PG&E'S 2020 DISTRIBUTION DEFERRAL OPPORTUNITY REPORT

Together, Building a Better California

August 17, 2020

Executive Summary

Pacific Gas and Electric Company ("PG&E") hereby submits its 2020 Distribution Deferral Opportunity Report ("DDOR") as directed by the California Public Utilities Commission's ("Commission" or "CPUC") Decision ("D.")18-02-004 and the Administrative Law Judge ("ALJ") Rulings from May 7, 2019, April 13, 2020, and May 11, 2020, in the Distribution Resources Plan ("DRP") Order Institute Rulemaking proceeding. This DDOR is submitted to the Commission, along with PG&E's 2020 Grid Needs Assessment ("GNA") Report, to comply with D.18-02-004. This 2020 DDOR builds off PG&E's 2020 GNA Report and identifies candidate distribution deferral opportunities for consideration of competitive solicitations for cost-effective Distributed Energy Resource ("DER") solutions to address identified distribution grid needs. This report is not subject to Commission approval and will be provided to the Distribution Planning Advisory Group ("DPAG") for review and comment. Specifically, this report will cover the following:

- Section 1 – Distribution Resources Plan Objectives and Background
- Section 2 – Mitigation of Grid Needs Identified in PG&E's 2020 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 Opportunities Prioritization
- Section 9 – Contingency Plans
- Section 10 – Recommendations and Next Steps

As part of this report, PG&E has identified 29 Candidate Deferral Opportunities totaling approximately 170 megawatts (MW), which are further categorized and prioritized into the following three tiers:

- Tier 1: Identified eight Candidate Deferral Opportunities totaling approximately 30 MW. Tier 1 Candidate Deferral Opportunities are relatively more likely to be deferrable.
- Tier 2: Identified thirteen Candidate Deferral Opportunities totaling approximately 40 MW. Tier 2 Candidate Deferral Opportunities have identified some red flags that indicate they are unlikely to be successfully deferred now. PG&E recommends not pursuing these Candidate Deferral Opportunities, but to closely monitor status and project conditions and re-evaluate for a future date.
- Tier 3: Identified eight Candidate Deferral Opportunities totaling approximately 100 MW. Tier 3 Candidate Deferral Opportunities have multiple major red flags

that have been identified and indicate it is not likely a DER deferral solution can successfully be sourced.

The following table summarizes PG&E's 2020 DDOR Candidate Deferral Opportunities including location, targeted in-service need date, and minimum grid capacity needed (i.e., deficiency).

Table 1: PG&E's 2020 DDOR Candidate Deferral Opportunities Summary

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)
1	Willow Pass Bank 1	2023	5.3
	San Miguel Bank 2	2023	5.0
	Calistoga Bank 1	2023	4.2
	Ripon 1705	2024	3.7
	Blackwell Bank 1	2023	[redacted]
	Belle Haven Bank 4	2023	5.0
	San Luis Obispo 1106	2023	[redacted]
	Zamora 1108	2023	1.1
2	Dunnigan Bank 1	2024	1.6
	Beresford 401 Cut-Over	2023	1.5
	Brentwood 2111 Line Work	2023	0.9
	Hollister 2106 Line Work	2023	5.0
	Rocklin 1104 and Rocklin 1101	2025	0.2
	Caruthers 1104 Regulator	2023	0.7
	Morgan Hill 2103	2023	6.6
	Storey 1103	2023	3.2
	Vasona 1109	2023	3.9
	Peabody 2106 Outlet	2024	[redacted]
	Stelling 1105	2023	4.6
	Mountain View Bank 1	2023	5.7
	Greenbrae Bank 2	2023	[redacted]
3	Woodland 1105 Outlet	2025	1.3
	Lockeford Bank 1	2024	14.8
	Semitropic 1112 Line Work	2024	8.1
	California 1103 & California 1111	2023	[redacted]
	Wolfe 1111 & Wolfe 1112	2023	44.1
	FMC 1102	2023	6.7
	Rincon Bank 1	2023	8.0
	Spence Bank 2	2023	[redacted]

PG&E's recommendation is to pursue competitive solicitations for only the Tier 1 Candidate Deferral Opportunities (eight projects totaling approximately 30 MW) now. PG&E does not recommend pursuing competitive solicitations for Tiers 2 and 3 currently due to the low likelihood of achieving a successful outcome. However, PG&E recommends closely monitoring the status and conditions of the Tier 2 Candidate Deferral Opportunities for future re-evaluation and consideration of competitive solicitations later.

