STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

IR 15-296

Electric Distribution Utilities
Investigation into Grid Modernization

COMMISSION STAFF'S RESPONSE TO EVERSOURCE MOTION FOR RECONSIDERATION AND/OR CLARIFICATION OF ORDER NO. 26,358

On June 22, 2020, Public Service Company of New Hampshire d/b/a Eversource Energy ("Eversource") filed a Motion for Reconsideration and/or Clarification of Order No. 26,358 (Motion). Staff of the New Hampshire Public Utilities Commission (Staff) hereby responds to this Motion and states as follows:

1. Under RSA 541:3, the Commission may grant rehearing when a party states good reason for such relief. A successful motion for rehearing does not merely reassert prior arguments and request a different outcome. *Public Service Company of New Hampshire*, Order No. 25,239 at 8 (June 23, 2011). RSA 541:4 requires a motion for rehearing "shall set forth fully every ground upon which it is claimed that the decision or order complained of is unlawful or unreasonable." While Staff takes no position on whether Order No. is unlawful or unreasonable, we take this opportunity to provide further information in response to some of the points of contention identified in the Motion.
2. Eversource's primary concern with the Order relates to the Order's treatment of so-called "business-as-usual" investments, which would be prospectively reviewed by a Grid Modernization Stakeholder Group (GMSG) and a related Independent Professional Engineering firm prior to LCIRP filings. In addition to various legal arguments, Eversource asserts certain policy-related claims that applying the GMSG construct to

"business-as-usual" investments. Motion at 18-22. Many of these concerns appear anchored in Eversource's chosen interpretation of the role of the GMSG described in the order, but some relate to the Company's purported lack of planning for individual projects and distribution system needs more than a year or two in the future.

3. Although the Company prepares a five-year budget forecast, it notes that "projections beyond Year 2 are estimated on a general basis, and not tied to specific projects that will be executed in the exact year planned," and suggests that planned expenditures are "grouped in broad categories (with some likely candidates to evaluate) to provide the five-year outlook and then individual projects are evaluated against each other to determine the best use of limited funds as the 2-year time frame approaches." Motion at 22. In essence, the Company knows which projects it is likely to build several years ahead of time, but its commitment to build a given project in a given year does not occur until approximately 24 months prior to the need for that project to be in service.

4. Not *fully* committing to a project until less than 24 months prior to its in-service date offers the benefit of allowing the Company to use the latest facts and circumstances on the grid to determine whether a project it had been planning is still the best use of funds. However, in practice, the Company's two year demarcation point for deciding between the projects it is actually planning v. "likely candidates" has served to limit prospective project review and meaningful opportunities for consideration of least-cost alternatives that may exist. For example, in response to a Commission directive to identify planned future investments that might be considered for non-wire solutions in Order No. 26,029, the Company identified only projects planned to be in-service within 24 months, limiting their eligibility for any meaningful review of alternatives due to the limited timespan for

consideration. Likewise, the Company is requesting several years' worth of step adjustments after the historic test year in its ongoing rate case based on an illustrative revenue requirement, but has declined to provide Staff with information regarding exactly which investments it is planning. Attachment 1 provides Eversource's detailed explanation of this approach to planning as explained via discovery in its ongoing rate case.

5. Regardless of the Eversource's motivation for differentiating between planned v. candidate investments, it appears that the Company maintains a prioritized list of investments it will likely make beyond the 24 month planning horizon. The Company has consistently provided documentation in discovery, such as area planning studies and solution selection forms, that show it has directly studied many of the projects in plans to undertake beyond the two year demarcation point. An example of such a document, relating to the Company's Emerald Street Substation, which was identified as a need in 2012 and has a planned in-service date of 12/31/21, is attached to this motion at Attachment 2.

6. Eversource also cites a lack of evidence that "a process or group like the GMSG being implemented by a public utility commission anywhere in the country with a planning statute similar to New Hampshire's to review core utility distribution investments." Motion at 23. Several states have adopted a similar stakeholder-involved process for reviewing planned investments for least-cost alternatives, including California and Hawaii. *Report of Independent Professional Engineer on PG&E 2018 DDOR/DPAG Report*, provided as Attachment 3; See also, *Presentation by Marc Assano of the Hawaiian Electric Company at the 2019 Smart Electric Power Grid Evolution Summit Regarding HECO's Integrated Grid Planning Process*, provided as Attachment 4.

7. In summary, while Staff takes no position on whether Order No. 26,358 is unlawful or unreasonable as Eversource contends, we take this opportunity to provide further information in response to some of the points of contention identified in the Motion as a means of further illuminating the record regarding newly raised arguments.

WHEREFORE, for the reasons set forth herein, Staff respectfully requests that the Commission:

1. Accept the information provided in this Staff response in support of the record in this proceeding; and
2. Grant such further relief as is just, equitable, and appropriate.

Respectfully submitted,

Staff of the Public Utilities Commission

By its Attorney,

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I hereby certify that, on June 29, 2020, a copy of this Response has been hand delivered to the Commission and has been sent electronically to the Service List in this matter.

Brian D. Buckley

Brian D. Buckley

-Attachment 1-

DE 19-057, Eversource Response to Staff 13-009

Detailing Capital Budgeting/Planning Approach

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/10/2019 | **Date of Response: 10/24/2019**
Request No. STAFF 13-009 | **Page 1 of 1**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Troy Dixon, Douglas P. Horton

Request:
Reference Company response to OCA 6-45, in which the Company responds to a request for its base capital plan, which contemplates $135 million in investments annually through 2023, by directing the reader to Bates SFR-003970, which contains only two years of forecasted capital investments broken down into only four categories of distribution base capital investments. Please provide the detailed base capital plan used by the Company to determine the $135 million in investments it seeks within the step adjustments through 2023.

Response:
The Company's capital planning process begins with a high-level, long-range (5 year) capital expenditure and capital addition forecast by major category of investment developed in the spring timeframe of a given year. This 5 year forecast is also referred to as the strategic plan. Toward the end of the year, a detailed one-year capital expenditures plan at the specific project level is developed for the coming year and forms the basis of the Company's capital budget. This capital budget includes capital additions and cost of removal.

In this proceeding the Company has calculated illustrative step adjustments based on the capital expenditure forecast currently available which, for the out years is still at the major category level and is not yet developed at the specific project level detail that accompanies the one year plan. However, please note that the calculations included in this proceeding are for illustrative purposes. The Company is not at this time requesting that the PUC authorize the precise step adjustment in future years that has been calculated in this case. Here, the Company is requesting to implement step adjustments on a going forward basis that will be calculated based on actual plant placed in service through the end of the year prior to the year the step adjustment goes into rates.

The illustrative step adjustments provided in this rate case are estimated based on the high-level, long range capital addition forecast, which is produced by category of investment and not at a specific project level. However, a detailed plan for capital expenditures at the project level is available for 2019 and is provided in the Company's annual construction budget filing which was provided in SFR-001756 and Attachment OCA 1-009 F.

The base capital plan referenced in the Purington and Lajoie testimony is a subset of the total PSNH capital expenditures budget. OCA 6-045 asked for the 2019 base capital plan as referenced in the Purington and Lajoie testimony. Further detail about this base capital plan for 2019-2023 is provided in the strategic plan as provided in Attachment OCA 4-001, pages 83-107.

-Attachment 2-

DE 19-139, 2019 LCIRP Attachment P

Emerald Substation Solution Selection Form

REDACTED

EVERSOURCE

Solution Selection Form

Date Prepared: January 28, 2019	**Project Title:** Rebuild Emerald Street SS
Company/ies: Eversource NH	**Project ID Number:** A14W01 (D) **&** T1347A (T)
Organization: NH Operations	**Class(es) of Plant:** Distribution & Transmission SS
Project Initiator: Thelma Brown	**Project Category:** Peak Loading/Reliability-Obsolete Eqmt
Project Manager: [redacted]	**Project Type:** Specific
Project Sponsor: [redacted]	**Project Purpose:** Address Keene area load and replace obsolete equipment at Emerald Street SS
Estimated in service date: 12/31/21	**If Transmission Project: PTF?** Yes

The information required (need, objectives, scope of preferred solution, cost estimate(s), and alternatives analysis) can be supplemented with attachments (i.e. MS Word, MS PowerPoint, MS Excel, PDF files). Attachments should be submitted as separate files and not embedded within this form. Previously approved Initial Funding Request forms or other approved authorizations should be included with the submission of this form as a separate attachment.

Project Need Statement

In 2012 an area study was performed to determine how to best address the area loading and retirement of equipment at the Emerald Street SS. The study recommended two substation projects to replace the existing equipment currently concentrated at the Emerald Street SS in Keene: 1) a new 115-12.47kV substation in the north section of Keene; and 2) a new/rebuilt 115-12.47kV substation on Emerald Street, at the site of the existing substation. This approach places sources closer to the load, addresses aging and over-duty equipment, and provides two separate electrical sources to the area.

In November 2016 the North Keene SS was put in-service. The next phase for the Keene area was rebuild of the existing Emerald Street SS. Full funding of Transmission at $1,644k (approved 6/14/18) and Distribution at $11,011k (approved 12/27/17) was approved for these projects.

Since the approval of these projects the Distribution portion of the work has not changed but additional costs require a request for additional funding. Distribution construction is underway and the SDC is not being requested to review this work.

The transmission scope of work has increased as a result of SCLL review by the Electric System Control Center (ESCC). Three new 115kV circuit breakers are requested for the construction phasing of the project. The options being presented to the SDC have to do with alternatives for transmission construction and funding.

Project Objectives

Transmission - To support the Distribution project requirements. The Transmission scope includes updating transmission equipment to limit exposure of outages to the customers, and layout the system to be more easily maintained in the future.

Distribution - To address loading and replacement of obsolete equipment on the Distribution System (see attached original PAF).

Alternatives Considered with Cost Estimates:

- **Alternative 1:**

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This alternative is to continue with the Distribution as planned based on the approved PAF dated 9/25/17 and the approved Transmission scope of work outlined in the PAF dated 4/25/18. Both of these documents are attached. The proposed one-line is attached.

The positive aspects of this alternative are that it addresses the remaining Protection and Control obsolete equipment replacement. This is also the least cost Transmission Alternative.

It does not provide a tie between 115kV lines A152 and D108. Therefore, during Bus 2 outages required for construction, there will be customers at risk for a SCLL. System Planning reviewed this construction scenario:

When System Planning studies scheduled outages in the short-term, cascading load (offloading an affected area to increase local system capacity for restoration efforts) is acceptable as the review is of an N-1-1 scenario. Current system planning criteria for N-1 distribution studies does not allow cascading load transfers and directs system improvements based on system restrictions found. Restoration switching for contingencies during an Emerald Street Substation 115 kV Bus 2 outage was reviewed with and without cascading switching. When a planned outage occurs between Greggs and Emerald Street, the ESCC (Electric System Control Center) usually institutes some pre-contingent switching to reduce customer exposure. This review looks at the system as-is without any pre-contingent switching.

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[redacted]

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[redacted]

EVERSOURCE

Estimated cost of Alternative 1:
Distribution = $15,800k
Transmission = $1,673k

- **Alternative 2**
  This alternative is to continue with the Distribution as planned based on the approved PAF dated 9/25/17. The transmission work will be expanded to include a 115kV circuit breaker tie between the A152 and D108 lines. This circuit breaker will be used during construction. After construction it will be operated normally open and used only for future breaker maintenance. The proposed one-line is attached.

  The positive aspect of this alternative is that it addresses the SCLL issues identified in Alternative 1 to limit customer exposure during Bus 2 construction outages. It also allows for using the breaker during future breaker maintenance, removing the customer exposure to SCLL conditions.

  The challenge to this alternative is that it increases the transmission investment and exposes customers to SCLL conditions during the construction and commissioning of the new 115kV breaker. Alternative 2 costs more than Alternative 1 and will be a local transmission cost.

  Estimated cost of Alternative 2:
  Distribution = $15,800k
  Transmission = $3,246k

- **Alternative 3**
  This alternative is to continue with the Distribution as planned based on the approved PAF dated 9/25/17. The 115kV circuit breaker tie between the A152 and D108 lines from Alternative 2 is included. Two additional circuit breakers are added in the 115kV bus to replace existing switches. The proposed one-line is attached.

