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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.	Rulemaking 14-08-013
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)	
Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005
And Related Matters.	Application 15-07-007 Application 15-07-008

ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES

Summary

This *Ruling* seeks comments on the Energy Division *White Paper on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values*

(White Paper). The objective of the Energy Division *White Paper*, and the issue to be resolved in the Rulemaking (R.) 14-08-013 Distribution Resource Planning (DRP) Proceeding is to determine how to estimate the value that results from using Distributed Energy Resources (DER) to defer transmission and distribution (T&D) infrastructure. An important subsidiary issue is identifying the appropriate level of locational granularity for calculating those values, which may be applied as a single value across each utility service territory, or it may vary by location.

This *Ruling* and *White Paper* are being served jointly to the DRP R.14-08-013 as well as the Integrated Distributed Energy Resource (IDER) R.14-10-003 proceeding service list. The purpose is to make parties to both proceedings aware that the methodology for avoided T&D avoided costs will be decided in the DRP proceeding and (if approved) will be applied into the Avoided Cost Calculator (ACC) as a major update and not be determined separately in the IDER proceeding. This serves to clarify that there will not be two decision-making pathways on avoided T&D for the ACC. Parties to the IDER proceeding who are also parties to the DRP proceeding who wish to comment on the record for this *White Paper* should become parties to the DRP proceeding.

Energy Division will hold a workshop to discuss this proposal on July 8, 2019. Parties are directed to file comments on the amended proposal and respond to specific questions contained in this *Ruling*. Opening Comments shall be filed and served no later than June 21, 2019. The Energy Division shall plan the workshop agenda in part to address the issues raised in Opening Comments as well as those identified in the *White Paper*. Replies shall be filed and served no later than 21 days following the workshop.

1. Background

In Decision (D.)17-09-026, the Commission adopted the Locational Net Benefits Analysis (LNBA) to calculate a location specific avoided cost of DERs in accordance with Public Utilities (Pub. Util.) Code § 769. However, D.17-09-026 found that the LNBA methodology was not appropriate for calculating the avoided costs of T&D for DERs procured through Commission mandated programs, such as the energy efficiency (EE) portfolio or net energy metering (NEM). On December 20, 2018, Energy Division staff held a workshop to discuss party proposals for avoided T&D, and presented a proposed approach developed by Energy Division staff. The attached *White Paper* provides additional clarification of the issues for resolution, the staff proposal, and recommendations for location granularity of different use cases. The presentations from the December 20, 2018 workshop have also been attached for reference.

The staff proposal is not intended to be a fully developed and executed methodology, but rather serves as a starting point for consideration of whether avoided cost calculator methodology should be updated to calculate avoided T&D costs based on the forecast data provided in the Grid Needs Assessment (GNA) and Distribution Deferral Opportunities Report (DDOR).

2. Questions for Parties

Please indicate whether you agree or disagree with staff's assessment and recommendations as presented in this paper. If you disagree with any aspect of staff's proposal and recommendations, please provide a detailed rebuttal argument and propose an alternative. An alternate methodology for calculating avoided T&D must be detailed, specific, and actionable.

1. Do you agree with staff's interpretation of the task at hand?
2. Please comment on staff's proposed revisions to the definitions of important terms and proposed framework for specifying use cases.
3. Please comment on staff's assessment of the uncertainty for each category of value and use case, and their recommendations for the appropriate location granularity for the various use cases.
4. Considering staff's preliminary analysis of Pacific Gas and Electric Company's (PG&E's) 2018 GNA, please comment on staff's recommendations regarding the methodology for estimating:
   a. Specified distribution deferral value
   b. Unspecified distribution deferral value
   c. Specified transmission deferral value
   d. Unspecified transmission deferral value

IT IS RULED that:

1. Opening Comments shall be filed and served no later than June 21, 2019.
2. Replies shall be filed and served no later than 21 days following the workshop.

Dated June 5, 2019, at San Francisco, California.

/s/ ROBERT M. MASON III
Robert M. Mason III
Administrative Law Judge

ATTACHMENT A

White Paper

Energy Division Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values

Executive Summary

The objective of this white paper, and the issue to be resolved in the R.14-08-013 Distribution Resource Planning (DRP) Proceeding is to determine how to estimate the value that results from using Distributed Energy Resources (DER) to defer transmission and distribution (T&D) infrastructure. An important subsidiary issue is identifying the appropriate level of locational granularity for calculating those values, which may be applied as a single value across each utility service territory, or it may vary by location.

PU Code Sec. 769 (AB 327, 2013) directed IOUs to file with the Commission distribution resources plans (DRPs) that among other things evaluate locational benefits and costs of distributed energy resources (DERs). "This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation."[1]

Currently, the Avoided Cost Calculator (ACC) is used to inform the cost-effectiveness of Commission demand-side programs and tariffs, such as NEM, including the avoided costs of T&D. Today the ACC has a single avoided distribution value in each of the SCE and SDG&E territories based on the marginal cost of distribution from the GRC. The PG&E avoided cost of distribution value is also based on the marginal cost of distribution from the GRC and is further broken out by climate zone. The ACC has a single avoided transmission value in the PG&E territory and a zero value in SCE and SDG&E territory.

The Commission adopted the Locational Net Benefits Analysis (LNBA) methodology in the Track 1 Decision of the DRP proceeding (R.17-09-026) in 2017 in order to calculate a locationally specific avoided cost of DERs. The Track 1 Decision found the LNBA methodology developed by the LNBA working group to be useful for calculating the avoided costs for specific distribution deferral projects that the IOUs were considering for competitive solicitation. The decision did not find the LNBA methodology was appropriate for calculating the avoided costs of T&D for DERs procured through Commission mandated programs, such as the EE portfolio or NEM. Thus, the Commission in D.17-09-026 ordered further action to address it, in the context of further developing a "cost-effectiveness use case" for the LNBA methodology. Parties submitted proposals on methods of calculating unspecified T&D deferral value on December 5, 2017. A Ruling posing specific questions on parties' proposals was issued on March 29, 2018. Parties provided comments on the proposals on April 30, 2018. Staff subsequently held a workshop on December 20, 2018. The workshop agenda and presentation materials are included as Appendix B.

To help the Commission move further towards resolving this issue, this Staff Proposal offers:

1) a set of updated definitions of important terms and concepts;
2) a refinement of the definition of "use cases" previously described in D.17-09-026;

[1] PU Code 769 (b) (1)

3) a proposed approach for estimating unspecified distribution and transmission deferral value;
4) an overall set of recommendations; and
5) a set of questions intended to complete the record needed to enable the Commission to adopt a policy on this issue via Decision.

The underlying concepts at issue in the DRP Proceeding are inherently abstract and complex. As a result, it is easy for deviations to arise in how different terms are used by different individuals or parties. This, in turn, can lead to misunderstandings and frustrate progress in developing solutions. Therefore, staff found it was necessary to more clearly define these concepts and recommendations prior to seeking input from parties, to ensure that parties have the same understanding of the proposals under consideration. Furthermore, this white paper proposes a concrete methodological approach to calculating distribution deferral, provides a preliminary analysis applying the methodology, and provides recommendations for how the methods should be applied to different types of use cases. However, staff's recommendations are intended to serve as a starting point for a discussion with parties, rather than a complete and fully developed methodology.