PG&E will present the Candidate Deferral Opportunities and preliminary prioritization metrics to the DPAG by September 18, 2020. Based on feedback from the DPAG and the Independent Professional Engineer ("IPE"), PG&E will then submit the Final Candidate Deferral List by November 16, 2020.

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1. Distribution Resources Plan Objectives and Background

On August 14, 2014, the Commission instituted Rulemaking 14-08-013 to establish policies, procedures, and rules to guide the California investor-owned utilities ("IOU") in developing their DRP proposals. This rulemaking also established new polices to evaluate the IOUs' existing and future electric distribution infrastructure and planning procedures with respect to incorporating DERs into the planning and operations of their electric distribution systems.

In July 2015, California IOUs each submitted their respective DRP proposals to the Commission. The Commission organized the review of the DRP filing content into three tracks: Track 1 – Tools and Methodologies; Track 2 – Field Demonstration Projects; and Track 3 – Policy Issues.

In February 2018 the Commission issued D.18-02-004 on Track 3 Policy Issues, sub-track 1 (Growth Scenarios) and sub-track 3 (Distribution Investment and Deferral Process). This decision adopted the Distribution Investment Deferral Framework ("DIDF") and directed the IOUs to file a GNA by June 1 of each year, and a DDOR by September 1 of each year.[1] The DDOR will present a report of the IOUs' planned investments that provide one or more of the four distribution services adopted by D.16-12-036: capacity, voltage support, reliability (back tie) and resiliency (micro-grid).

In May 2019, the assigned ALJ issued a ruling modifying the DIDF process and updating the date upon which the IOUs submit the GNA and DDOR to August 15 of each year.[2]

In April 2020, the assigned ALJ issued a ruling modifying the DIDF process and filings with respect to the Independent Professional Engineer ("IPE") scope of work. This ruling also updated the 2020-2021 DIDF cycle schedule and defines the DIDF cycle to start on January 1 of each year and concludes July 31 the following year.

In May 2020, the assigned ALJ issued a ruling modifying the DIDF process. This ruling includes process changes to approval for the Integrated Energy Policy Report ("IEPR") dataset used for forecasting, requests for certain datasets to be hosted on the DRP Data Portals, value stacking that may result in deferral projects that exceed the cost cap, changes to how Locational Net Benefit Analysis ("LNBA") data is presented, and recommendations for potential 2021-2022 DIDF cycle reforms.

[1] D.18-02-004 O.P. 2.d.

[2] May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, p. 9. August 15, 2020 is a Saturday; therefore, PG&E's 2020 GNA and DDOR was filed on the next Business Day, August 17, 2020.

In June 2020, the assigned ALJ issued a ruling ordering PG&E to launch a DIDF request for offers ("RFO") for the Estrella Substation deferral opportunity to procure DERs to address capacity needs as identified in PG&E's 2020 GNA and DDOR filings.

This report fulfills the requirements associated with the DDOR that is not subject to Commission approval, as determined by D.18-02-004. This report will be provided to the DPAG for review and comment.

1.1. Objectives of the Distribution Deferral Opportunity Report

The objective of the DDOR is to utilize the GNA to identify PG&E's candidate distribution deferral opportunities shortlist. In addition, other objectives of the DDOR are to provide transparency into the assumptions and results of the distribution resources planning process that yield the DDOR candidate shortlist and provide the associated DER attributes required to meet these opportunities.

PG&E notes that the information in this DDOR represents PG&E's best information currently available on its electric distribution system, and is subject to change, including updates based on changes in system forecast and local loads, priorities for emergent work on electric distribution facilities, and the results of PG&E's rate cases, including the 2020 General Rate Case ("GRC").