  The addition of 115kV bus tie breakers at the Keene substation improves customer reliability and ease of maintenance. For any single bus contingency, all customers can be restored via SCADA switching within 5 minutes. Without bus tie breakers, the single bus SCLL strands approximately 2500 customers due to distribution limitations. Ease of maintenance is increased when a bus section is required OOS. Without bus tie breakers, removing a section of bus from service requires offloading multiple transformers.

  The challenge to this alternative is that it increases the transmission investment and exposes customers to SCLL conditions during the construction and commissioning of the new 115kV breakers. Alternative 2 costs more than Alternative 1 and will be a local transmission cost. There is some concern by P&C regarding the use of the breakers and impact on bus differential scheme relays.

  Estimated cost of Alternative 3:
  Distribution = $15,800k
  Transmission = $4M+ ($3,246k cost from Alt. 2 plus two additional 115-kV breakers)

- **Alternative 4**
  This alternative is to continue with the Distribution as planned based on the approved PAF dated 9/25/17. The three new 115kV circuit breakers in Alternative 3 are included. Instead of being controlled only by SCADA they will be used with three bus differential schemes allowing for a limited exposure to customers for a bus fault.

  The additional benefit of Alternative 4 over Alternative 3 is that the customer reliability is improved by converting a single SCLL of 8560 customers to three separate SCLLs of 1215, 2125, and 5219 customers.

  The challenge to this Alternative is that it has an adverse impact on the system.

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Estimated cost of Alternative 4:
Distribution = Not applicable
Transmission = Not applicable

Because Alternative 4 creates an adverse system impact this alternative was discounted and a conceptual cost estimate was not created.

- **Alternative 5**
  This alternative is to continue with the Distribution as planned based on the approved PAF dated 9/25/17. The transmission will be rebuilt to a 115kV breaker and a half configuration.

  This transmission configuration has many advantages over the existing 115kV straight bus configuration.

  The challenge to this Alternative is that there is no land to expand the substation in this location. In order to complete the distribution project the 115kV straight bus design will need to remain.

  Estimated cost of Alternative 5:
  Transmission and Distribution = $29,380k (2012 dollars)
  Alternative 5 was estimated in TPS# 14-165-NH

  No non-wires alternatives were analyzed for this project. The project's primary objective is to replace obsolete systems. At the transmission level this alternative is a one-for-one replacement and includes a new secondary bus differential scheme.

Project Scope (Preferred Solution)

Alternative 3 is the preferred solution. Attached is the scope document.

This alternative is chosen because it provides the most flexibility and is preferred by Station Operations and ESCC.

Cost Estimate Backup Details

Provide backup details of conceptual grade cost estimates (-25%/+50%) for all appropriate alternatives (at least the preferred solution and leading alternative).

Attachments (maps, images, one-line diagrams, MS PowerPoint presentations, MS Excel cost estimate files, etc.)

-Attachment 3-

Independent Professional Engineer Report to

California Public Utilities Commission

Regarding Distribution Deferral Opportunities and the Work of the Distribution Planning Advisory Group

REPORT

Independent Professional Engineer PG&E 2018 DDOR/DPAG Report

Submitted to California Public Utilities Commission and PG&E

November 27, 2018

Statement of Confidentiality

As directed by the California Public Utilities Commission (CPUC) Decision 18-02-004, a Distribution Planning Advisory Group (DPAG) was formed and made up of both non-market participants and market participants. The CPUC decision also provides for certain market sensitive information that is discussed as part of the DPAG process to be provided only to the non-market Participants of the DPAG. This report, however, does not contain any information that PG&E considers as confidential and thus this report can be provided to any member of the public.

Contents

1 Introduction and Background

Summary of CPUC Decision (D.) 18-02-004

The paragraphs that follow summarize the parts of the CPUC decisions that directly impact this report.

The CPUC directed that the IOUs shall file, in reports pursuant to their Decision, a Grid Needs Assessment (GNA) by June 1 of each year, and a Distribution Deferral Opportunity Report (DDOR) by September 1 of each year. The GNA and DDOR shall provide a characterization of circuits according to the data types and attributes described in their decision. The CPUC decision directs the IOUs to file a Tier 2 advice letter 60 days following the issuance date of this Decision proposing DRP data redaction criteria that work to ensure the physical and cyber security of the electric system and reflect the customer privacy provisions established in Decision (D.) 14-05-016.

The Commission adopted Cost-Effectiveness, Forecast Certainty, and Market Assessment metrics to characterize and help prioritize projects on the candidate deferral shortlist. The Commission did not prescribe specific methodologies by which these metrics should be implemented in the initial roll-out of the DIDF, and instead direct the IOUs to apply these metrics according to their own approaches. The CPUC's overarching goal of the DIDF is that any candidate deferral project that can be cost-effectively deferred through DERs should be deferred.

The Commission ordered the actual cost of distribution system upgrades to be considered public information as part of the ongoing DIDF, and in associated DRP tools such as the Locational Net Benefits Analysis (LNBA).

The Commission established the DPAG to consist of IOUs, Commission technical staff, an Independent Professional Engineer (IPE) technical consultant, non-market participants, and DER market providers.

The Commission ordered that the IOUs, in their annual DDOR filing, shall include a proposed DPAG work plan and agenda for the DPAG process. Parties could then provide comments on the proposed agenda within one week, followed by a letter from the Director of the Commission's Energy Division establishing the final agenda within two weeks.

The IOUs' proposed DPAG agendas shall, at a minimum, encompass a review of: 1) planning assumptions and grid needs reported in the GNA; 2) planned investments and candidate deferral opportunities reported in the DDOR; and 3) candidate deferral prioritization. Importantly, as part of the discussion on candidate deferral opportunities, the IOUs shall present the underlying technical and operational requirements that a given DER alternative must provide in order to successfully meet the underlying grid need.

The Commission ordered the IOUs to file a Tier 2 Advice Letter at the conclusion of the DPAG process, by December 1 each year, recommending the distribution deferral projects that should go immediately out for solicitation via the Competitive Solicitation Framework (CSF) Request for Offer (RFO). These advice letters to include preliminary contingency plans, developed to the guidance provided, as well as the IPE's DPAG Report, as attachments. The IPE's DPAG Report will put forth his or her evaluation of the DPAG review process, plus any stakeholder feedback regarding candidate projects that the IOUs did not propose for solicitation. The Commission may then rule on these non-consensus projects in a separate resolution from that which disposes of consensus projects.

To meet these objectives, metrics are required to characterize whether: 1) a deferral project would likely result in net ratepayer benefits; 2) the forecast grid need underlying a potentially deferrable investment is likely to materialize; and 3) the potential DER marketplace within the electrical footprint provides an adequate market opportunity to host DER solutions. As such, the CPUC adopted Cost-Effectiveness, Forecast Certainty, and Market Assessment metrics to characterize and help prioritize projects on the candidate deferral shortlist.

The IPE should be primarily concerned with providing neutral expertise on distribution planning activities and the selection of candidate deferral opportunities

Independent Professional Engineer

California Public Utilities Commission (Commission) Decision (D.) 18-02-004 issued February 15, 2018, directs Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) to enter into a contract with an Independent Professional Engineer (IPE). The primary role of the IPE is to participate in a newly formed interim stakeholder group called the Distribution Planning Advisory Group (DPAG) established for the purposes of reviewing the material presented to the DPAG and to support the DPAG in its review of projects proposed by the Utilities for deferral through the procurement of DERs and the review of projects that were not proposed for DER deferral.

The IPE will also be a participant on the Procurement Review Group (PRG) of each Utility for the purposes of the PRGs advisory review of the DER procurement process to determine if the planned infrastructure investment can be deferred.

Through a contract with Nexant, Inc., PG&E engaged Mr. Barney Speckman[1], PE, to serve as the advisory engineer (referred to as the Independent Professional Engineer (IPE)) for the GNA/DDOR process that will lead up to a PG&E filing a Tier 2 Advice letter on December 1, 2018. The statement of work included in the contract for the IPE includes the requirement to prepare a

[1] Consistent with the CPUC decision, the contract with Nexant Inc. the firm where Mr. Speckman is employed provides for other individuals within Nexant to assist Mr. Speckman to perform the work in the IPE contract provided that these other individuals are also bound by the same confidentiality and conflict of interest requirements that Mr. Speckman is required to meet.

report on the planning process and the GNA/DDOR project prioritization process used by the Utilities. To facilitate the support to be provided to the DPAG participants mentioned in the CPUC decision and to provide feedback to the Utilities, each Utility sent out a questionnaire to the DPAG participants requesting feedback on the projects that were proposed by the Utility for potential deferral through DER procurement in this year's procurement cycle and those projects that were not proposed. This report which meets the requirements included in the CPUC decision was provided to PG&E in sufficient time to be included in their December 1, 2018 Advice Letter.

1.1 DPAG Membership and Information Disclosure

As provided for in the CPUC Decision 18-02-004, the DPAG was made up of both non-market participants and market participants. The CPUC decision establishes certain data that should be shared with all DPAG participants and also provides for information that PG&E believes is market sensitive that is discussed as part of the DPAG process to be provided only to the non-market Participants of the DPAG. This report does not contain any information that PG&E considers as confidential and thus this report can be provided to any member of the public.

1.2 Services Considered within the DDOR Framework

The CPUC, in a previous decision, approved the four services proposed by the Competitive Solicitation Framework Working Group (CSFWG) and directed the utilities to consider these services in the GNA/DDOR process. The four services as described in the decision are listed below in an excerpt from the decision:

"The following definitions for the key distribution services that distributed energy resources can provide are adopted for the Competitive Solicitation Framework:

1. Distribution Capacity services are load-modifying or supply services that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure;

2. Voltage Support services are substation and/or feeder level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems;

3. Reliability (back-tie) services are load-modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations; and

4. Resiliency (micro-grid) services are load-modifying or supply services capable of improving local distribution reliability and/or resiliency. This service provides a fast

reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations."

1.3 Related Proceedings

Many of the topics of interest in the GNA/DDOR process are also the subject of discussion in other CPUC proceedings. This includes, for example, the approach and method of load and DER forecasting at the circuit level which is being discussed at the Growth Scenario Working Group and issues related to what is referred to as "the double counting/double payment issue". The focus of this report is to look at the DDOR/GNA process used by the Utilities as described in meetings with the DPAG and materials provided to the DPAG recognizing that some of the issues touched upon are also being discussed in other proceedings.

1.4 Approach to Information Collection

The information reflected in this report was obtained through a number of methods including:

- Written data requests sent to PG&E regarding their planning process that lead to the needs identified in their GNA Report and the projects included in their DDOR Report. Responses from PG&E were made during follow up conference calls, in writing and in some cases face-to-face meetings.
- Review, comment, and follow-up question sessions with PG&E during which PG&E reviewed the material that they were going to present either jointly or individually to the DPAG. This session occurred a few days before the DPAG meeting and consisted of presentation by the utilities or the provision of materials followed by questions by the IPE.
- A review of publically available materials referred to in the discussions with PG&E or materials previously filed with the CPUC by a utility.

1.5 Report Contents

The remainder of this report includes the following sections:

- Review of GNA Report (Section 2) which briefly discusses the contents of the PG&E GNA Report
- Review of DDOR Report (Section 3) which briefly discusses the contents of the PG&E DDOR Report
- Review of DPAG Presentations/Proposals (Section 4) which reviews the materials provided and proposals made by PG&E at their DPAG meetings and calls
- Review of Metrics and Prioritization (Section 5) which reviews the use of additional metrics to support the prioritization of candidate projects based upon cost-effectiveness

- DPAG Comments Received (Section 6) which includes responses to comments/questions received from DPAG members.
- Discuss of Other Issues (Section 7) which covers additional issues that came up during the DPAG meetings
- Observations/Conclusions/Recommendations (Section 8) which includes feedback from the IPE on selected items covered in Sections 2 through 7.
- Comments Received from the DPAG Members (Appendix A)

2 Review of GNA Report

The GNA Report submitted by PG&E is summarized below.

2.1 Summary of PG&E's 2018 GNA Report

The following sections describe the study methodology and assumptions used to forecast and identify distribution grid needs in PG&E's 2018 GNA submittal.