Additionally, the paper does not intend to significantly alter current CPUC and CAISO methodologies of calculating the specified distribution and transmission deferral value. The paper does comment on how these related concepts fit into the overall framework of distribution and transmission deferral value.

1. Updated Working Definitions

Due to the complexity and challenges described above, terms and concepts promulgated in prior working group, staff, and/or Commission forums may merit revision in light of information and experience gained through subsequent activity. To that end, staff proposes below an updated set of working definitions of certain DRP terms and concepts. These definitions apply throughout the rest of this document (unless otherwise noted) and are proposed for general future use in the DRP Proceeding.

Rather than being listed individually, many of the definitions below are provided as pairs of contrasting, but sometimes confused concepts.

Non-targeted DER growth: The CEC develops a forecast of DER growth in the Integrated Energy Policy Report (IEPR), which the IOUs disaggregate to establish the circuit level forecast for distribution planning. The IEPR forecast includes two types of DER growth:

- Non-targeted DER growth refers to an increase in DERs over time that results from Commission-ordered policies, programs, or tariffs that are not locationally targeted to defer transmission and distribution upgrades.[2]
- "Naturally occurring" DER growth is also included in the demand forecast, which results from customer adoption of DERs that are not supported by any tariff or incentive payments. This

[2] The concept of "autonomous DER growth" was referenced in D.17-09-026 on pg. 46 to explain the avoided cost use case for the LNBA. Since this term has alternate definitions in other proceedings, we will cease to use the term in this proceeding and will instead refer to the term "non-targeted DER growth."

category includes DER growth resulting from codes and standards[3], the development of which are sometimes supported by ratepayer funding, and which may vary by climate zone within the state.

Targeted DER Procurement: This refers to DER procured in response to a specific identified need at a specific location. The DRP Distribution Investment Deferral Framework (DIDF) is one example of targeted DER procurement, but there may be other examples as well.

Avoided costs vs. cost effectiveness: Avoided costs are costs of providing electricity (e.g., building power plants, buying natural gas) that would have been incurred if not for some action taken, such as the installation of an energy efficiency measure or unit of DER equipment. They represent a source of value, or benefit, associated with that action. Cost effectiveness, on the other hand, refers to the relationship between the benefits and the costs of the action. Avoided costs are the inputs used to estimate the benefits in the cost effectiveness calculation.

Note: These concepts are sometimes confused in discussions of LNBA. LNBA is an approach to adding up several different avoided costs, or benefits, of DERs in a particular location. LNBA addresses avoided costs but does not address cost effectiveness. The confusion arises because a given avoided cost of a DER in a particular location could be negative. That means that instead of a benefit, the avoided cost would actually be an incurred cost. The "net" part of LNBA reflects the fact that multiple streams of avoided costs are added together, one or more of which may be negative, resulting in a net value. The fact that LNBA can involve adding up both positive and negative values can make it seem similar to a cost effectiveness calculation. However, LNBA explicitly and deliberately does not consider the costs of the DER itself, which is a foundational component of a cost-effectiveness calculation.

Avoided T&D: This phrase refers to avoided or deferred transmission and distribution infrastructure. It is sometimes used as a shorthand for transmission and distribution deferral value. See also "deferral vs. avoidance."

DERAC vs. ACC: These two names refer to the same underlying tool. Avoided Cost Calculator (ACC) is the name used in the Integrated Distributed Energy Resources (IDER) and DER resource proceedings, whereas Distributed Energy Resource Avoided Cost (DERAC) is the name that became common in the DRP proceeding. Going forward DRP will use the ACC terminology to avoid confusion. The CPUC's ACC reflects the avoided costs of electricity and are modeled based on the following components: generation energy, generation capacity, ancillary services, transmission and distribution capacity, environment (i.e., avoided greenhouse gases), and avoided renewable portfolio standard. The avoided cost model is annually updated to improve the accuracy of how benefits of demand-side resources are calculated. The most recent update was completed in 2018. For more information go to the CPUC's Cost Effectiveness webpage.

Counterfactual forecast vs. unmanaged forecast: Both terms refer to a load forecast from which forecasts of the adoption of load-modifying distributed energy resources, such as energy efficiency, demand response, battery storage, rooftop photovoltaic (PV), and electric vehicles, have been removed,

[3] Codes and Standards (C&S) are categorized as both naturally occurring and Commission-ordered policies. The C&S program administered by the IOUs contributes substantial analysis to the adoption of Title 24 Code as well as federal appliance standards, for which the IOUs receive credit toward their savings, based on individual analysis of IOUs' contribution to the adoption of each standard.

for the most part. The term "unmanaged forecast" is more frequently used in the context of the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) process as synonymous with their "base forecast," whereas the term "counterfactual forecast" has been used in the DRP proceeding.[4]

There is a small difference in the two concepts. The counterfactual forecast in DRP reflects the removal of only those DER load impacts that are the result of Commission policies, including tariffs like Net Energy Metering (NEM).[5] In contrast, the unmanaged forecast reflects the removal of all incremental DERs, regardless of whether the load impacts result from Commission policies or other policy initiatives, such as CEC or federal efficiency standards that would have happened regardless of Commission-approved funding.

A counterfactual forecast is also different from another type of counterfactual analysis with which it is sometimes confused. For the purposes of evaluating the influence of different actions (such as programs or measures) that have already taken place, an important question is: what would have happened if not for that action? This kind of question is outside the scope of the DRP proceeding entirely. The DRP proceeding is concerned only with the counterfactual future, not the counterfactual past. The relevant question that drives interest in the idea of a counterfactual forecast in the DRP proceeding is: what would happen to load in the future in the absence of any Commission-driven DER procurement policies (including tariffs)?

Deferral vs. avoidance ("deferral value"): DERs may be used to defer upgrading a piece of equipment by reducing the growth of load that would otherwise be expected to drive the need for an upgrade. If the DER allows a permanent deferral of an upgrade, then that equipment is *avoided*. Note that existing equipment will eventually need to be replaced, so what the DER is avoiding is specifically the upgrade that would otherwise occur. Avoidance is a special deferral case where the length of the upgrade deferral is equal to or greater than the expected useful life of the underlying equipment.

Note: A related but conceptually separate value is the difference between the cost of the equipment that must eventually be installed and the cost of the equipment that would otherwise need to be installed if not for the DERs. The phrase "deferral value" is used as an umbrella term to refer to the sum of these two types of value.

Planning vs. Procurement: Planning and procurement are distinguished by whether compensation is centrally involved. Procurement refers to activities that involve compensation intended to add or make an electrical resource available to the grid (including on the customer side of meter), including tariffs, solicitations, or incentive programs. Planning refers to activities that involve the establishment of high level goals or targets that do not directly result in compensation from ratepayers to resource providers. Examples include: energy efficiency or demand response potential and goals studies, Reference System Plan portfolio optimization in Integrated Resource Planning (IRP).

Note: Planning and procurement activities may not always indicate that the same set of resources represents the least cost or greatest value solution for meeting an identified need. Deviations between

[4] A nuance is that the CEC base forecast includes a small amount of so-called "committed" energy efficiency.
[5] Practically speaking, a DRP counterfactual forecast might also exclude certain types of Commission policies that are implemented for reasons less directly dependent on cost-effectiveness.

the resources indicated by a planning analysis and those actually procured can arise when different approaches to valuing resources are used in each process. Even when the underlying methodologies are identical, however, procurement outcomes may still deviate from the outcomes projected in planning exercises due to differences between forecasted resource costs (or other assumptions) and actual prices offered in the context of a proposed market transaction.