1.2. Regulatory Timelines Associated with DDOR

PG&E's DDOR is required to be filed by August 15 of each year, concurrent with the GNA, and is provided to the DPAG[3] for advisory input. After PG&E files the DDOR and provides it to the DPAG, PG&E is required to initiate DPAG meetings. By November 15 of each year, PG&E will submit a Tier 2 advice letter requesting approval of the distribution deferral opportunities that were a result of the DPAG's advisory input on the DDOR. By January 15, or within 30 days of the Commission's disposition of this Tier 2 advice letter, PG&E will launch Competitive Solicitation Request for Offers ("RFO") for the identified distribution deferral opportunities.

The regulatory timelines associated with the DDOR and Competitive Solicitations was specified in the April 2020 ALJ Ruling[4] and is shown below:

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[3] As described in D.18-02-004, the DPAG is a distribution planning stakeholder group that provides advisory input on which distribution deferral opportunities should be pursued through competitive solicitation of DER non-wires solutions.

[4] April 13, 2020, Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, pp. 11-12

Table 2: DPAG Schedule for 2020-2021 DIDF Cycle

Activity*	Date*
Pre-DPAG 2020	
Pre-DPAG meetings and workshops, including Draft IPE Plans review	May 2020**
DPAG 2020	
IOU GNA/DDOR filings, Final IPE Plans circulated	August 15, 2020
IOUs update DRP Data Portals with GNA/DDOR data	August 30, 2020
IPE Preliminary Analysis of GNA/DDOR data adequacy circulated	September 5, 2020
DPAG meetings with each IOU	September 15, 2020 (week of)**
Participants provide questions and comments to IOUs and IPE	September 25, 2020
IOU responses to questions	October 5, 2020
Follow-up IOU meetings via webinar	October 10, 2020 (week of)**
DPAG 2020	
IPE DPAG Reports	October 25, 2020
DIDF Advice Letters submitted	November 15, 2020
Post-DPAG 2020 and 2021	
Provide draft RFO launch materials to Energy Division for approval in consultation with IPE and IE	December 10, 2020
Launch RFOs for DERs	January 15, 2021 (or within 30 days of DIDF Advice Letter approval if approval is after December 15, 2020)

Activity*	Date*
Annual DIDF reform comments due	January 20, 2021
IPE Post-DPAG Report	February 5, 2021
Comments on IPE Post-DPAG Report and replies to January 20 reform comments due	February 15, 2021

Notes:
*Activities and dates may be altered by Energy Division based on comments received during Pre-DPAG activities or as needed. Where dates fall on a weekend, the activity is intended to occur on the following Monday.

**Meeting dates to be assigned by Energy Division during the Pre-DPAG period.

Collectively, this process laid out in D.18-02-004 and summarized in Figure 1 below is referred to as the DIDF or the Distribution Resources Planning Process. This report completes the third stage of the process.

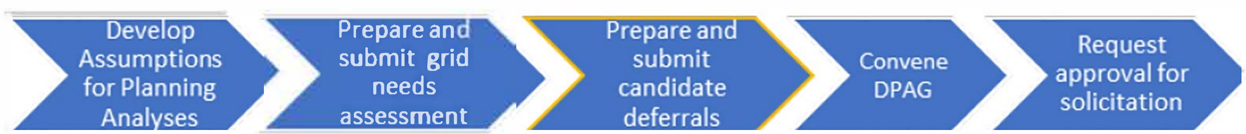

Figure 1: High Level Summary of Distribution Resources Planning Process

1.3. Distribution Investment Deferral Framework Process

Figure 2 illustrates the Distribution Investment Deferral Process. The process acts as a funnel to identify candidate deferral projects, based on the grid needs identified in the GNA.