PG&E's Distribution Resources Planning Horizon

To align with the circuit-level planning assumption requirements provided in D.18-02-004, PG&E used a 10-year forecast as the study horizon for identifying grid needs. For the 2018 GNA submittal, PG&E provided the assessment for the 10-year planning horizon for the years 2018 through 2022.

PG&E's Distribution System Load Forecast Assumptions

PG&E's load growth forecast began with the most recent approved California Energy Commission (CEC) PG&E Transmission Access Charge (TAC) area Peak and Energy Forecast: Mid Baseline growth forecast. Transmission-connected load growth and known new distribution loads were deducted from the CEC system load growth forecast. The resultant growth was distributed out by customer class (residential, industrial, commercial, and agricultural) and was then allocated to PG&E's distribution feeders using geospatial analysis. PG&E uses the LoadSEER GIS geo-spatial forecasting program, created by Integral Analytics. This program uses satellite imagery and proprietary data analytics to score each acre in PG&E's territory for the likelihood of increased load by customer class.

PG&E's Distribution System DER Growth Forecast Assumptions

Separate from load growth, PG&E incorporated DER adoption into its distribution bank and feeder forecast assumptions. This is accomplished for residential photovoltaic (PV), retail non-residential PV, energy efficiency for different customer classes, electric vehicles, and load modifying demand response. The starting point for developing these feeder level DER growth forecasts was the CEC's California Energy Demand (CED) forecast that is completed at the system-wide level. Staying consistent with the CED forecast, the system-wide incremental MW capacity by DER technology type was allocated to the feeders based on allocation methodologies specific to the DER types. Variables used to allocate incremental DER capacity geospatially include consumption by customer class, amount of generation by feeder, historical photovoltaic (PV) system adoption by zip code, the s-curve trending model, observed distributed generation (DG) penetration level, daily peak diversity factors, weather zones, and many other factors specific for each type of DER. Consistent with the Assigned Commissioner's Ruling on the adoption of Distributed Energy Resources Growth Scenarios issued August 9, 2017, PG&E's Distribution System DER Growth Assumptions utilize:

- CED Update 2016 Mid Baseline Photovoltaic Generation
- CED Update 2016 Mid Baseline Electric Vehicles
- CED Update 2016 Mid Baseline Energy Storage
- CED Update 2016 Mid Baseline Load Modifying Demand Response
- CED Update 2016 Mid Baseline-Low Additional Achievable Energy Efficiency

PG&E did not incorporate a feeder allocation methodology for energy storage since it is still under development. However, energy storage adoption was included in the system level forecast.

PG&E's Load Transfers and Switching Assumptions for 2018 GNA

PG&E's 2018 GNA submittal included the results of PG&E's electric distribution grid as a snapshot in time and does not include future planned load transfers and switching operations that will be used to balance the load between feeders and banks. Consequently, many of the grid needs identified in the GNA will be mitigated by such operations rather than a planned investment. Typically, planned load transfers and switching operations, which are utility industry common best practices, are the lowest cost alternatives that take advantage of available existing "back-tie" interconnections and capacity on adjacent distribution feeders and banks.

Grid Needs Assessment Scope

As adopted in D.18-02-004, grid needs that were reported in PG&E's June 1, 2018, GNA submittal were limited to the substation level forecast deficiencies and to some feeder level deficiencies that are associated with the four distribution services that DERs can provide as adopted in D.16-12-036. Specifically, these services are distribution capacity, voltage support, reliability (back-tie) and resiliency. For this year's GNA, identified needs were limited to substation level forecast of distribution capacity and limited reliability (back-tie) distribution grid needs for both substation transformer banks and feeders. As distribution planning tools and processes are further enhanced and refined, PG&E plans to include more components in the Distribution Resources Planning process, such as feeder-level needs downstream of the substation. PG&E's initial 2018 GNA filing identified 316 grid needs. The grid needs for the initial GNA included substation and limited feeder needs. The initial GNA identified distribution capacity and limited reliability needs. It is important to note that most of the identified grid needs will likely be mitigated via distribution switching and load transfers, with the remaining grid needs mitigated via planned investments. It is also important to note that a single planned investment project may mitigate multiple grid needs that are identified in the GNA.

3 Review of DDOR Report

The 2018 DDOR Report submitted by PG&E consisted of the following Sections:

Section 1 – Distribution Resources Plan Objectives and Background

Section 2 – Mitigation of Grid Needs Identified in PG&E's 2018 GNA Report

Section 3 – Planned Investments

Section 4 – Candidate Deferral Opportunities

Section 5 – DER Distribution Service Requirements

Section 6 – Project Costs

Section 7 – Prioritization Metrics

Section 8 – Candidate Deferral Prioritization

Section 9 – Contingency Plans

Section 10 – Recommendations and Next Steps

Note: PG&E indicated during DPAG discussions that their 2018 DDOR is only a partial DDOR since it did not include voltage projects; however, they also indicated that they plan to include voltage projects in the 2019 DDOR.

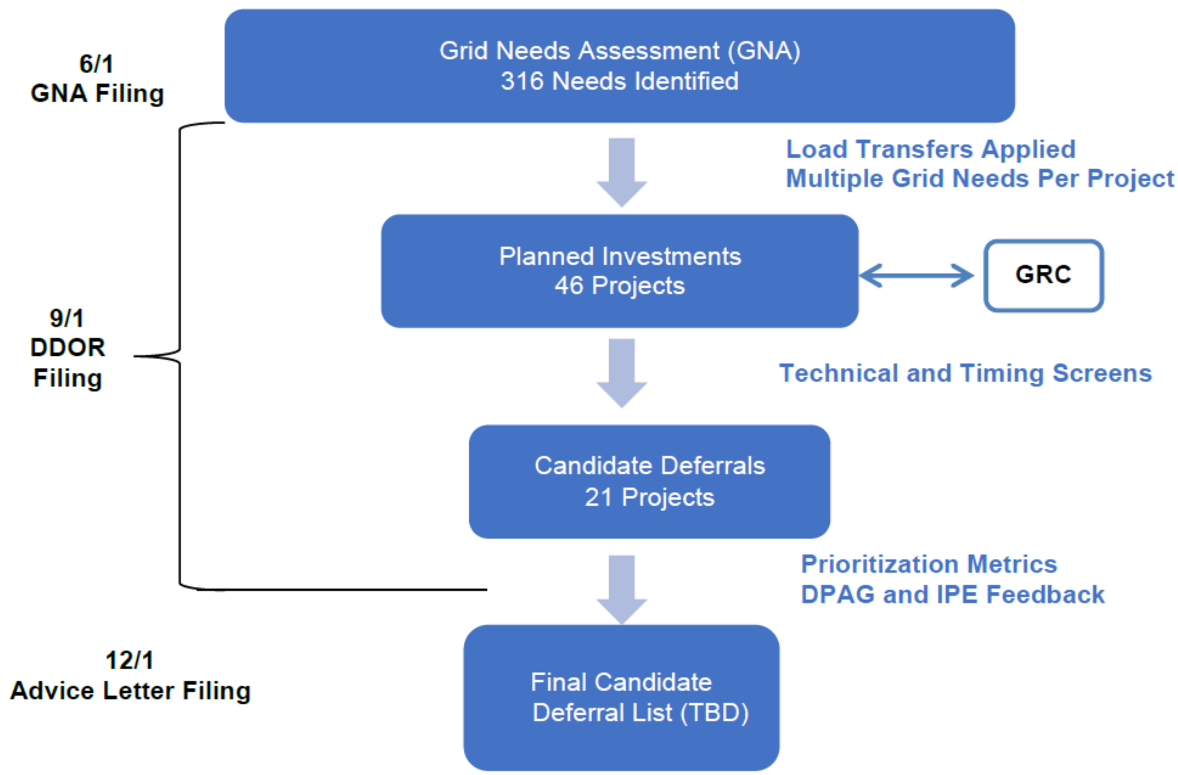
As part of their report, PG&E identified 21 candidate deferral opportunities totaling approximately 112 megawatts (MW), which were further categorized and prioritized into the following four tiers:

- Tier 1: Identified four candidate deferral opportunities totaling approximately 29.4 MW. Tier 1 projects are relatively more likely to be deferrable projects.
- Tier 2: Identified four candidate deferral opportunities totaling approximately 13.0 MW. Tier 2 projects have identified some red flags that indicate they are unlikely to be successfully deferred now. PG&E recommends not pursuing these projects, but to closely monitor status and project conditions and re-evaluate for a future date.
- Tier 3: Identified eleven candidate deferral opportunities totaling approximately 62.1 MW. Tier 3 projects have multiple major red flags that have been identified and indicate it is not likely a DER deferral solution can successfully be sourced.

- Tier 4: Identified two candidate deferral opportunities totaling 7.2 MW. Tier 4 projects have already been sourced for DER deferral solutions and/or currently have pending decisions at the Commission, and thus are not considered for this DDOR.

Figure 3-1 shows the overall DIDF process used by PG&E and the project counts at each step of the process.

Figure 3-1: Overall DIDF Process and the Project Counts at Each Step



PG&E included several costs of interest in its DDOR Report including:

- An estimate of the cost of implmenting each project listed as Candidate Defferal Projects as shown in the table below which was Appendix C in the DDOR Report. These cost estimates are based upon the cost of previously completed similar projects and are reffered to a Unit Cost Estimates.
- An estimated LNBA deferral value range in $/kW-year for each project. This value was provided to give developers an idea of the deferral value of each project. PG&E used three ranges – 1) $0-$100, 2) $100 to $500 and 3) greater that $500.

Shown in Figure 3-2 on the following page is a copy of Appendix C of PG&E's DDOR which includes all Candidate Deferal Projects.

Figure 3-2: Appendix C of PG&E DDOR Report

Appendix C **Candidate Deferrals**

Division	Candidate Deferral	Proposed Work	In-Service Date	Distribution Service Required	Estimated LNBA Range ($/kW-yr.)	Unit Cost of Traditional Mitigation ($k)	Expected performance and operational requirements					
							GNA Facility Name	Grid Need (MW)	Month	Days/ Year	Hours	Duration (Hours)
Central Coast	Dolan Road Bank 1	Install new bank at Dolan Road Substation	5/1/2021	Capacity	$100-$500	$6,500	DOLAN ROAD BANK 1	3.99	Apr-Oct	214	6:00AM-10:00PM	16
Central Coast	Gonzales Bank 3	Replace Gonzales Bank #3	5/1/2021	Capacity	$100-$500	$5,500	GONZALES BANK 3	0.50	Jun-Sep	12	8:00AM-12:00PM, 5:00PM-9:00PM	8
							GONZALES BANK 4	1.50	Jun-Sep	12	8:00AM-4:00PM	8
Central Coast	Camp Evers 2107	Install Camp Evers 2107 to reduce the number of customers on Camp Evers 2106	5/1/2022	Reliability / Other	$100-$500	$1,485	CAMP EVERS 2106	1.20	Jan-Dec	365	12:00AM-12:00AM	24
Central Coast	Salinas 1102	Replace recloser and booster to transfer and reduce number of customers	12/1/2022	Reliability / Other	$0-$100	$250	SALINAS 1102	2.23	Jan-Dec	365	12:00AM-12:00AM	24
Diablo	Brentwood 2104	Install new feeder at Brentwood to reduce the load on Brentwood 2112 and Contra Costa 2113	5/1/2021	Reliability / Other	$0-$100	$1,250	BRENTWOOD 2112	3.68	Apr-Aug	153	12:00AM-12:00AM	24
							CONTRA COSTA 2113	2.10	Jun-Aug	92	12:00AM-12:00AM	24
Fresno	Alpaugh 1102	Install new feeder at Alpaugh Substation	4/1/2024	Capacity	$0-$100	$3,250	CORCORAN BANK 3	5.81	Jun-Aug	92	10:00AM-11:00PM	13
							CORCORAN 1112	0.69	Jun-Aug	79	2:00PM-8:00PM	6
							CORCORAN 1116	2.22	May-Aug	123	12:00AM-12:00AM	24
							CORCORAN BANK 4	6.01	Jun-Aug	92	7:00AM-12:00AM	17
							CORCORAN 1106	2.14	May-Aug	123	6:00AM-12:00AM	18
							ANGIOLA BANK 1	2.03	May-Aug	105	7:00AM-12:00AM	17
Fresno	Calflax Bank 2	Install new Bank #2 at Calflax Substation - 30 MVA Bank	4/1/2023	Capacity	$100-$500	$5,000	CALFLAX BANK 1	3.86	Jun-Aug	92	12:00AM-12:00AM	24
Fresno	Huron Bank 1	Replace Huron Bank 1 due to off peak overloaded - 30 MVA Bank	4/1/2021	Capacity	$100-$500	$6,000	HURON BANK 1	3.21	Jun-Aug	46	12:00PM-9:00PM	9
							HURON BANK 1	-1.30	Apr-Oct	210	10:00AM-3:00PM	6