Specified deferral value: Value associated with deferring the purchase and installation of specific infrastructure that has been identified by a utility or California Independent System Operator (CAISO) as needed for grid reliability, resiliency or safety. Deferral value is generally associated with capacity-related projects whose need can be affected by changes in peak demand.

Value associated with deferring specific infrastructure identified as needed for other purposes (i.e. GHG reduction, renewable portfolio standard (RPS) compliance, or economic benefits) is a conceptually separate type of value and is excluded from this definition but not from consideration in cost-effectiveness calculations. What this means is that a Request for Offer (RFO) for DERs purchased to defer a planned distribution investment should evaluate the bids by determining their deferral value plus any and all values recognized by the Commission.

Unspecified deferral value: Value associated with deferring the purchase and installation of generic infrastructure that has not been specifically identified by a utility or by the CAISO as needed for grid reliability, resiliency, or safety, but is estimated to be needed. This value reflects the concept that not all grid needs can be anticipated with perfect foresight, and some portion of those unanticipated grid needs could be satisfied by DERs.

Relationship of specified and unspecified deferral value: Specified deferral value has been most commonly associated with the Distribution Investment Deferral Framework (DIDF), and unspecified deferral value has been most commonly associated with providing inputs to the ACC which is then used to inform the evaluation of the cost effectiveness of various Commission-supported demand-side programs such as NEM. There is nothing theoretically preventing the combination of these two separate sources of value. The more obvious example is DIDF. While the primary source of value in a DIDF procurement is the specified deferral value stated in the RFO, the valuation of DER bids must also include any unspecified deferral value as defined by Commission policy. Non-targeted DERs will have some unspecified deferral value but depending on their location may also have some specified deferral value.

Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR): In D.18-02-004, the Commission required the IOU to submit an annual GNA filing each year wherein the IOUs provide a comprehensive list of distribution facilities and forecasted grid needs which inform the Distribution Deferral Investment Report (DDOR). The DDOR presents a list of candidate distribution deferral opportunities that result from an initial deferral screening process. Pursuant to a recent ALJ Ruling the GNA and DDOR are filed together on August 15 each year and now include transmission grid needs that are subject to CPUC jurisdiction.[6]

[6] *Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process,* May 7, 2019.

Locational Net Benefit Analysis (LNBA) v. Avoided T&D inputs for the ACC: The concept of the LNBA was defined to meet the requirements of PU Code 769 b(1), which requires the IOUs to submit a proposal to "Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation." D.17-09-026 adopted an LNBA methodology that could be applied to two of the three use cases identified in the decision as further discussed in the next section. The decision did not approve the use of LNBA for the purpose of calculating values for the avoided cost calculator. To avoid future confusion, "LNBA" will be used to refer to the methodology developed and adopted in D.17-09-026 and this paper will propose the method to develop avoided T&D cost inputs for the ACC.

2. Clarifying the Framework for Specifying Use Cases

Ordering Paragraph (OP) 14 of D.17-09-026 articulates three use cases for LNBA:

> "The Locational Net Benefit Analysis use cases for: 1) Public Tool and Heat Map; 2) prioritization of candidate distribution deferral opportunities as part of the Distribution Investment Deferral Framework; and 3) providing location-specific avoided transmission and distribution inputs into the Integrated Distributed Energy Resources Distributed Energy Resources Avoided Cost Calculator for cost-effectiveness evaluation, informing Distributed Energy Resources incentive levels, and other applications, are adopted."

Elsewhere in the Decision, the use cases are described in similar, though not identical ways (see p. 42, COL 5, and OP 15). In these various instances throughout the Decision, the description of the LNBA use cases sometimes inadvertently implies a conflation of four different categories that would be useful to explicitly distinguish from each other: values, methodologies, tools, and use cases. Proposed definitions of these categories, as they apply within DRP, are as follows:

- **A value** is a benefit, usually in the form of an avoided cost, that DERs provide when they are constructed and used.
- **A method, or methodology** is a set of mathematical or conceptual relationships that prescribe how to develop a set of output information from a set of input information.
- **A tool or model** is software in which a specific methodology is implemented.
- **A use case** is a human activity in which a tool, a methodology, and a value may be used.[7]

[7] Under a more nuanced framework an activity might be more precisely called an "ultimate" use case. A "proximate" use case could be a methodology, tool, or activity – whatever the value, methodology, or tool is immediately used in. A "complete" use case would be the full set of proximate use cases leading up to the ultimate use case. The one presented above is deliberately simpler.

A simple way to articulate the relationship between these categories is as follows: A value is represented as a number within a tool that implements a methodology in order to develop information for an activity. The use case for the value, methodology, or tool is the activity that it informs.[8]

Examples of each category are presented in the tables below.

Table 1. Examples of Values

1	Specified Distribution Deferral Value
2	Unspecified Distribution Deferral Value
3	Specified Transmission Deferral Value
4	Unspecified Transmission Deferral Value

Table 2. Examples of Methodologies

1	LNBA
2	Integrated Capacity Analysis (ICA)

Table 3. Examples of Tools or Models

1	Avoided Cost Calculator (ACC)
2	LNBA Tool
3	ICA online map
4	A production cost simulation model
5	A capacity expansion model
6	Proprietary procurement valuation tools
7	A power flow model

[8] Note that a value may be an input or output of a methodology. For example, using these definitions, it is logical to refer to a methodology for developing an avoided cost, as well as to a methodology that uses an avoided cost as input to calculate cost-effectiveness.

Table 4. Examples of Use Cases

	Planning
1	DER developer business development[9] (i.e. Public Tool and Heat Map)
2	DIDF prioritization of candidate deferrals[10]
3	Integrated Resource Planning (IRP)
4	Energy efficiency (EE) potential and goals studies
5	Demand response (DR) potential study
	Procurement[11]
	Tenders/Solicitations
1	DIDF Competitive Solicitation Framework RFOs
2	Transmission Planning Process (TPP) RFOs
3	Energy storage RFOs
4	NEM tariffs
5	IDER DER sourcing tariff (if adopted)
	DER Program Budget
6	EE portfolio budget setting
7	DR program and budget proposals

As shown in Table 4, use cases fall into two groups: planning and procurement. As described in the updated definitions above, planning and procurement are distinguished by whether compensation is centrally involved. In addition, Table 5 presents the possible levels of locational granularity of the T&D deferral, which must be determined for the different use cases.

Table 5. Examples of Possible Levels of Granularity

specific unit of equipment
node (pole, line segment)
circuit/feeder
Substation/feeder bank
distribution planning area
transmission zone
transmission access charge territory
utility territory

[9] Identified in D.17-09-026 as the first use case, Public Tool and Heat Map
[10] Identified as the second use case in D.17-09-026
[11] The third use case identified in D.17-09-026 is expected to provide the inputs for the avoided cost calculator, which informs the non-RFO forms of DER procurement, including NEM tariffs, EE and DR portfolio budgets.

Purpose of Clarifying Use Cases

One of the challenges in addressing the issue of developing locational transmission and distribution deferral values has been in interpreting the three uses cases ordered by D.17-09-026. Using the four categories described above to interpret OP 14 helps to clarify the task at hand and to reveal some of the difficulties in completing it.

