.

Aggregation to IRP supply curves

PG&E supports using consistent methodologies across proceedings to achieve state climate goals. The ability to translate local distribution benefits and costs into system-level curves will require cross proceeding coordination. PG&E recommends the Commission facilitate a series of workshops to develop this model as part of the common resource valuation framework being developed in the Integrated Resource Plan (IRP) proceeding (16.02-007) in collaboration with IRP staff. These workshops would be in tandem with the Joint Agencies work on DER growth scenarios, discussed above.

Conclusion

PG&E's proposal focuses on what it believes is the highest value and most accessible near-term use case for an indicative DPA-level transmission and distribution avoided cost that can be calculated for use in DERAC. That initial use case is to support the design and evaluation of targeted DER programs. PG&E recognizes that it may be uniquely positioned to develop a DPA-specific distribution avoided cost for this use case in the near-term because the current distribution avoided cost in the DERAC for PG&E is already an aggregation of the DPA-level avoided cost information. However, additional use-cases that go beyond support for design and evaluation of targeted DER programs and the associated development of locational T&D avoided cost metrics may take significantly more time to develop. Furthermore, periodic adjustments to the current DPA-level distribution capacity marginal cost model inputs will be necessary to bring that model into even greater conformity with insights gained during the development of the LNBA metric over the past few years.

It is important for stakeholders to have a clear understanding that development of a targeted DER cost-effectiveness framework is of equal importance to development of the DPA-level T&D avoided cost metric. While this proposal provides addresses the DPA-level avoided cost metric, the ultimate goal of this process is the implementation cost-effective targeted DER programs. PG&E proposes that the "D-factor" analysis developed in the targeted demand response programs proceedings may be the appropriate cost-effectiveness model for this purpose.

PG&E is open to discussing with the CAISO and other stakeholders methods to develop a location-specific transmission avoided cost. While PG&E makes no specific proposal at this time, our guiding principles suggest using observable market data rather than an administratively determined shadow prices. PG&E is also concerned that proposals could result in duplicative payment for differential transmission value.

PG&E makes no specific proposal regarding development of autonomous vs. non-autonomous DER growth scenarios for use in developing DPA or system-wide T&D cost-effectiveness evaluation. Defining DER growth scenarios into autonomous and non-autonomous components for use in long-term planning studies such as the IRP, the TPP and the DRP will likely involve a long and contentious process that may be best coordinated by the Joint State Agencies (CPUC, CEC and CAISO) over the course of the next Integrated Energy Policy Report cycle.

PG&E looks forward to feedback on this submitted proposal and working with the Energy Division staff and other stakeholders over the next several months to assess whether the proposal can be implemented for future DERAC updates.