Division	Candidate Deferral	Proposed Work	In-Service Date	Distribution Service Required	Estimated LNBA Range ($/kW-yr.)	Unit Cost of Traditional Mitigation ($k)	Expected performance and operational requirements					
							GNA Facility Name	Grid Need (MW)	Month	Days/ Year	Hours	Duration (Hours)
Los Padres	Estrella Substation	Construct Estrella Substation - 1-45 MVA transformer and fully populated switchgear enclosure	5/1/2024	Capacity	$100-$500	$10,000	PASO ROBLES 1103	0.42	Jun-Aug	69	2:00PM-4:00PM	2
							PASO ROBLES 1107	0.25	Jun-Aug	66	3:00PM-5:00PM	2
							PASO ROBLES 1108	0.18	Jun-Aug	66	3:00PM-4:00PM	1
							SAN MIGUEL BANK 1	1.53	July-Aug	46	3:00PM-9:00PM	6
							SAN MIGUEL 1104	0.28	Jun-Aug	69	6:00PM-8:00PM	2
							TEMPLETON BANK 2	0.75	Jun-Aug	46	2:00PM-4:00PM	2
Los Padres	Oceano 1108	Replace conductor on and transfer customers to Oceano 1108 to reduce the number of customers on Oceano 1106	1/1/2022	Reliability / Other	$0-$100	$425	OCEANO 1106	1.18	Jan-Dec	365	12:00AM-12:00AM	24
Mission	San Leandro U 1107	Install switches to allow transfer to reduce the number of customers	12/1/2021	Reliability / Other	$0-$100	$200	SAN LEANDRO U 1107	0.37	Jan-Dec	365	12:00AM-12:00AM	24
North Bay	Pueblo Bank 3	Replace Pueblo Bank #1 with a 45 MVA transformer to eliminate a 17.5 MW Emergency Bank loss deficiency	6/1/2022	Reliability / Other	$0-$100	$6,000	PUEBLO BANK 1	17.50	May-Sept	153	12:00PM-12:00AM	12
San Francisco	SF H 1107 (Martin)	Replace conductor and transfer customers to reduce the number of customers	12/1/2022	Reliability / Other	$0-$100	$150	SF H 1107 (MARTIN)	1.55	Jan-Dec	365	12:00AM-12:00AM	24
San Francisco	SF H 1108 (Martin)	Replace switches and transfer and reduce number of customers	12/1/2022	Reliability / Other	$0-$100	$180	SF H 1108 (MARTIN)	1.26	Jan-Dec	365	12:00AM-12:00AM	24
San Jose	Santa Teresa Substation	Construct Santa Teresa Substation - 1-45 MVA transformer and 21 kV outdoor bus to serve new customer load	5/1/2021	Capacity	$0-$100	$14,100	EDENVALE BANK 2	2.35	Jun-Aug	69	3:00PM-6:00PM	3
							EDENVALE BANK 4	6.07	May-Sept	144	12:00PM-8:00PM	8
							EDENVALE 2111	6.98	Jan-Dec	290	8:00AM-9:00PM	13
							EDENVALE BANK 3	0.99	Jun-Aug	63	4:00PM-6:00PM	2
							EDENVALE 2110	2.91	May-Oct	132	9:00AM-7:00PM	10
San Jose	Llagas Substation	Offset demand and reduce loading on Llagas.	5/1/2022	Capacity	$100-$500	$5,519	LLAGAS BANK 3	5.18	Jun-Aug	90	12:00PM-7:00PM	7

Division	Candidate Deferral	Proposed Work	In-Service Date	Distribution Service Required	Estimated LNBA Range ($/kW-yr.)	Unit Cost of Traditional Mitigation ($k)	Expected performance and operational requirements					
							GNA Facility Name	Grid Need (MW)	Month	Days/ Year	Hours	Duration (Hours)
San Jose	New FMC Feeder	Install 1-12 kV feeder at FMC to reduce the load on FMC 1101 and El Patio 1112	6/1/2023	Reliability / Other	$0-$100	$1,250	FMC 1101	3.45	June-Aug	92	12:00AM-12:00AM	24
							EL PATIO 1112	0.51	July-Aug	62	12:00AM-12:00AM	24
Sierra	Bogue Feeder	Install 1-12 kV feeder at Bogue to reduce the load on Bogue 1105, Bogue 1102, and Bogue 1103	6/1/2021	Reliability / Other	$0-$100	$1,250	BOGUE 1105	1.23	June-Aug	92	12:00AM-12:00PM	24
							BOGUE 1102	0.18	July-Aug	62	12:00AM-12:00AM	24
							BOGUE 1103	0.31	July-Aug	62	12:00AM-12:00AM	24
Stockton	New Lammers Feeder	Install new feeder at Lammers on existing switchgear, no substation work required	6/1/2021	Capacity	$100-$500	$2,600	LAMMERS 1101	1.24	May-Oct	130	6:00AM-6:00PM	12
Yosemite	Santa Nella Bank 1 and New Feeder	Replace existing Santa Nella Bank #1 with a 30 MVA unit and install 1-12 kV feeder.	5/1/2022	Capacity	$100-$500	$7,500	CANAL 1102	0.31	Jun-Aug	69	3:00PM-6:00PM	3
							CANAL 1103	1.26	Jun-Aug	92	1:00PM-6:00PM	5
							CANAL BANK 2	2.78	Jun-Aug	84	2:00PM-7:00PM	5
							ORTIGA BANK 1	1.35	Jun-Aug	92	2:00PM-8:00PM	6
Yosemite	New Dairyland Feeder	Install new feeder on Dairyland	4/1/2022	Capacity	$0-$100	$3,250	DAIRYLAND BANK 1	7.97	May-Oct	166	12:00AM-12:00AM	24

Shown in Figure 3-3 is Table 1 of PG&Es DDOR Report which lists the 21 projects that were selected for further consideration. PG&E proposed that Tier 1 projects proceed to procurement and that Tier 2 and 3 projects were the next two groups in priority order but are not recommended to proceed to procurement. Tier 4 includes projects that are already designated as DER projects. Note that this table has been updated since the DDOR Report was filed; change have been made based upon DPGS comments, updated load forecasts based upon recent load data and additional distribution circuit loading analysis.

Figure 3-3: Table 1 from PG&E DDOR Report

Table 1: PG&E's 2018 DDOR Candidate Deferral Location Summary

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)
1	New Lammers Feeder	6/1/2021	1.2
	Huron Bank 1	4/1/2021	3.2
	Santa Nella Bank 1 and New Feeder	5/1/2022	5.7
	Santa Teresa Substation	5/1/2021	19.3
2	Dolan Road Bank 1	5/1/2021	4.0
	Bogue Feeder	6/1/2021	1.7
	Estrella Substation	5/1/2024	3.4
	Calflax Bank 2	4/1/2023	3.9
3	Brentwood 2104	5/1/2021	5.8
	Pueblo Bank 3	6/1/2022	17.5
	Camp Evers 2107	5/1/2022	1.2
	Salinas 1102	12/1/2022	2.2
	Oceano 1108	1/1/2022	1.2
	San Leandro U 1107	12/1/2022	1.6
	SF H 1107 (Martin)	12/1/2021	0.4
	SF H 1108 (Martin)	12/1/2022	1.3
	New Dairyland Feeder	4/1/2022	8.0
	Alpaugh 1102	4/1/2024	18.9
	New FMC Feeder	6/1/2023	4.0
4	Gonzales Bank 3	5/1/2021	2.0
	Llagas Substation	5/1/2022	5.2

PG&E LNBA Calculation

We reviewed the methodology that PG&E used to develop the LNBA values that it included in its DDOR Report. A summary of that review follows.

PG&E used the 5-year deferral value of the proposed (wire) solution in calculating the Locational Net Benefit Analysis (LNBA) value. Note their analysis has since been updated and shared with the DPAG to reflect the potential deferral of projects until the end of the planning period (2027).

The 5-year deferral value is the sum of the Net Present Values (NPV) of the 1-year deferral value of the proposed solution for the first five years. The 1-year deferral value of the proposed solution is the sum of the 1-year deferral value of the equipment capital cost and the operations and maintenance (O&M costs) associated with the new equipment that would have been added if the traditional projects had been built.

The 1-year deferral value associated with equipment is calculated by multiplying the revenue requirement for the project with the RECC factor.

1-Year deferral value = Project Revenue Requirement * RECC,

Where RECC is defined by the following equation:

$$\text{RECC} = \frac{(r-i)}{(1+r)}\left(\frac{(1+r)^N}{(1+r)^N-(1+i)^N}\right)$$

Where, i = assumed inflation over the period of interest, r = assumed discount rate and N = is the assumed life of the traditional project.

The Project Revenue Requirement is calculated by multiplying the estimated capital cost of the equipment with the Revenue Requirement Multiplier (RRQ Multiplier). The RRQ Multiplier represents costs recovered from utility customers and includes costs such as taxes, franchise fees, utility authorized rate of return, and overheads. In equation form, the Project Revenue Requirement is

Project Revenue Requirement = Estimated Project Capital Cost * RRQ Multiplier

If a DER is procured instead of building a traditional wires project, utility customers also benefit by avoiding any annual O&M activities associated with the traditional wires project equipment which is not built. Since O&M is an expense item that is passed to customers in the year it is incurred, it is not multiplied by the RECC factor or the RRM. Since O&M costs are incurred in the year they are performed O&M is also subject to inflation adjustments.

The complete expression of the cost reduction associated with a one-year deferral is thus:

Deferral Benefit = [Project Capital Cost] x [RECC Factor] x [RRQ Multiplier] + annual O&M]

To calculate the value of a multiple-year deferral, the -yearly deferral values for each year after the first year are calculated and simply discounted to a present value using a discount factor derived from same discount and inflation rates used in the RECC factor and then discounted vales are summed together to form the multiply year deferral value.

The key assumptions for the LNBA calculation include the following:

- Discount rate: Derived from the utility's weighted average cost of capital.
- Inflation rate: Inflation rates for equipment and O&M as assumed as per utility's practice.
- Life of a traditional project: Assumptions for project life as per utility's practice.
- Equipment Capital Cost: Cost of the project equipment as per utility's practice.
- O&M costs: Cost of O&M as per utility's practice. Expressed as a percentage of the project's capital cost.

In general, PG&E's LNBA calculations followed the same calculations as those included in the E3 LNBA tool. However, PG&E used their own set of assumptions for the key inputs to the deferral calculation.

Based upon our review we found that all of the PG&E LNBA calculations were consistently calculated with the methodology summarized above.

4 Review of DPAG Meetings

PG&E held three DPAG meetings or conference calls on September 14th, 27th and October 25th. This section reviews these meetings and in particular the content of those meetings that led up to the development of the projects proposed to proceed to procurement and the technical requirements of the projects that were proposed for procurement.