Ordering Paragraph 14 identified the use cases for what we have now defined as a methodology ("Locational Net Benefit Analysis"). Recall that use cases for values, methodologies, and tools are activities. However, the description of the first use case uses dicta that specify a tool, rather than an activity. The second use case identified in the LNBA Decision indicates that the activity that should be understood as the use case in this instance is "to identify potential optimal locations for deploying DER based on candidate deferral opportunities identified in the distribution planning process, along with detailed information about the required DER attributes necessary to achieve such deferrals."[12] This could be considered a planning type of use case, since it revolves around identifying locations for project development, rather than compensating projects, but the LNBA working group also intended for this use case to enable compensation to DER developers for building DERs in locations that would defer distribution upgrades, although it did not explicitly consider what the procurement mechanism should be.[13]

The description of the second use case in OP 14, unlike the first use case, does explicitly describe a specific activity, consistent with the new categories: "prioritization of candidate distribution deferral opportunities as part of the Distribution Investment Deferral Framework." Although DIDF includes a solicitation process, this part of the process only involves identifying possible parameters for targeting procurement and does not drive procurement itself. As a result, the prioritization use case is considered planning, whereas the RFO process itself is considering procurement. These categorizations of different phases of the DIDF process are reflected in the table above.

The description of the third use case marks a shift from the paragraph's overall focus on the use cases for the LNBA methodology to something else. Instead of identifying an activity for which the LNBA should be used, it suggests that LNBA should itself be modified to include specific values, namely "location-specific avoided transmission and distribution inputs," that could then also be added to a specific tool ("…Avoided Cost Calculator"). That latter tool would then be used in three different use cases that are at least somewhat recognizable as activities according to our new definition:

1. Cost effectiveness evaluation
2. Goals and budget setting
3. Potentially informing [DER] incentive levels, if Commission decides to implement a new tariff structure[14]

Interpreting this part of the paragraph using the updated definitions presented in this paper suggests the following actions:

[12] Pg. 42 of D.17-09-026
[13] Pg. 26 of Locational Net Benefit Analysis Working Group Final Report
[14] This potential application would be considered in the IDER proceeding, R. 14-10-003

Action 1: Identify appropriate methodologies to produce two new deferral values (transmission and distribution deferral values).

Action 2: Develop a modeling tool to produce updated locational net benefit values across the electrical system that reflect the new deferral values.

Action 3: Implement actions 1-2 in a way that allows the locational net benefit values to be incorporated into the ACC methodology and tool, as well as other potential methodologies and tools.

Action 4: Implement actions 1-3 in a way that enables the ACC and other methodologies and tools that use the underlying deferral values, to be deployed in a wide range of use cases, including both planning and procurement.

The first two use cases described above do require additional refinement, and proposals for refinement were reported in The LNBA Working Group Long Term Refinements Final Report. The focus of this paper, however, is to address issues associated with third use case: providing location-specific avoided transmission and distribution inputs into the Integrated Distributed Energy Resources Avoided Cost Calculator for cost-effectiveness evaluation, informing Distributed Energy Resources incentive levels, and other applications.

3. Challenges to Developing an Avoided T&D Methodology

The application of the updated definitions and new use case framework gives us a more precise, explicit, and complete description of the task before us. It also helps us to understand more clearly some of the challenges in completing the task.

For example, the wide range of use cases contemplated in action 5 above, which span both planning and procurement use cases, can make it seem difficult to determine the appropriate methodology to be developed in action 1. For example, it is conceivable that methodologies appropriate for planning activities may not establish an acceptable basis for allowing cost recovery for procurement activities.

The nature of the deferral value to be calculated in action 1 creates another challenge. Although the distinction was not explicitly made in prior rulings or decisions, SCE’s proposal for estimating locational transmission and distribution deferral value helpfully introduced the terms “specified” and “unspecified” to refer to the two types of deferral value.

SCE’s proposal characterized the third LNBA use case (under the definition of D.17-09-026) as being related to the unspecified type of deferral value. However, using our new framework for thinking about use cases, it is clear that D.17-09-026 implicates many different use cases for transmission and distribution deferral value. That raises the question of whether the same type of deferral value is appropriate for all of those use cases.

In consideration of these challenges, it may be tempting to try to evaluate all of the proposals submitted by parties for estimating locational transmission and distribution deferral value for each of the use cases listed in Table 4 to determine which proposals may be appropriate for which use cases. To reduce the scope of the challenge, the Commission could also explicitly prioritize one or more specific use cases of interest. For example, the Commission could prioritize the development of avoided T&D values specifically for approving EE program budgets. Another option would be to conclude that no feasible options are available and to leave the T&D deferral values currently used in the ACC unchanged.

Implications of the Uncertainty of Locational Avoided T&D Values

When considering how the avoided T&D values will be applied to the planning and procurement use cases, a closer examination of the uncertainty involved in the two types of deferral helps point toward a simpler solution. Specified deferral value derives from the identification of clearly defined future grid needs and infrastructure investments that a utility is likely to make, subject to additional analysis to reflect the extent to which the need may be met by DERs instead. Each of the processes involved in calculating specified deferral value involves some level of uncertainty. It is possible that the identified future grid need might not actually come to pass even without the proposed investment. It is possible that the infrastructure investments that are identified may not meet the need as well as anticipated. It may be that a piece of equipment may not be as deferrable with DERs as originally envisioned. These are uncertainties inherent to estimates of specified deferral value as well as distribution grid planning. Unspecified deferral value derives from determinations that are likely even more subject to change and error than those underlying specified deferral value. For unspecified deferral value, conditions may suggest the possibility of a future grid need, but there is an even greater chance that the need may never come to pass, the timing of the need may change, the type of infrastructure suitable for meeting the need may change, or that the technical suitability of DERs for deferring that infrastructure may change.

At the same time, it does not seem to be reasonable to conclude that, outside of the DIDF process, no DERs ever contribute to deferring distribution or transmission infrastructure in any location. The problem is that it is difficult to predict which of the potential future needs across the grid will eventually materialize as concrete, specified, deferrable projects. In other words, unspecified deferral value very likely exists to some degree, but the location of that value is extremely uncertain.

4. Energy Division Proposal to Calculate Unspecified Transmission and Distribution Deferral Value

At the December 20, 2018 workshop, Energy Division staff presented a straw proposal to calculate the unspecified distribution deferral value based on Grid Needs Assessment (GNA) data. This proposal is intended to serve as a starting point for discussing the approaches used to quantify the avoided costs of transmission and distribution rather than a fully developed methodology. The proposal for calculating distribution deferral involves simplifying assumptions and that need to be addressed in order to develop a complete methodology, and once adopted in the DRP proceeding, the method would need to be incorporated into the avoided cost calculator. Energy Division staff is seeking input on whether the GNA serves as the most reasonable starting point for calculating the impact of non-targeted DERs on the deferral of distribution, and whether, in light of this analysis, what locational granularity should be applied within the avoided cost calculator for unspecified deferral.