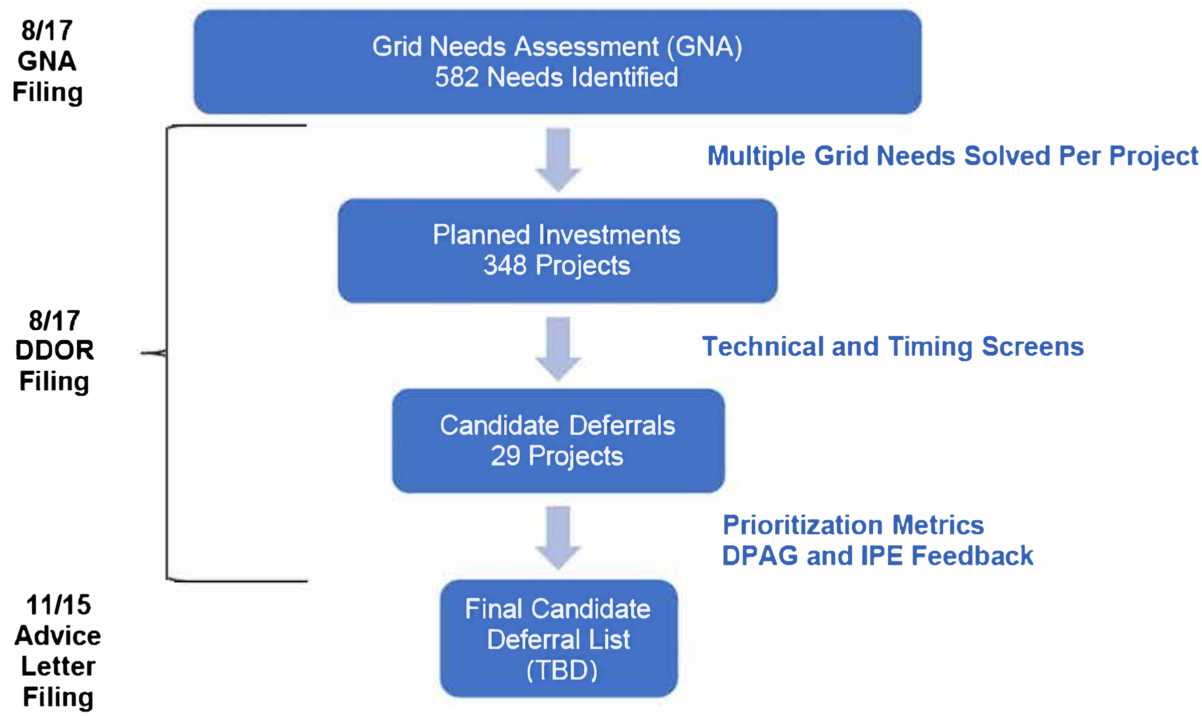

Figure 2: Illustration of Process to Identify Final Candidate Deferral Opportunities from GNA

PG&E's 2020 GNA filing identified 582 grid needs. The grid needs for the 2020 GNA included substation, feeder, and line section needs. The GNA identified distribution capacity, reliability (back-tie), voltage, and resiliency (microgrid) needs. PG&E's 2020 GNA load forecast includes future planned load transfers and switching operations that do not require a capacity project. Therefore, PG&E's 2020 GNA only includes identified grid needs that cannot be mitigated via distribution switching and load transfers that do not require a capacity project.

A single Planned Investment project may mitigate multiple grid needs that are identified in the GNA. Based on the 2020 GNA, PG&E identified 348 Planned Investments. After applying the technical and timing screens, PG&E identified 29 Candidate Deferral Opportunities.

The Candidate Deferral Opportunities and prioritization metrics will be presented to the DPAG in September 2020. Section 10.1 provides a proposed workplan and agenda for the DPAG meeting. After incorporating feedback from the DPAG and the IPE, PG&E will then submit the Final Candidate Deferral List by November 16, 2020.

1.4. Summary of PG&E's 2020 GNA Report

The following sections describe the study methodology and assumptions used to forecast and identify distribution grid needs in PG&E's 2020 GNA submittal.

1.5. PG&E's Distribution Resources Planning Horizon

To align with the circuit-level planning assumption requirements provided in D.18-02-004 Section 3.4.1.1, PG&E used a five-year forecast as the study horizon for identifying substation and feeder grid needs. For the 2020 GNA submittal, PG&E provides the assessment for the five-year planning horizon for substation and feeders for the years 2020 through 2024. PG&E identifies needs for line section and Volt/Var needs for a three-year period, and PG&E's 2020 GNA submittal therefore includes needs for line segments and Volt-Var for the years 2020 through 2022.[5] PG&E applies a 10-year planning horizon for Pre-Application Project needs (although no Pre-Application Projects were identified in PG&E's 2020 DDOR).