PG&E's last recommended project prioritization[1], which was presented at its October 25th DPAG meeting is shown below in Table 4-2 below. There are still 21 projects in the four tiers as proposed in the DDOR Report and the initial DPAG meeting but there have been some changes to projects that were included in Tiers 1, 2 and 3. Namely, the following changes were made since the first DPAG meeting:

- Santa Teresa Substation was in Tier 1 and now is recommended to be in Tier 2
- Bogue Feeder was in Tier 2 and now is recommended to be in Tier 3
- Calfax Bank 2 was in Tier 2 and now is recommended to be in Tier 3
- A number of technical requirements changed for some projects that resulted in larger needs

PG&E's changes to its recommended projects and needs reflected additional work that was completed since the work that led up to the DDOR Report. This included performing additional detailed engineering analysis to refine expected performance and operational requirements, including:

- Examination of longer deferral terms (i.e., through the full planning horizon rather than just 5 years as was the case in the GNA/DDOR)
- Updated its load forecast to reflect any significant changes (e.g., new customer requests, etc.); the recommendations in the DDOR report were based upon peak load data captured during the peak in 2017 (primarily during the summer). Data for an additional peak season (2018) is now available.
- Examination of historical SCADA data to get up to date loads and load shapes
- Examination of grid topology and the interdependencies of grid needs to ensure that all load transfer opportunities have been taken advantage of as well as all assumed load transfers are still available and viable solutions
- Examination of temperature data to examine how often overload is expected to occur

[1] PG&E indicated that they will continue to refine their analysis of the candidate projects and their requirement and the final results will be reflected in their December 1, 2018 Advice Letter

- Revisited its DDOR project prioritization based upon discussions during the DPAG meetings

Figure 4-2 shows PG&E's final project prioritization presented to the DPAG at its October 25th meeting. It shows the overall ranking of projects based upon the three categories defined by the CPUC – Cost-effectiveness, Forecast Certainty, and Market Assessment. PG&E indicated that they will continue to refine their analysis of the candidate projects and their detailed requirements and the final results will be reflected in their December 1, 2018 Advice Letter.

PG&E used the following 4-tier color coding system to represent is prioritization results, where each tier represents PG&E's proposed priority ranking of those candidate deferral projects' likelihood of success for DER sourcing. Note these tiers are not the same as the four tiers used to group the 21 projects. Note that all ranking of projects is relative and a red ranking indicates that there is a "red flag" associated with the candidate deferral opportunity.

Figure 4-1: Final Project Prioritization

Tier	Color Designation	Definition
1		Relatively High Ranking
2		Relatively Moderate Ranking
3		Relatively Low Ranking
4		Already Sourced Elsewhere

Examples of potential red flags provided by PG&E:

	Market Assessment	Forecast Certainty	Cost Effectiveness
Red Flags	Continuous 24hr requirement or Baseload	Absence of SCADA, In-service date of 2024	Very low LNBA value

Figure 4-2: Final Overall Prioritization from PG&E's October 25th DPAG Meeting

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)	Prioritization Metrics: Cost Effectiveness	Prioritization Metrics: Forecast Certainty	Prioritization Metrics: Market Assessment
	New Lammers Feeder	6/1/2021	1.2			
1	Huron Bank 1	4/1/2021	3.7			
	Santa Nella Bank 1 and New Feeder	5/1/2022	8.1			
	Santa Teresa Substation	5/1/2021	30.3			
2	Dolan Road Bank 1	5/1/2021	6.0			
	Estrella Substation	5/1/2024	4.9			
	Bogue Feeder	6/1/2021	1.7			
	Calflax Bank 2	4/1/2023	3.9			
	Brentwood 2104	5/1/2021	5.8			
	Pueblo Bank 3	6/1/2022	17.5			
	Camp Evers 2107	5/1/2022	1.2			
	Salinas 1102	12/1/2022	2.2			
3	Oceano 1108	1/1/2022	1.9			
	San Leandro U 1107	12/1/2021	0.5			
	SF H 1107 (Martin)	12/1/2022	1.8			
	SF H 1108 (Martin)	12/1/2022	1.4			
	New Dairyland Feeder	4/1/2022	8.0			
	Alpaugh 1102	4/1/2024	18.9			
	New FMC Feeder	6/1/2023	4.0			
4	Gonzales Bank 3	5/1/2021	2.0			
	Llagas Substation	5/1/2022	5.2			

Figure 4-3 shows the detailed prioritization metrics for Tier 1 and 2 Projects that PG&E presented at the October 25, DPAG meeting. PG&E indicated that they will continue to refine their analysis of the candidate projects and their detailed requirements and the final results will be reflected in their December 1, 2018 Advice Letter.

Figure 4-3: Detailed Prioritization Metrics for Tier 1 and 2 Projects

Tier No	Candidate Deferral	Cost Effectiveness			Forecast Certainty			Market Assessment			
		Unit Cost ($k)	Estimated LNBA ($/kW-yr)	Estimated LNBA/kWh ($/kWh-yr)	Forecasted Need (Year)	SCADA Available (Y/N)	Customers on Asset	Days/ Year	Number of Grid Needs	Hours /Day	Overcapacity (%)
1	New Lammers Feeder	$2,600	$100-500	$100-500	6/1/2021	Y	2180	86	1	11	10%
1	Huron Bank 1	$6,000	$100-500	$100-500	4/1/2021	Y	1922	210	2	9	20%
1	Santa Nella Bank 1 and New Feeder	$7,500	$100-500	$100-500	5/1/2022	Y	2143	73	4	6	21%
2	Santa Teresa Substation	$14,100	$0-100	$0-100	5/1/2021	Y	479	365	4	24	58%
2	Dolan Road Bank 1	$6,500	$100-500	$0-100	5/1/2021	Y	3007	365	1	19	61%
2	Estrella Substation	$10,000	$100-500	>$500	5/1/2024	Y	1257	69	6	6	15%

Figure 4-4: PG&E's summary of its 21 candidate deferral project opportunities

- PG&E identified 21 candidate deferral opportunities (~130 MW):

Tier 1: Relatively more likely to be deferrable

- Three Candidate Opportunities (~13 MW)
- PG&E recommends pursuing competitive solicitations

Tier 2: Have some red flags

- Three Candidate Opportunities (~41 MW)
- PG&E recommends not pursuing these projects, but to closely monitor status and project conditions and re-evaluate for a future date

Tier 3: Have multiple major red flags

- Thirteen Candidate Opportunities (~69 MW)
- It is not likely a DER deferral solution can successfully be sourced

Tier 4: Have already been sourced for DER deferral solutions

- Two Candidate Opportunities (~7 MW)
- Are not considered for this DDOR

5 Review of Metrics and Prioritization

This section contains a discussion of the prioritization process and discussion of the various metrics PG&E calculated during that process. This section also describes a way to think about DER cost structures and why certain metrics might provide additional insights in the prioritization process.

As described earlier, PG&E used three overall ranking categories – Cost Effectiveness, Forecast Certainty and Market Assessment and three or four ranking metrics within each category as summarized below:

- **Cost-Effectiveness Metrics**
  - Unit Cost (Estimated Capital Cost of the Project)
  - Estimated LNBA ($/kW-yr) (Deferral value for each year of deferral)
  - Estimated LNBA/kWh ($/kWh-yr) (Ratio of LNBA value to kWh need per year)
- **Forecast Certainty Metrics**
  - Forecasted Need (Year) (Year that traditional project is needed)
  - SCADA Available (Y/N) (Whether the circuit or device is equipped with SCADA to allow for easy monitoring of load and load profiles)
  - Customers on Asset (Number of customers who could participate in DER solution)
- **Market Assessment Metrics**
  - Days/Year (number of days per year DER would need to be available to provide solution)
  - Number of Grid Needs (Number of different locations, normally number of circuits, that DER's would need to be located in order to solve grid need
  - Hours/Day (Maximum number of hours per day DER needs to be available to solve grid need)
  - Overcapacity (%) (Percent overload on the device or circuit)

As discussed earlier, PG&E used these three categories and ten metrics to rank candidate projects into three Tiers. We believe that the Cost Effectiveness category is somewhat different than the other two categories in that if there is not sufficient funds/budget[3] to develop and

[3] Funds/budget in this instance can also be thought of as head room – economic space in which to develop a project economic and still be under the cost cap.

operate a DER solution that is cost effective (one that results in a bid that is below the cost cap) then the other two categories become less important. In other words, the Cost Effectiveness category is somewhat of a threshold category. For this reason we have examined PG&E's candidate projects and their proposed prioritization from the Cost Effectiveness perspective in more detail than the other two categories, although the other two categories remain critical to the overall prioritization process and poor scores in the other categories could result in an overall low ranking. In the next section we discuss one way to think about DER cost structures and how that can help in the project prioritization process.

It must be noted however, that if a project looks favorable on a cost effectiveness basis it does not mean that it should automatically receive an overall high ranking because there may be significant issues/red flags in the other two prioritization categories that could result in a lower overall ranking.

5.1 DER Cost Structure and Metrics

The cost effectiveness portion of the project prioritization process is aimed in part to determine which candidate projects are most likely to be cost-effectively deferred by one or more DERs. Thus it is an attempt to gauge whether the cost to develop and operate one or more DERs will be less than the cost cap that is derived from the capital and O&M cost of the traditional project. Thus it is important to give some thought to what affects the cost of developing and operating a DER project. For our purposes we are suggesting here one way to look at the cost of developing a DER or in other words one possible DER cost structure. A simple cost structure would include cost drivers broken out as follows:

1. Costs of participating in the procurement process up to the point of CPUC approval and execution of the DER agreement.

2. Costs associated with providing the capacity to meet the maximum need requirement in any given year.

3. Costs associated with providing the capacity to meet the maximum number of hours of need in any day (this is also something akin to providing "energy" and will be called energy going forward).

4. Cost associated with providing the capacity and "energy" need for the maximum number of days of need in a year.

In considering these cost drivers, a DER's project could be a function of all of these drivers or primarily a function of two or three. We will give examples of what this means in the discussion below.

Procurement Participation Process Costs

The costs in Item 1 include all costs that are required to win and execute a DER purchase agreement. It includes cost that are independent of the type of DER proposed and other costs will vary with the amount of detail work that is necessary to put a complete bid together and to support all of the procurement, negotiations, regulatory steps to reach final close.

The costs includes participating in the procurement process meetings/calls, understanding the many nuances in the process (i.e. double counting and incrementality, obtaining an interconnection agreement, RA and other potential additional value streams, what values are considered in the selection process, etc.), understanding the procurement rules, the bidding rules and requirements, the pro-forma contract requirements including a DER's obligations and risks. It also includes participating in developing best and final bids and negotiations with the utilities. For most technologies the cost of developing a conceptual design and pricing out the solution would be in this category.

There are some costs experienced during this period that may vary with the complexity of the project for example, the effort and cost of developing an EE solution design for bidding purposes may increase somewhat with the size of the proposed size of the EE bid.

However, in general, one can think about these costs as primarily a fixed cost of participating in the procurement process and one that is not heavily influenced by the size of the proposed project. We estimate that these costs, which must cover the cost of time spent by technical, commercial, and legal specialists, could easily reach seventy five to a hundred thousand dollars ($75-$100,000) and possibly more. We believe that all DER projects have costs that are a function of this driver.

Costs Associated with Maximum Capacity Requirements

These are the costs associated with developing, implementing and operating the DER project that can meet the maximum capacity requirement during the full course of the DER PPA. As a simple example, these would be the cost of developing a DER battery project of sufficient capability to meet the maximum capacity requirement of 2 MWs. It is the cost of developing a battery that has a 2 MW capacity which can deliver that capacity for an hour. In other words, it is a battery rated at 2 MW, 2MWh. We believe that all DER projects have costs that are a function of this driver.

Costs Associated with Maximum Daily “Energy” Requirements

These are the costs associated with developing, implementing and operating the DER project that can meet the maximum daily “energy” requirements over the course of the DER PPA. Again a simple example, these are the cost of developing a DER battery project to meet the maximum demand requirement of 2 MWs that also has a maximum number of hours of need of 6 hours. It is the cost of developing a battery that has a 2 MW capacity which can deliver that capacity for six hour. In other words, it is a 2MW, 12MWh battery. We believe that many DER projects have costs that are a function of this driver.

Costs Associated with Maximum Number of Days per Year "Energy" Requirements

These are the costs associated with developing, implementing and operating the DER project that can meet the maximum capacity and energy need requirements on all of the days of need in a year during the DER PPA. Again a simple example, these are the cost of developing a DER battery project to meet the maximum demand requirement of 2 MWs that has a maximum number of hours of need of 6 hours for 160 days per year during March through November. It is the cost of developing a battery that has a 2 MW capacity which can deliver that capacity for six hour. In other words, it is a 2MW, 12MWh battery that can be deployed for 160 days per year during March through November. For the battery example, these costs are likely to be similar or that same as the costs to meet the Maximum Daily "Energy" Requirements since if the need can be met on one day it should be able to be met on 160 days with no real additional project cost. But not all DER technologies would have this same cost structure. For example a DR program that could meet the needs on the single maximum capacity and "energy" need day through an AC cycling program would likely have to increase the number of participants if the program would need to be called 160 times a year and may have to add other customer and DR technologies if the 160 days fell outside a period of heavy AC usage. Thus, for this DR example, there would be an additional cost to implement a DR DER program as a result of there being a high number of need days and the fact that some of those need days fall into a variety of seasons. We believe that this type of cost implication for a high number of days of need applies also to Energy Efficiency.