In addition to ED staff's proposal, PG&E presented a proposal at the workshop that offers a way to incorporate both unspecified and specified distribution deferral value. Under PG&E's proposal, unspecified deferral value is not locationally specific, while their specified deferral value is locationally specific. PG&E's proposal does not provide an analysis of the distribution impacts of the non-targeted DERs embedded in the forecast. This type of approach mirrors that in use in New York, as presented in the December 20 workshop by E3. SCE presented a proposal on calculation of avoided transmission values. These presentations have been attached to the white paper in Appendix B.

Energy Division Proposal to Calculate Unspecified Avoided Distribution Costs Based on GNA Data

Energy Division staff proposes to estimate the total value of distribution deferrals resulting from non-targeted DER growth using existing data from the utilities' General Rate Case (GRC), GNA and the Distribution Deferral Opportunity Report (DDOR). To better explain the proposed methodology, staff has developed a simplified, preliminary analysis using PG&E's 2018 GNA and DDOR data.[15] The results of this analysis are not intended to be applied as actual avoided costs of distribution, but are provided to demonstrate how the GNA and DDOR data may be used to estimate avoided costs of distribution. Staff anticipates the methodology incorporated into the avoided cost calculator would address the shortcomings to this preliminary analysis, which are listed in the following section.

To facilitate explanation of this approach, we have separated the calculation into a price (*P*, the average value of deferring distribution system upgrades, expressed as the average $ per kW of distribution upgrade capacity) and quantity (*Q*, amount of distribution system upgrades deferred by DERs) component. In its simplest form, avoided costs are calculated as *P*Q,* which results in a single, system level distribution deferral value for the non-targeted DERs that are embedded in the demand forecast, in $/kW. Since marginal costs are built up from several components, some resolution is needed on what aspects of an IOU's marginal distribution capacity costs can be applied to this calculation as well as to further clarity on the source of this data. The approach to calculate the quantity (*Q*) is broken down into four sequential parts, described below. Each step is illustrated with a sample calculation of six circuits from the PG&E's load data.

Part 1: Estimate the capacity of distribution system upgrades deferred by DERs *(Q)*

1. **Calculate the Counterfactual Forecast:** The circuit-level counterfactual load (as defined in the updated working definitions) and distribution capacity deficiency can be derived from the data in the GNA by adding the circuit-level DER forecast to the circuit-level load. The circuit-level counterfactual forecast stems from GNA data on the capacity deficiency on each circuit to 2024, based on the latest data (i.e. the 2018 DIDF cycle). Adding back in the forecasted DERs that are 'assigned' to each circuit can produce an estimate of counterfactual load: the load that would have occurred if future non-targeted DERs are removed from the forecast. In this simplified analysis, DERs are being treated as additive to demand. Caveats and limitations to the simplified analysis are discussed in the following section.

[15] The staff's preliminary analysis could not be conducted with SCE and SDG&E's 2018 GNA, because it did not include facility loading or forecasts data for circuits that were not overloaded.

Table 6. Sample Circuit-level Calculation of Counterfactual Forecast

Circuit ID	2022 Demand Forecast (MW)	DER Forecast in 2022 (MW)				2022 Counterfactual Forecast (MW) *(Demand + DERs)*
		EE	DR	PV	Storage	
1	1.76	0.05	0.01	0.12	0.00	1.94
2	0.30	0.01	0.00	0.00	0.00	0.32
3	10.53	0.29	0.01	0.64	0.00	11.47
4	11.69	0.39	0.04	0.86	0.00	12.97
5	10.49	0.31	0.02	0.83	0.00	11.65
6	12.07	0.40	0.03	0.91	0.00	13.41

Source: Sample set of circuits from PG&E's 2018 GNA

2. **Calculate capacity overload for counterfactual forecast:** The capacity overload that is deferred by DERs embedded in the forecast can be estimated from the facility capacity and loading percentage provided in the GNA, by calculating the facility loading percentage as a ratio of counterfactual forecast to the facility capacity. This calculation is consistent with how the loading percentage is derived for the actual planning forecast. All circuits that are above 100% loading are considered overloaded. However, only circuits that are overloaded in counterfactual forecast, and not in the actual planning forecast are counted as deferred by non-targeted DER growth (DER growth that is embedded in the forecast). In the sample calculation below, Circuits 4 and 6 would be overloaded in 2022 if the DER forecast is not realized.

Table 7. Capacity Overload for Sample Circuits in Counterfactual Forecast

Circuit ID	Facility Rating (MW)	2022 Demand Forecast	2022 Facility Loading (%)	2022 Counter-factual Load (MW)	Counter-factual Facility Loading (%)	6. Circuit Overload MW
(source)	*GNA Data*	*GNA Data*	*GNA Data*	*Step 1 result*	*CF load /facility rating*	*CF load – facility rating*
1	7.12	1.76	24.7	1.94	26.76	0.00
2	4.49	0.30	6.7	0.32	7.24	0.00
3	12.34	10.53	85.3	11.47	88.58	0.00
4	11.82	11.69	98.9	12.97	104.93	0.58
5	12.19	10.49	86.1	11.65	91.26	0.00
6	12.19	12.07	99.0	13.41	103.92	0.48

The sum of capacity overloads in PG&E's counterfactual forecast is 91 MW.

3. **Estimate the percentage of distribution capacity overloads that lead to deferred distribution upgrades:** For this preliminary simplified analysis, staff is only calculating a system level quantity for deferred distribution capacity. The challenges in calculating a locationally specific value are addressed in the next section. Staff proposes to base this assumption on the ratio of such capacity overloads identified in the GNA to those capacity overloads that are potentially deferrable as

identified in the DDOR. This resulting percentage is a proxy for distribution capacity upgrades that can be deferred by DERs, which can be applied to the capacity overload of each circuit that was calculated in step 1.

Table 8. Percent of Distribution Capacity Overloads that Require Distribution Upgrades

		Total # of Feeders	Feeder Capacity (MW)	*Source*
a	Total capacity overloads on system	183	2,328	*GNA*
b	Overload addressed by load transfer	144	1,799	*GNA*
c	Planned Investments	39	528	*DDOR*
d	**Ratio of overload capacity to require distribution upgrades**	**21%**	**23%**	*=c/a*
	Counterfactual Forecast			
e	Capacity overloads in counterfactual forecast	208	91	*sum of circuit overloads in Step 2*
f	**Planned Investments deferred by DERs embedded in forecast**	44	21	*=e*d*

The estimated deferred capacity of the overloaded circuits can be used to arrive at a system-level quantity of distribution capacity that is deferred by DERs embedded in the forecast. (i.e.,*Q).*

Part II: Estimate the value of deferring distribution system upgrades *(P)*

4. **Calculate the marginal cost of the deferred distribution upgrades**. Staff proposes that the marginal cost is based on the total planned investments in the DDOR filing, (DDOR_MC $/kW-yr) DDOR MC is the sum of the total cost of planned investments in the DDOR filing divided by the capacity deficiency that the planned investments are mitigating. This value is expected to be higher than the marginal cost of distribution in the GRC, which divides the cost of distribution by all load growth in the system.[16]

5. **Calculate system-level avoided distribution costs:** For an initial, simplified estimate of the locational avoided distribution capacity cost, we multiply *P* by the amount of deferred distribution capacity for each circuit calculated in the previous step (i.e., *P*Q*). To do so, we add the Q across all the circuits and multiply the result by P (ie. marginal cost of distribution, and then divide by the sum of the 10-year forecasted level of DERs forecasted in all the circuits (as expressed in megawatts (MW) for each circuit). This results in a single, system level distribution deferral value for the non-targeted DERs that are embedded in the demand forecast, in $/kW.

   ED staff will decline to make the calculation in step 4-5, since the result may be misconstrued to represent the actual avoided cost of distribution. A more comprehensive analysis is necessary to

[16] Staff recommends that the DDOR MC is only used if it is higher than the GRC MC value.

address the limitations in this simplified analysis in order to calculate an accurate value, as discussed below.

Limitations of Staff's Preliminary Analysis and Implications for Finalizing an Avoided Distributions Cost Methodology for the Avoided Cost Calculator

This preliminary analysis is not intended to calculate the actual avoided costs results because this analysis is limited by several analytical challenges and methodological limitations that need to be improved and/or addressed to finalize the methodology:

1. **The 2018 GNA was incomplete.** The 2018 GNA data is not comprehensive, since D. 18-02-004 allowed the IOUs to submit their available data and did not require the full GNA to be submitted until 2019. In the 2018 GNA, only PG&E's dataset included the full list of distribution circuits, including those that are not overloaded, which is necessary to run to run a preliminary analysis. Even PG&E's dataset is limited to feeders and does not include all equipment on each feeder. This limitation can be addressed in a future iteration of the analysis, after the 2019 GNA has been submitted that includes a complete set of forecasted grid needs and planned projects, which could potentially increase the total capacity of deferred equipment.
2. **DER production shapes must be applied.** To accurately remove DERs from the forecast, DER production shapes need to be applied to the load shape of the demand forecast, since DERs may be generating or saving at less than their full capacity during the circuit's peak period. PG&E applies the Peak Capacity Allocation Factor (PCAF) to their marginal cost, and a similar calculation would be needed for SCE and SDG&E. Considering that approximately half the DER forecast is PV and a small portion of PV generation occurs during system peak, a significant portion of the DER MW capacity will not reduce the peak load on the feeder.[17] As a result, Energy Division's preliminary results are likely to overestimate the impact of DERs on the circuit level forecast. This limitation would need to be addressed in a future iteration of the analysis by applying load shapes to the counterfactual loading.
3. **Naturally-occurring DERs should remain in the counterfactual forecast.** The DERs in the counterfactual forecast include two types of DER growth from the IEPR forecast: DER growth driven by Commission-mandated incentives and tariffs, and naturally occurring DER growth. To accurately account for the impact of non-targeted DER growth on avoided T&D, only DER growth driven by Commission-mandated incentives and tariffs should be removed from the IEPR forecast, because the purpose of the avoided cost calculator is specifically assessing the value of these incentives and tariffs. Making this adjustment would require a breakout of DERs by driver in the GNA and would result in reducing the impact of DERs on distribution deferral.
4. **GNA's five-year forecast horizon should be extended.** The impact of DERs to defer distribution upgrades accrue over the long term, while the GNA is limited to the forecast horizon that is necessary for distribution planning. For actual distribution planning, investments are only planned on a five-year forecast horizon. For estimates in the avoided cost calculator, the horizon should be extended to estimate DER deferral value for the cumulative impact of DERs over their expected useful life. Roughly speaking, the number of identified projects should be multiplied by 4 to reflect

[17] Peak demand has shifted to evening hours due increasing penetrations of solar generation. As a result, PV generation has ceased to reduce peak system demand.

long-run 20 years of DER impact. This would likely result in increasing the impact of DERs on distribution deferral.

5. **It is uncertain which circuits require distribution upgrades vs. no-cost load transfers.** A substantial portion of the distribution capacity overloads are addressed through no-cost reconfiguration of the distribution circuits. The determination of which circuits require distribution upgrades and which circuits are addressed through load transfers requires iterative power flow analysis and the judgment of qualified distribution engineers and planners. It appears to be exceedingly difficult to predict with a high degree of confidence which specific circuits that appear to be overloaded in a counterfactual analysis would require distribution upgrades.
6. **Preliminary analysis is based on the current load forecast trajectory, with low load growth.** Even with DERs removed from the forecast, the trajectory of load growth is relatively low for the next five years. Deferred distribution upgrades may increase in the future if building and transportation electrification drive future load growth. High electrification scenarios could potentially be applied as a sensitivity case to the proposed methodology to evaluate the possible impacts of building and transportation electrification growth on distribution deferral.

Thus, to develop a locationally specific estimate of the distribution deferral of DERs, an estimate of distribution capacity would need to be derived based on assumptions regarding which circuits would have required distribution upgrades in the absence of DER growth. Step 3 of staff’s analysis only calculates a system level avoided cost of distribution. In order to determine the distribution avoided cost on a locational basis in the avoided cost calculator, the methodology will need overcome the lack of predictability of which specific grid needs can be addressed with load transfers and which require new, and potentially deferrable, infrastructure. This informs staff’s current recommendation discussed later in the paper to keep the unspecified avoided distribution value uniform across each IOU territory.

All of the other above limitations will also need to be addressed to improve the methodology.

Findings from Energy Division’s Preliminary Analysis of Distribution Deferrals in PG&E Territory

Considering these limitations, Energy Division completed its initial calculation using PG&E’s 2018 GNA data in order to understand the potential *scale* of deferred distribution capacity embedded in the forecast. Based on PG&E’s 2018 GNA, 1,700 MW of DERs are forecasted to be installed and an estimated 90 MW of additional capacity overloads is avoided due to the non-targeted DER deployment by 2022. In the context of the overall distribution system capacity, this impact is small: PG&E’s forecasted demand in 2022 is 23,000 MW; PG&E’s overall distribution system capacity is 33,000 MW.

Out of the 3,300 feeders in PG&E’s territory, 203 of them would have been overloaded, but are not now, due to the DERs embedded in the forecast. These 203 feeders represent the list of potential distribution upgrades that were deferred by non-targeted DERs. However, 185 of those feeders are only overloaded by less than a MW, so presumably, many of these grid needs would have been addressed through load transfers and therefore would not have presented a deferral opportunity. Furthermore, only two feeders on the system had deficiencies that were greater than 2 MW that was reduced to the extent that there was no capacity overload in the actual forecast.

The scale of these impacts is in line with the scale of the distribution overloads and planned distribution upgrades that are identified in the PG&E 2018 DDOR:

Table 9. Overview of Results from PG&E Preliminary Analysis

	Distribution Facility Rating (MW)	Overloads and planned upgrades in GNA: Specified Deferrals		Overloads by non-targeted DERs embedded in counterfactual forecast:* Unspecified Deferrals	
		# of Feeders	2022 MW Deficiency	# of Feeders	2022 MW Deficiency
Total Feeders	30,874	2,828	-	2,828	-
Overloaded Feeders in 2022	2,328	183	219	203	91
No Cost Transfers	1,799	147	144	144	70
Planned Investment	528	39	75	43	21
Candidate Deferral	394	26	26	--	--

**Values calculated in Table 8*

In other words, the counterfactual analysis does in fact increase the forecast of MW deficiencies in 2022. However, DERS caused only 21 MW of deferred distribution capacity, which is only 1.2% of the total 1,700 MW DER growth that is forecasted to occur during this time period (assuming the proportion of deficiencies that result in planned upgrades is similar for DERs embedded in the DER forecast as it is for the GNA). This relatively small impact is because most circuits are not close to being overloaded, and system-wide load growth is flat.