Implication for Prioritization Metrics

The previous discussion leads to the suggesting that prioritization based upon cost-effectiveness should capture the following:

1. Consideration of the absolute value of the cost of the traditional project because as this is reduced, the fixed cost of participating in the procurement process represents a larger part of the total funds available for the DER (and still be under the cost cap) which leaves less funds to actually implement and operate the DER project. This is considered by PG&E.

2. Consideration of the Maximum Capacity needs of the DER project. This is already reflected in the LNBA/kW-year metric used by PG&E however, as PG&E has pointed out this value is primarily meant to provide bidders insight into the deferral value of the project since it is developed for a five year deferral.

3. Consideration of the Maximum Daily "Energy" need of the DER project which was not expressly included in the ranking metrics listed by PG&E but these values were calculated by them. We consider this value to be one of the most important of the metrics for ranking purposes since it in one on sense captures the daily maximum capacity and energy need.

4. Consideration of the Maximum Number of Days need of the DER project.

When considering these metrics we must keep in mind the following additional cost drivers:

- The factors above do not capture the additional cost impact of projects that have a very large number of hours of need. For example, some projects with needs of 19 hours pose a much more complex problem to solve than a project with 8 hours. This might include the need to significantly oversize solutions and/or to have to find and alternative source of energy (PV or other generation or tie to another circuit) because there is not enough potential charging capability (kWhs) to charge a battery sufficiently to meet the discharge needs during the need period.

- These factors do not capture the potential increased cost for projects that require DER solutions at multiple locations for example on 3 to 5 separate circuits. Having to provide DER solution capacity will tend to increase the number of solution sites that need to be developed which along with other factors reduce the economies of scale.

We propose that considering all four of these in the prioritization process will increase the overall accuracy of the prioritization process. We applied the following factors to PG&E's 21 candidate projects:

1. Overall cost of the capital project.

2. Cost of the capital project/maximum kW need using PG&E's calculated value of LNBA $/kW-yr

3. Cost of the capital project/maximum daily "energy" need based upon the maximum of value of $/kWh per day

4. Cost of the capital project/annual "energy" need using PG&E's calculated value of LNBA $/kWh-yr

These factors are simple to calculate using information provided to the DPAG and could all have been calculated with values provided to the DPAG including project capital cost, maximum kW need, maximum kWh need and maximum number of days of need. There is no need to base these on the NVA values but in this case they were used since PG&E had already calculated the value for two of the three metrics.

Note that in this analysis the potential impact of additional revenue from the sale of other products (value stacking) is not reflected. If such value stacking net revenue (value after cost to deliver is considered) could be estimated it would serve to improve the cost-effectiveness of projects. The potential for value stacking is highly dependent upon the obligations of the deferral agreement. For example, the higher the number of hours of delivery per day and the higher the number of days of delivery per year will tend to decrease the ability to capture additional value.

5.2 Use of the Four Proposed Prioritization Metrics

We analyzed the Tier 1, 2 and 3 projects using the four cost effectiveness metrics discussed above.

Considering the first metric (estimated capital cost) there are five projects in Tier 3 that are under $450K which is definitely a warning flag for those projects. For projects this small, a large portion of the feasible “budget or headroom” goes toward the participation in the procurement process (perhaps 25% or more) leaving less to the development, implementation and operation of an actual DER solution. In our view, these projects belong in Tier 3 from a cost effectiveness point of view.

In considering the next three metrics (max capacity, max daily energy, max annual energy) we calculate these indices for all projects and then ranked the projects on each metric as shown in the following table. We believe that in consideration of the overall ranking of projects into the three Tiers, considering all three metric rankings is appropriate because each provide some insights. However, if only one metric could be used, we believe the $/kWh/Day is most insightful.

Before we examine the metric rankings, we should point out that the Estrella project has a need date in 2024. For this reason, PG&E has assigned a red flag in the Forecast Certainty category for this project. A need date or 2024 suggests that the factors that are projected to result in a need in 2024 were forecasts of things that would occur 6 years into the future[4]. In keeping with the just in time approach to planning and implementation to minimize ratepayer costs, we recommend that the Estrella project which has a need date of 2024 not be included in this year’s procurement cycle. Instead we recommend that it should be reexamined in the 2019 GNA/DDOR cycle.

Lastly, before we examine the results we should point out that these metrics look at the relative ordering of projects and are not an absolute metric of what can be cost effective or not.

We can see from the table below that the projects that PG&E proposed for Tier 1 have the highest overall rankings on the three metrics shown in the table after removing Estrella from the ranking – thus supporting their inclusion in Tier 1.

[4] The GNA and DDOR analysis was based upon 2017 peak load data and customer growth predictions based upon best information in early 2018.

Figure 5-1: Ranking Using Three Cost-Effectiveness Ranking

Tier No	Candidate Deferral	Cost	Ranking of Projects		
		Unit Cost ($k)	Rank $/kWh/Day	Rank LNBA $/kW-yr	Rank LNBA $/kWh-yr
1	New Lammers Feeder	$2,600	3	1	3
	Huron Bank 1	$6,000	2	3	4
	Santa Nella Bank 1 and New Feeder	$7,500	4	7	2
2	Santa Teresa Substation	$14,100	9	9	11
	Dolan Road Bank 1	$6,500	5	6	8
	Estrella Substation	$10,000	1	2	1
3	Bogue Feeder	$1,250	8	8	6
	Calflax Bank 2	$5,000	6	4	5
	Brentwood 2104	$1,250	16	14	14
	Pueblo Bank 3	$6,000	10	13	7
	Camp Evers 2107	$1,485	7	5	10
	Salinas 1102	$250	18	18	17
	Oceano 1108	$425	15	12	16
	San Leandro U 1107	$200	11	10	15
	SF H 1107 (Martin)	$150	19	19	19
	SF H 1108 (Martin)	$180	17	17	18
	New Dairyland Feeder	$3,250	12	11	12
	Alpaugh 1102	$3,250	14	16	13
	New FMC Feeder	$1,250	13	14	9
4	Gonzales Bank 3	$5,500	2	1	1
	Llagas Substation	$5,519	5	6	5

We then looked at the remaining projects to see if there were good candidates for Tier 1 that were currently in Tier 2 or 3. The projects that we focused on initially were Dolan Road Bank 1, Calflax Bank 2 and Camp Evers 2107 which are the projects with the next best set of rankings. In analyzing these projects we decided not only to look at the rankings but to look at the relative size of the metrics for each project when compared to the highest ranked project for each metric. For example we calculated the ratio of the value of the $/kWh/Day for the best project (which is Huron Bank 2 after Estrella is removed) by the value of the $/kWh/Day for each of the projects. The results are shown below in the table (Figure 5-2) for all three metrics.

Figure 5-2: Ranking and Ratios Using Three Cost-Effectiveness Ranking

Tier No	Candidate Deferral	Cost	Ranking of Projects			Ratio of First Rank Value to Value		
		Unit Cost ($k)	Rank $/kWh/ Day	Rank LNBA $/kW-yr	Rank LNBA $/kWh-yr	Ratio for $/kWh/ Day	Ratio for LNBA $/kW-yr	Ratio for LNBA $/kWh-yr
1	New Lammers Feeder	$2,600	3	1	3	1.2	1.0	1.4
	Huron Bank 1	$6,000	2	3	4	1.0	1.3	1.4
	Santa Nella Bank 1 and New Feeder	$7,500	4	7	2	1.4	2.2	1.0
2	Santa Teresa Substation	$14,100	9	9	11	8.0	4.5	30.4
	Dolan Road Bank 1	$6,500	5	6	8	4.2	1.9	19.9
	Estrella Substation	$10,000	1	2	1	0.5	1.0	0.4
3	Bogue Feeder	$1,250	8	8	6	7.9	2.9	8.7
	Calflax Bank 2	$5,000	6	4	5	4.4	1.6	5.3
	Brentwood 2104	$1,250	16	14	14	26.4	9.8	34.3
	Pueblo Bank 3	$6,000	10	13	7	8.3	6.1	16.7
	Camp Evers 2107	$1,485	7	5	10	4.6	1.7	22.5
	Salinas 1102	$250	18	18	17	50.6	18.9	248.0
	Oceano 1108	$425	15	12	16	25.1	5.8	75.8
	San Leandro U 1107	$200	11	10	15	13.0	4.7	61.5
	SF H 1107 (Martin)	$150	19	19	19	69.3	21.5	282.3
	SF H 1108 (Martin)	$180	17	17	18	43.4	15.8	207.9
	New Dairyland Feeder	$3,250	12	11	12	14.0	5.2	31.0
	Alpaugh 1102	$3,250	14	16	13	22.6	12.3	30.8
	New FMC Feeder	$1,250	13	14	9	18.1	6.7	21.3
4	Gonzales Bank 3	$5,500	2	1	1	0.7	0.8	0.1
	Llagas Substation	$5,519	5	6	5	1.6	2.0	1.9

Let's discuss what the additional values in the table mean. For example, if we look at the Santa Teresa Substation the value listed in the table under the column headed Ratio for $kWh/Day is 8.0. What this means is that the amount of funds (head room) available to develop the Santa Teresa Substation project and still be cost effective is 1/8th the amount of funds available on the Huron Bank 2 project from a cost per $/kWh per day perspective. In other words, the dollars per maximum daily kWh energy to be served by Santa Teresa Substation project is 12.5% (inverse of 8 expressed as a percentage) of the dollars available to the Huron Bank 2 project. When we examine the third metric we see that when considering maximum annual energy the funds available for Santa Teresa are 1/30th of the funds available for Huron Bank 2. From these two energy perspectives (daily and annual energy requirement) it appears that a DER project would have a difficult time cost-effectively deferring the Santa Teresa project.

Before we analyze the table it is important to make the point that we recommend considering all three metrics when considering cost-effectiveness. We tend to put a little more emphasis on tow metrics - the maximum capacity and maximum daily energy metrics. The third metric maximum annual energy is still meaningful and a project that ranks high on all three is good candidate but projects that rank high on the maximum capacity and maximum daily energy metrics and lower on the maximum annual energy metric may still be a viable candidate. Such a project would be more difficult for DER project that relies upon EE or DR technology to be cost effective because of the cost implications of having to provide capacity over multiple seasons.

Finally, these metrics are a simple way to think about cost-effectiveness but they do not capture all dimensions of cost. For example, if the number of days of need is 365, extra capability may have to be provided in the DER solution than if the number of days of need is say 300 days or if the number of hours of need is say 18 hours per day, this may require an unusual battery size (if it is feasible to charge it) or it may require a charging source on the circuit either of which will increase costs that are not captured by the simple cost model.

As we look at the table we see that the three recommended projects all have ratios close to one. This means that the funds to implement these projects per KW, per daily energy and per annual energy are all similar which further supports their placement in Tier 1. We can also see that as we look down the rest of the table that the other projects all have ratios that are much larger than one which means it is likely to be much more difficult to develop a cost effective DER solution for those projects when compared to the Tier 1 projects.

As we look at Dolan Road Bank 1, Calflax Bank 2 and Camp Evers 2107 we first note that the Calflax Bank 2 needs date is in 2023. We suggest, that as we did for Estrella, that the Calflax Bank 2 project be monitored and reconsidered in the 2019 DDOR cycle, in keeping with the just in time approach to making commitments to investments/PPAs to address distribution deficiencies.

As we look at the Dolan Road Bank 1 project next we see that although it is ranked 5th, 6th and 8th on the three metrics, the ratio for daily energy is 4.2 suggesting that the maximum daily energy requirement for this project that must be able to deliver for 19 hours makes it much more difficult to be cost effective than the recommended projects in Tier 1. The 365 days per year requirement for this project is the main driver for a ratio of nearly 20 for $/kW-yr. This is an example of a DER solution that has costs that are not captured by this simplified analysis since it appears that the DER solution will require some form of source to be added to the circuit to ensure sufficient charging can take place. This discussion suggests that the 4.2 and 19.9 ratios, for kWs per day and year respectively, are understating the difficulty of developing a cost-effective DER for this project and for this reason we recommend that it remain in Tier 2.

If we look at the Camp Evers 2107 project we see an even poorer cost-effective ratio (4.6) for the maximum daily energy need metric and thus developing a cost effective DER project to defer this project would be even more difficult than Dolan Road Bank 1. This project has a 24 hour per day and 365 day per year need which similar to Dolan Road will require additional steps to be taken to solve the deficiency making it even more difficult to develop a cost-effective DER than these simple metrics suggest. For these reasons we recommend that it remain in Tier 2.

We also included in the table the rankings of the Tier 4 projects as if they were included in the ranking along with the other projects. It is interesting to note that these two projects have had relatively high (good) rankings on all three metrics if they were included in the overall ranking of the Tier 1-3 projects and all three of their ratios are very favorable compared to the best projects in each of the three metrics.

Scanning the rest of the projects in the table it appears that for one reason or another, the remainder score even poorer as far as cost-effectiveness is concerned than the proposed Tier 1 projects.

Given this discussion we support the projects included in Tier 1 and believe that the projects included in Tiers 2 and 3 are much less likely to be cost effective and as result recommend that they remain in their current tier.

6 Responses to DPAG Comments

6.1 Issues Raised at the DPAG

The following issues were raised by the DPAG and followed up by the IPE.

Projects with 2020 Online Dates be Included in Procurement

A member of the DPAG raised the question:

> Can a planned investment project with a 2020 in-service date be included for DER procurement and implementation in this cycle if the need date is not in the summer but later in the year – i.e. in the winter?

The IPE pursued this question with PG&E and the results are summarized below.

- For projects with summer in-service dates there is insufficient time to procure, obtain regulatory approval, and develop the projects prior to their need for the summer season. This assumes that the procurement and regulatory processes require a similar amount of time to what was required during the IDER Pilot. This conclusion was reached based upon the analysis performed during the IDER Pilot process which was reviewed and confirmed by the IPE.
- There are 10 projects that had an expected in-service date of 2020. After review it was clear that all 10 projects had an in-service dates of June 2020 or earlier (Jan, May, and Jun)

Transmission Deferrals

A member of the DPAG raised the question:

> Is it possible that any transmission projects deferred could be deferred in addition to the distribution projects?

The IPE pursued this question with PG&E and the results are summarized below.

The table below, which shows transmission projects planned in the areas where distribution projects are also planned, was provided by PG&E. Generally, no transmission projects were found to be deferrable. The in-service date for the Santa Teresa and Estrella transmission projects are in the first half of next year, which is too soon to result in a deferral because of the later DDOR procurement cycle. The others were checked for projects at nearby substations. The DER load reduction impact for these areas was not sufficient enough to have any impact on the transmission projects.

A summary on the Tier 1 and Tier 2 Candidate Deferral projects and their possibility for Transmission Deferral can be found in Table 6-1.

Table 6-1: Transmission Deferral

Candidate Deferral	Distribution Need Date	MW Deficiency	MW Load	Transmission Deferral?
New Lammers Feeder	6/1/2021	1.2	55	No Transmission projects
Huron Bank 1	4/1/2021	3.7	8	No Transmission projects
Santa Nella Bank 1 and New Feeder	5/1/2022	8.1	8.2	No Transmission projects
Santa Teresa Substation	5/1/2021	30.3	NA	Non-deferrable (time) Transmission need date: 4/1/2019
Dolan Road Bank 1	5/1/2021	6.0	9.5	No Transmission projects
Estrella Substation	5/1/2024	4.9	NA	Non-deferrable (time) Transmission need date: 5/1/2019
Bogue Feeder	6/1/2021	1.7	30	No Transmission projects
Calflax Bank 2	4/1/2023	3.9	5.2	No Transmission projects

Examine Projects with Large Number of Hours of Need

A member of the DPAG raised the question:

> There are many projects on the PG&E list of candidate projects that have an unusually high number of hours of need per day. Some up to 24 hours per day. Is this right?

The IPE pursued this question with PG&E and the results are summarized below.

We looked at the list in general for this issue and in particular we looked at three specific projects. PG&E considers the names of the project that are discussed below to be protected materials under the DPAG nondisclosure agreement so we have substituted names for the three projects – they are now called Project 1, Project 2 and Project 3

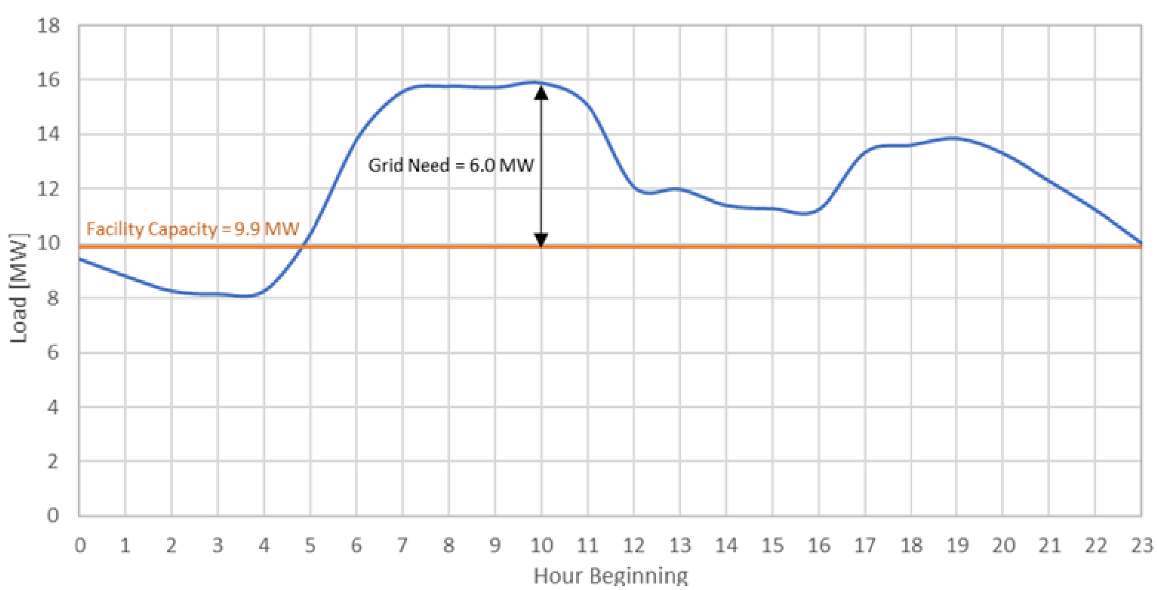
In general there are a group of projects that show a 24 hour need for 365 days per year. These projects are projects that have been included as a need on the basis of meeting a specific

PG&E distribution criteria which limits the number of customers on any one circuit to 6,000 customers. This policy is intended to limit the number of customers who are impacted by a single event – loss of the feeder. This is a common planning policy used in industry that is implemented in various ways – i.e. by imposing a maximum number of customers limit, a maximum load served limit, etc. These projects are implemented by splitting a circuit with high number of customers to two circuits. As such it is similar to providing a new service which is capacity that cannot be provided for by DER except in a mircro-grid arrangement.

Project 1

The load forecast for this project for the peak day in July 2021 shows a need for a large number of hours (17 hours in this case). We reviewed plots showing current load shape and the load shape of new load which were used to develop the plot below. This long duration need is driven predominately by commercial/industrial load with a large amount of new cultivation load, which is considered agricultural.

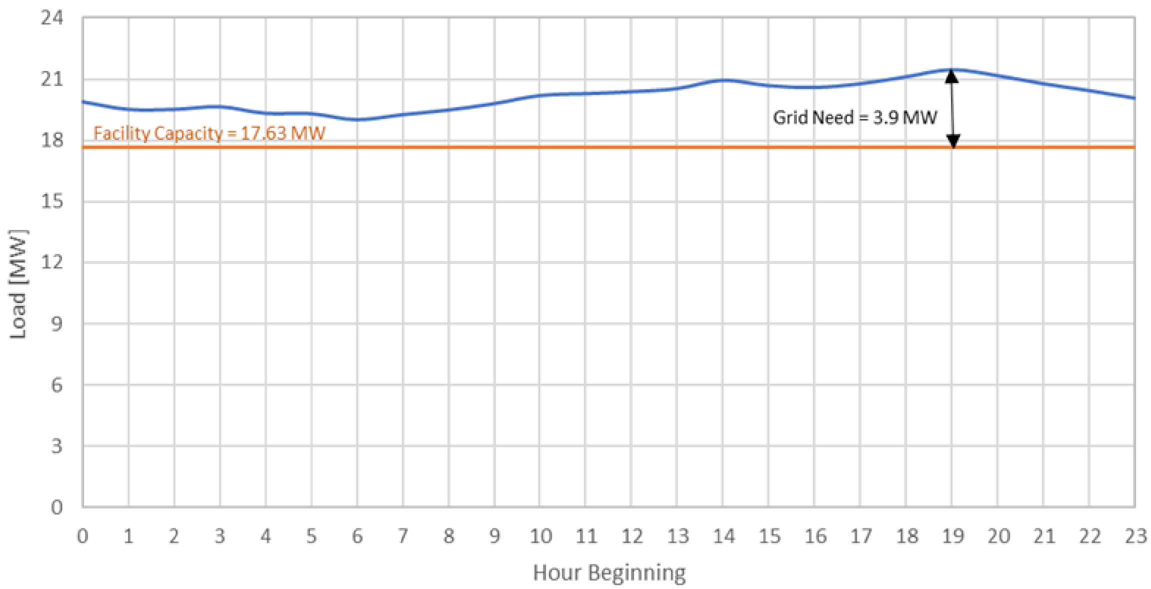
Figure 6-1: Project 1 Load Shape for Peak Day July 2021



Project 2

The load forecast for this project for the peak day in July 2027 shows a need for a large number of hours (24 hours in this case). We reviewed plots showing current load shape and the load shape of new load which were used to develop the plot below. This long duration need is driven in part by agricultural load, mostly pumping load, and therefore affected by the US Bureau of Reclamation’s annual water allocations from the Central Valley Water Project.

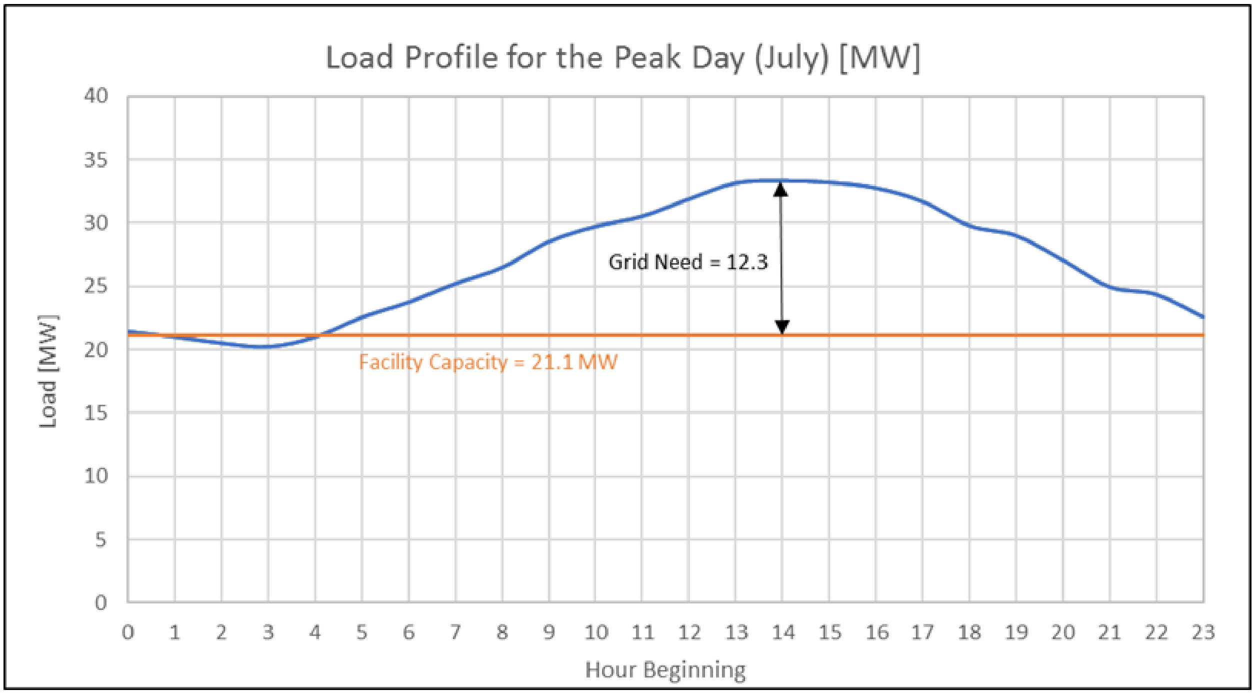
Figure 6-2: Project 2 Load Shape for Peak Day July 2027



Project 3

Project 3 loading is a result of many circuits that are supported by the Project 3 substation with composite loading spanning 24 hours.