Although a power flow analysis is necessary to determine which circuits need distribution upgrades vs. being addressed with load transfers, the results of that study would likely result in a relatively small change in the total capacity of distribution system upgrades that were deferred through DERs—some circuits will realize higher demand than forecast, and other circuits will realize lower than expected demand, but in the absence of additional information, it is reasonable to assume as a first approximation that the discrepancy between over and under-forecasted capacity will balance each other out. While the simplified approach described above may significantly overestimate the deferred distribution, the scale of potential deferral remains low. This preliminary analysis suggests that the unspecified avoided costs of distribution attributable to non-targeted DERs are relatively small. A comprehensive analysis of the three IOUs will require a complete dataset of the IOUs' distribution system loading capacity in the submission of their 2019 GNA.

However, these results may change if building and transportation electrification creates substantial load growth that has not yet been accounted for in the IEPR forecast. In coming years, the CEC will have more information regarding the rates of electrification, with which the

Energy Division Recommendation on Unspecified Avoided Transmission Costs

At the December 20, 2018 workshop, Energy Division staff reviewed Parties' proposals for an avoided transmission cost, which were presented in the LNBA Long Term Refinements Working Group Report. There are several additional issues to those identified for distribution which add to the complexity of an avoided transmission cost value, particularly with regards to a locationally-specific transmission deferral value. These include, but are not limited to:

- **Generation and Transmission can serve as substitutes.** Transmission lines can replace generation capacity in local capacity areas and vice versa, so the avoided cost of transmission is highly specific to the individual transmission project, and the options for local capacity generation. Additionally, the value of local Resource Adequacy (RA) is subject to many additional factors, since energy is procured though many different energy markets so determining the avoided cost of transmission overlaps with avoided cost of generation.
- **Transmission capacity constraints are not as clearly defined as distribution capacity constraints.** Transmission needs the available capacity to meet “N-1 contingency”, the condition in which the transmission system can meet the load under the condition that the nearest transmission or generation asset is offline. This need varies by location and depends on the shifting loading capacities of other neighboring circuits. Thus, there is not a constant, stable capacity value that is defined as a capacity overload for transmission as there is for distribution.
- **Transmission needs are planned for a 50-year asset.** Transmission planning is less about identifying and addressing a discrete capacity need in the near term, as distribution planning does, as it is about addressing long term population growth and generation supply.

Based on an examination of relative impact of DERs on the demand forecast at the busbar level, staff estimates that as with the distribution capacity deferred by DERs, the transmission capacity that is deferrable by DERs is likely a small fraction of the total marginal cost of transmission. For this reason, staff finds that the avoided cost of transmission is likely be to be substantially less than the marginal cost of transmission. One option for inclusion in the ACC may be to apply a derate factor to the marginal cost of transmission to reflect factors such as those discussed above.

As for the calculation of the marginal cost of transmission, PG&E has provided such in its recent GRC Phase II filings. Their transmission marginal cost is based on the capacity-driven projects in their transmission plan and is estimated using a method similar to that used for their marginal costs for distribution. Staff believes that SCE and SDG&E should be able to execute similar calculations based on their respective transmission plans without excessive burden. To be clear, staff is recommending calculation of marginal costs for peak demand changes to the utility base forecasts. Staff is not suggesting at this time that the utilities create new transmission plans and investment forecasts based on alternate load forecast, as was discussed by some parties in the LNBA Working Group.

Staff seeks further input from parties to either explore this approach, further refine parties’ current proposals, or examine other potential data sources upon which to base avoided cost of transmission, such as locational marginal pricing.

5. Energy Division’s Proposed Approach on Specified Transmission and Distribution Deferral Value

While the scope of this paper deals explicitly with methodological approaches to calculate unspecified T&D deferral vales, Energy Division believes it is important to also point out preferred approaches to apply specified deferral values in other venues. PU Code Section 1002.3 states that the commission shall consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation, and other demand reduction resources.

The Commission is addressing this requirement by expanding this DIDF process to include transmission projects that are under CPUC jurisdiction, as was required in the May 7, 2019 *Administrative Law Judge's Ruling Modifying the DIDF Process*. For establishing and monetizing specified avoided distribution costs, Energy Division propose to apply the values resulting from the annual DIDF process, and through potential new DER tariffs under consideration in IDER, not the avoided cost calculator. The DIDF process is currently in its 1st 2018 cycle with new solicitations underway. Based on a review of stakeholder input on how to further refine and improve the DIDF process and framework, the Commission issued a Ruling to implement certain improvements to the DIDF process and framework. One such change is starting in 2019, the IOUs will include transmission projects that are subject to CPUC jurisdiction in their annual GNA and DDOR filings for consideration as possible deferral opportunities. The Commission will continue to implement, refine and improve the DIDF as well as incorporate lessons learned in the IDER pilots, and is currently evaluating proposals for DER tariffs in the IDER proceeding, which are based on the specified distribution deferral opportunities identified in the GNA and DDOR.

For specified avoided transmission, the California Independent System Operator (CAISO) have expressed their commitment to identify and consider non-wire alternatives across the entire transmission and distribution system. CAISO has integrated non-wires alternatives into their Transmission Planning Process (TPP).[18] Each year, CAISO conducts its TPP to identify potential system limitations as well as opportunities for system reinforcements that improve reliability and efficiency. The TPP core product is the CAISO Transmission Plan, which provides an evaluation of the CAISO control grid, examines conventional grid reliability requirements and projects, summarizes key collaborative activities and provides details on key study areas and associated findings. For each planned transmission project CAISO considers non-wires alternatives and this can sometime result in solicitation of DERs as transmission alternatives. An example of this is the Oakland Clean Energy Initiative where PG&E and East Bay Community Energy are actively procuring DER solutions to replacing aging gas power plants in Oakland, CA to avoid the need to build new transmission lines to serve the Port of Oakland.

Commission staff recently incorporated consideration of non-wires alternatives into the review of a proposed new transmission projects, the SCE Application (A. 15-12-007) for a Permit to Construct Circle City Substation and Mira Loma-Jefferson Sub-transmission Line Project. Certain transmission projects authorized as needed through the TPP trigger a California Environmental Quality Act (CEQA) review which involves an application to the CPUC. The CEQA process provides for the study of alternatives to the infrastructure project under study if the alternative can lessen or eliminate a significant environmental impact. In the cases above the CPUC is considering battery storage alternatives to building new transmission assets.

To date the number of times DERs are procured as substitutes for planned transmission projects is very limited, but recognition of the potential is increasing. Several jurisdictional, planning and analytic issues must be addressed if there is to be more use of DERs as alternatives to planned transmission projects.

[18] The CAISO 2019-2020 Transmission Planning Process Final Study Plan issued on April 3, 2019 states "If reliability concerns are identified in the initial assessment, additional rounds of assessments will be performed using potentially available demand response and energy storage to determine whether these resources are a potential solution. If these preferred resources are identified as a potential mitigation, a second step - a preferred resource analysis may then be performed, if considered necessary given the mix of resources in the particular area, to account for the specific characteristic of each resource including use or energy limitation in the case of demand response and energy storage." Pg. 24

6. Recommendations

In consideration of the large body of information previously provided by parties both on the record of the DRP proceeding as well as informally, staff provides the following recommendations regarding the locational granularity of transmission and distribution avoided costs for the various potential use cases that were identified in Section 2. To provide context for these recommendations, we first review the current or proposed methods for calculating each type of deferral value and category of use case, and the level of uncertainty in each. Since the procurement use cases involves monetizing the transmission and distribution deferral value, the threshold for reliability in the results needs to be higher than for the planning use case.

Assessment of Uncertainty in Deferral Values as Applied to Types of Use Cases

1. **Specified Distribution Deferral Value**

   - **Planning Use Cases:** The specified distribution deferral value is currently developed and applied in DIDF process through the LNBA, and the level of uncertainty for the circuit level values should be acceptable for all planning use cases, including IRP.
   - **Procurement Use Cases:** The specified deferral values are currently quantified at the circuit level of granularity in the DIDF procurement process for the DIDF procurement use case. This calculation has a reasonably high degree of certainty, as they are continually updated in the annual distribution planning process, and the IOUs will bring the locational granularity to the sub-circuit/nodal level in 2019. Other procurement use cases, e.g., DER tariffs, may use these values, as long as they are for separate locations from projects that are included in the DIDF solicitations.

2. **Unspecified Distribution Deferral Value**
   Section 4 on the limitations of the staffs' preliminary analysis explained how the determination of which circuits may be addressed using no-cost load transfers and which would require distribution system upgrades is highly uncertain. Reducing this uncertainty would require a powerflow analysis using counterfactual load data. Staff does not find that the effort required is justified by the size the of the potential distribution deferral. Furthermore, there would still be a significant amount of uncertainty in a powerflow analysis on a counterfactual forecast, since minor changes in load growth would result in the powerflow analysis being inaccurate.

   - **Planning Use Cases:** It may be possible to derive an unspecified distribution deferral value at the substation/feeder bank level that improves the certainty of these values. ED staff has not attempted to do this analysis, as it may require consultant technical support to develop and incorporate the calculations into the LNBA and IRP capacity expansion models. Given the small scale of potential distribution deferrals that can be anticipated to result from this analysis, ED staff would suggest that the effort to disaggregate the distribution deferral value in these models is not justified but seeks input from the parties on this position. At this time, ED staff recommends that the granularity of unspecified distribution deferral value be applied at the system level.

- **Procurement Use Cases:** As with the planning use case, an aggregation of deferral value may be useful at the substation/feeder bank if highly loaded feeders are clustered together. As such, a locational tariff may be useful to defer distribution in areas where there are limited opportunities to transfer load and reconfigure the grid, and a GNA-based analysis may serve this use case. However, given the potential for shifting of loads between feeders, staff does not find a locationally granular breakout of distribution deferral value to be well suited to the avoided cost calculator. The avoided cost calculator values are updated annually at best, and must be used for many different use cases, including to establish the energy efficiency portfolio budgets. The uncertainty of the shifting locations of distribution needs does not align well with the use cases for the avoided cost model, like EE portfolio budget setting. Therefore, the staff recommends that granularity of unspecified distribution deferral value be applied to the avoided cost calculator at the utility territory level as a uniform value.

3. **Specified Transmission Deferral Value**
   Calculating the value of DERs to meet specified transmission deferral needs should be addressed in the Transmission Planning Process if they are under CAISO jurisdiction. The CPUC DIDF process has recently expanded to cover transmission upgrades that are CPUC jurisdictional. Both processes are relatively new and can benefit from learning and improvement.

4. **Unspecified Transmission Deferral Value**
   The amount of uncertainty associated with the location of unspecified transmission value is extremely high, as discussed in Section 4. It may be possible to include a locational granularity that is below the system level, as SCE proposes in their workshop presentation, dividing the utility territory into import, export and neutral zones. Staff does not find that the amount of value that may be attributed to these zones would justify adding the complexity to the avoided cost calculator, LNBA or IRP capacity expansion models.

Recommended Methodology for Transmission and Distribution Deferral Value

Staff's recommendations for estimating distribution deferral value mirrors, at a high level, the approaches of PG&E and NY as presented at the December 2018 workshop (see Appendix B). Specifically, staff proposes to divide distribution deferral value into both locationally granular and non-granular components based on whether the deferral value is specified or unspecified. For the locationally granular component, staff proposes that values associated with the DIDF process be used, consistent with PG&E's proposal. For the non-locationally granular component, staff proposed to use data derived from DIDF, but modified to reflect a quasi-counterfactual[19] future in which forecasted DERs are not installed.

Table 5 below summarizes staff's recommendations for methodology and the level of granularity for each type of deferral value, along with the rationale for each.

[19] "Quasi-counterfactual" reflects the fact that the deficiencies are estimated not based on power flow analysis but based on a simplified extrapolation of original power flow analyses used to generate the GNA.

Table 5. Staff Recommendations for Transmission and Distribution Deferral Value Methodologies and Locational Granularity

Value	Existing process to calculate value	Recommended Methodology	Recommended Granularity of Final Value	Rationale for Recommended Methodology
Specified distribution deferral value	DIDF	Continue DIDF/GNA/DDOR	Location-specific as identified in DIDF	Consistent with existing distribution planning methods that underly traditional investments.
Unspecified distribution deferral value	Marginal cost from GRC applied through PCAF method and annual updates to Avoided Cost Calculator	Energy Division GNA-based counterfactual analysis	Climate Zone or Utility territory	The GNA data can provide more accurate analysis of the direct impact of DERs on the circuit level, which in aggregate is relatively reliable, but which specific feeder upgrades will be deferred is more uncertain
Specified transmission deferral value	CAISO TPP identifies the transmission needs but does not determine the costs. CPUC CEQA Applications also consider NWAs as environmental alternatives.	Continue to use the CAISO and CPUC methods. CPUC DIDF to begin to include CPUC jurisdictional transmission in 2019	Location-specific as determined by each project	Consistent with existing TPP process, existing DIDF process, and existing CEQA process.
Unspecified transmission deferral value	Annual CPUC updates to Avoided Cost Calculator	None at this time	Utility territory	More granular values cannot be calculated with acceptable certainty.

Recommendations Regarding Implementation of Unspecified Distribution Deferral Value in ACC

To implement the use case of the GNA and DDOR data to identify utility-wide unspecified distribution deferral value, Commission staff recommend that the IOUs be required to take the following steps:

1. Analysis for distribution deferral value should be conducted using the 2019 GNA, to include facilities that were not included in the 2018 GNA
2. A counterfactual hourly load forecast should be developed by adding the hourly load impact of the DER forecasts included in each utility's GNA. This process should account for the shapes of the underlying DERs.
3. Demand reduction from non-targeted and DER growth driven by codes and standards should be kept in the counterfactual forecast
4. Deficiencies across the utility's distribution system should be assessed assuming the new load forecast through simplified extrapolation exercise, rather than a detailed power flow analysis.

5. Deficiencies that can be addressed at low or no cost, without the use of significant new infrastructure investments should be removed.
6. Deficiencies that cannot be deferred using DERs should be removed.
7. The cost of any remaining deferrable infrastructure investments should be summed across the utility territory to represent the aggregate unspecified distribution deferral value.

The resulting utility-wide number would then be available for incorporation into the avoided cost calculator, or other tools, for application in any use case. The specified and unspecified distribution deferral values would be additive.

(END OF ATTACHMENT A)