Figure 6-3: Project 3 Load Shape for July



6.2 Responses Received From DPAG Questionnaire

PG&E sent a questionnaire to the DPAG members to solicit feedback about the DPAG process in general and in particular feedback on the project recommended for immediate competitive procurement and those that were not recommended for procurement. We worked with PG&E to develop the questionnaire which was developed in part to assist the IPE to achieve the objectives of supporting the DPAG. There were four responses as documented in Appendix A.

The stakeholder responses to the questions posed in the questionnaire are tabulated in Appendix A and in many cases there is a short response from the IPE which in general summaries points made in the body of the report.

7 Discussion of Other Items

Periods Assumed by PG&E

The following dates/periods of interest were provided in response to a data request sent to all three Utilities.

Table 7-1: Time Periods of Interest

Function	Years Included	Comments
Distribution Planning Period	2018 through 2027	
Period Covered by GNA	2018 through 2022	Five year period per CPUC decision.
Period Covered by DDOR	2018 through 2027	
DDOR LNBA Period	Five year period starting with year of need	Length of period should not affect the value of the LNBA/kW-yr since it is expressing the deferral value for only one year.
Advice Letter LNBA Period	Full deferral period (up to 7 years)	
Maximum Deferrable Period	From year of need to end of planning period (up to 7 years)	
Maximum Deferral Credit	From year of need to end of planning period (up to 7 years)	
Maximum Length of DER Contract	From year of need to end of planning period (up to 7 years)	

We can see that there is a mixture of time periods included in the GNA/DDOR process; we make recommendations regarding time periods in Section 8.

Approach to Stacking Value

The CPUC identified the concept of value stacking as an important concept to consider in the DDOR process. Two general approaches were identified to value stacking – developer value stacking and utility value stacking.

In developer stacking the DER agreement with the utility that results from the procurement process requires the developer to deliver just those attributes needed to defer the traditional project and the DER agreement would likely include limitations on the use of the DER when it would result in creating an additional/new need. An example of a limitation in a DER agreement would be the specification of hours during which a battery project would need to limit charging to avoid creating a new overload on the circuit. Under developer staking, the DER when not being dispatched to meet the "deferral attributes" would be available to the developer to be used to deliver other value as along as it operated within the limitation specified in the agreement.

In utility stacking the DER PPA that results from the procurement process requires the developer to make the full capability of the DER available to the utility who can then use it to maximize its value to ratepayers through its ability to fully dispatch the DER, limited only to the physical capability of the DER (as specified in the PPA).

PG&E indicated during the DPAG meetings that it is long (i.e. has a surplus) on all other products that might be procured from a DER and thus has no interest in following the utility stacking approach. They have developed a deferral PPA (for the IDER Pilots) such that they are procuring distribution capacity only and intend to follow the same approach for the PPAs that result from the 2019 DDOR procurement process. For example, applying this approach to an in front of the meter battery project, the DER would not buy or sell energy when charging or discharging under the PPA but would buy and sell energy in the wholesale market (or some other mechanism that does not involved the utility). PG&E has also indicated that it will dispatch the DER in the morning period prior to the day it is needed to allow the developer time to maximize any remaining value in the wholesale market.

8 Observations / Conclusions / Recommendations

Project Prioritization and Metrics

- We observe for the purpose of providing information to the DPAG to allow them to comment on the utilities prioritization based upon cost effectiveness that providing the LNBA range that a project falls into is not helpful if the ranges are broad and many projects fall into the same range.

- We recommend that for DPAG's purposes that the actual LNBA value be provided to allow them to gain insight into and to improve their ability to make sound suggestions in the prioritization process. PG&E provided this information in response to comments from the DPAG at the first meeting. If for some reason ranges continue to be the only option then we recommend much smaller ranges be used in the information that is provided to the DPAG.

- We observe that there are several ways to look at cost effectiveness by using multiple metrics. We recommend that in the future, the three metrics calculated in this report be provided to the DPAG. PG&E did provide several additional metrics in response to requests by the DPAG for more detailed information.

Recommended Projects for Tier 1

- We observe that in the DPAG process that PG&E has placed three projects into Tier 1 and are recommending these projects proceed immediately.

- We observe that PG&E used a three category, ten metric approach to the prioritization of candidate projects. We reviewed their application of these metrics in detail and conclude that they were applied accurately.

- We note that we preformed additional review of the candidate projects using three different metrics for cost-effectiveness. We conclude that the projects in Tier 1 are the candidate projects with a higher probability of success and that Tier 2 projects are less likely to be successful. We also conclude that from a cost-effectiveness point of view the Tier 2 projects are substantially less likely to be successful. For this reason we recommend that none of the Tier 2 project be moved to Tier 1.

Calendar Periods for GNA/DDOR

- We observe that the GNA has a five year time horizon and the distribution planning horizon is ten years. The DDOR was specified as a five year time horizon but PG&E has developed theirs for the planning period. PG&E eventually provided information on each project (i.e. maximum kW need, maximum hours of need, etc.) for the entire planning period.

- We recommend the CPUC revisit the time periods such that they better line up with the planning period and that they also line up with the procurement period. For example, if procurement will be through the end of the planning period the DDOR should also be the same period so that the information provided to the DPAG is what will drive the actual procurement. For example the time period used to develop the max kW need, max kW/day need, etc. that are used in the prioritization process should align with the procurement process timing.

Value Stacking

- As noted in the report, we observe that PG&E's DER proposed approach will be an agreement that buys services and not capacity, energy, RA or any other traditional electricity market products. PG&E's proposed agreement (based upon the contract version used for the IDER Pilot) is a DISTRIBUTION SERVICES AGREEMENT, that buys distribution capacity which is "provided by decreasing net loading on distribution infrastructure through decreasing electrical consumption or increasing generation, in accordance with the Operating Parameters set forth below to reduce thermal overload conditions and improve local distribution reliability and resiliency"

- We also observe in the IDER service contract provisions for limitations on the amount and timing of actions that would increase circuit loading.

- We conclude that PG&E's approach supports a developer staking approach to value stacking.

- We conclude that any value stacking in PG&E's procurement would be done by the developer/bidder and presumably reflected in their bid price.

LNBA Calculations

- We observe that PG&E followed the methodology in the E3 LNBA calculator in the calculation of LNBAs for their DDOR Report and also those that they shared with the DPAG as discussed in the body of the report. We also observe that PG&E used a unique set of assumptions in those LNBA calculations. We also observe in the review of other utilities that each uses a different set of assumptions in their calculation and in some cases the differences are more than insignificant. We are not concluding that any assumption is wrong but observing they are different.

- We observe that for the purpose of the DPAG discussions that LNBA values that are shared with the DPAG should be as consistent as possible with the values that will eventually be used in determining the deferral value in the procurement process. In this way prioritization of projects considering deferral value in the DPAG process would accurately represent the deferral values that are used in the procurement process.

- We recommend that the CPUC (possibly the ED) review the various LNBA assumptions made by the utilities for appropriateness given each utilities unique situation and also recommend reviewing with the utilities if the methodology used in the DDOR and DPAG is consistent with the methodology used in the procurement process. We recommend this review been done in a way that provides the appropriate level of confidentiality for any sensitive information used in the LNBA calculation.

Appendix A DPAG Survey Responses

Listed below are the responses received from the DPAG to the questions sent out by PG&E.

For this public version the table of questions and responses has been removed.

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-Attachment 4-

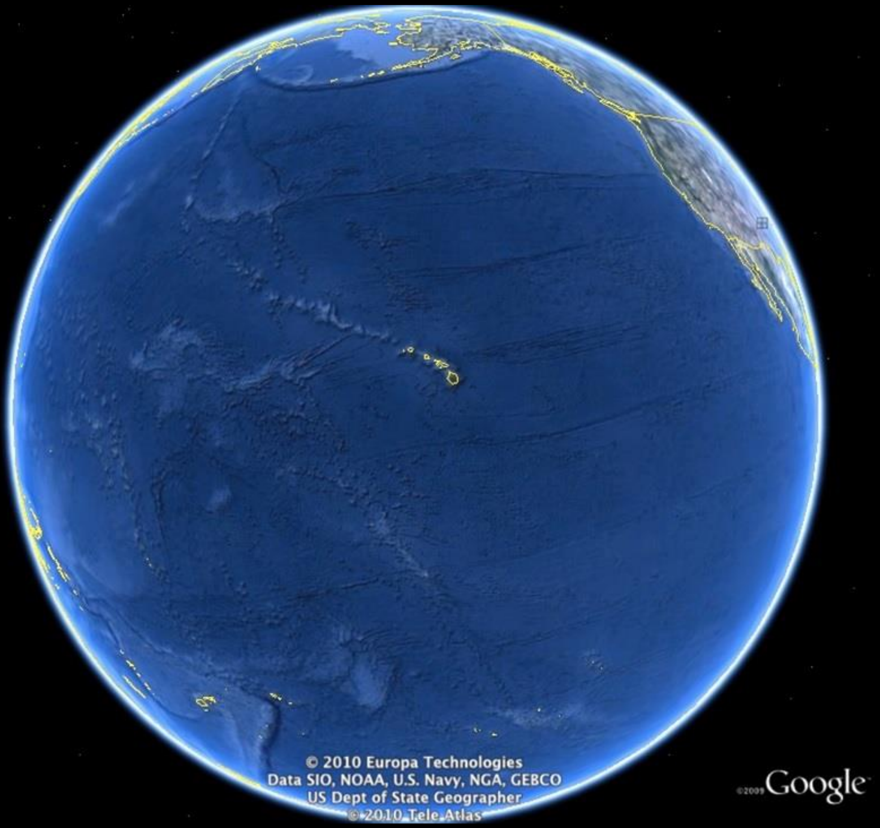
Presentation by Marc Assano of the Hawaiian Electric Company at the 2019 Smart Electric Power Grid Evolution Summit Regarding HECO’s Integrated Grid Planning Process

Integrated Grid Planning

Putting portfolio, transmission, and distribution planning into practice

Hawaiian Electric
Maui Electric
Hawai‘i Electric Light

July 31, 2019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US Dept of State Geographer
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Stakeholder Engagement Model

Hawaiian Electric Companies IGP Process

Education & Information ⇕ *Input & Feedback*

- Broad Public Engagement
- Stakeholder Council
- Technical Advisory Panel
- Individual Stakeholder Engagement
- Working Groups

The IGP Process will Expand Market Opportunities

Forecasts & Other Planning Inputs

Resource Needs Planning

Resources & Grid Services

2045 Long-Term Planning

Resource and T&D Needs & Long-term Considerations

5-year Resource Solution Sourcing

Resource Procurement (Grid-Scale, Aggregated DER/DR)

DER and DR Programs

Utility Resource Development

T&D Needs

(Resource)

T&D Needs Planning

(Non-Resource)

T&D Solution Sourcing

Targeted DER Programs

NWA Competitive Bid

Grid Modernization

Traditional Grid Solution Estimate

Solution/Bid Evaluation & 5yr IGP Plan

Grid Resources

Grid Services

NWA

Regulatory Approval

Seek PUC approval of IGP 5 year plan & related applications

Our *Customer First* DER Strategy is anchored by 3 objectives

1. Customer and independent distributed energy resources are essential to achieving our 100% renewable energy goal.
2. The utility must expand opportunities and facilitate participation for cost-effective distributed energy resources.
3. All customers must benefit from costs shared fairly, with no costs unfairly shifted.