1.6. PG&E's Distribution System Load Forecast Assumptions

PG&E's load growth forecast begins 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 are deducted from the CEC system load growth forecast.[6] The resultant growth is distributed out by customer class (residential, industrial, commercial, and agricultural) and is then allocated to PG&E's distribution feeders using geospatial analysis.

PG&E uses the LoadSEER Geographic Information System ("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.

1.7. PG&E's Distribution System DER Growth Forecast Assumptions

Separate from load growth, PG&E has incorporated DER adoption into its distribution bank and feeder forecast assumptions. This is accomplished for residential photovoltaics ("PV"), retail non-residential PV, additional achievable PV, energy efficiency for different customer classes, electric vehicles ("EV"), energy storage charge

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

[6] Known new distribution loads are deducted from the systemwide forecast so that they can be added back in as local new load adjustments while maintaining consistency with the CEC forecast in aggregate.

and discharge, and Load Modifying Demand Response.[7] The starting point for developing these feeder level DER growth forecasts is 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 is 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 PV system adoption by zip code, the s-curve trending model, observed distributed generation penetration level, daily peak diversity factors, weather zones, and many other factors specific for each type of DER.[8] Consistent with the Assigned Commissioner's Ruling on the adoption of DERs Growth Scenarios issued August 9, 2017, and the assigned ALJ's Ruling on the Distribution Working Group Progress Report issued August 1, 2018, PG&E's Distribution System DER Growth Assumptions utilize:

- CED Update 2018 Mid Baseline Photovoltaic Generation
- CED Update 2018 Mid Baseline EVs
- CED Update 2018 Mid Baseline Energy Storage
- CED Update 2018 Mid Baseline LMDR
- CED Update 2018 Mid Baseline-Low Additional Achievable Energy Efficiency

1.8. PG&E's Load Transfers and Switching Assumptions for 2020 GNA

PG&E's 2020 GNA load forecast includes the impact of future planned load transfers and switching operations that do not require a capacity project. The planned load transfers and switching operations are used to balance the load between feeders and banks. 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.

PG&E's 2020 GNA only includes identified grid needs that require a capacity project to either directly mitigate a need or to enable distribution switching and load transfers that mitigate the need.

[7] Load Modifying Demand Response reshapes or reduces the net load curve as opposed to Supply Resource Demand Response which is integrated into the California Independent System Operator ("CAISO") energy markets.

[8] PG&E's DER Growth Forecast Assumptions are subject to updating and revision on an annual basis in accordance with distribution planning criteria and guidance provided by the Commission.

1.9. Grid Needs Assessment Scope

The scope of this report is as in D.18-02-004, with modifications to the GNA requirements according to the R.14-08-013 May 2019 ALJ Ruling[9] and the May 2020 ALJ Ruling.[10] PG&E's 2020 GNA includes substation/bank, feeder, and line section needs. As adopted in D.18-02-004, grid needs that are reported in this GNA submittal are limited to the forecast deficiencies associated with the four distribution services that DERs can provide as adopted in D.16-12-036, which are distribution capacity, voltage support, reliability (back-tie) and resiliency (micro-grid).

1.10. Customer Confidentiality and Critical Energy Infrastructure Information

To respect and protect customer privacy, PG&E follows aggregation and anonymization rules. Areas that do not meet these requirements are redacted in both the public version of the GNA Report and the public version of the DDOR report[11].

2. Mitigation of Grid Needs Identified in PG&E's 2020 GNA Report

PG&E's 2020 GNA Report is the basis for the Planned Investments and Candidate Deferral Opportunities included in this report. The GNA identified 582 needs across the PG&E service territory. These grid needs are either monitored[12] or mitigated by planned facility re-rates[13] or Planned Investments. A single Planned Investment may mitigate multiple grid needs that are identified in the GNA. Figure 2 summarizes how the grid needs identified in PG&E's 2020 GNA Report are used to identify Planned Investments and Candidate Deferral Opportunities in this report.

PG&E has presented all grid needs separately for the purpose of identifying planned investment and candidate deferral projects and applying the prioritization metrics to determine which projects to include in the DIDF RFO, as shown in Appendices A-C. In contrast to PG&E's 2019 DDOR, for those Planned Investments and Candidate Deferral Opportunities for which grid needs were identified that could be combined (e.g., a capacity need on a bank and on an interconnected feeder), PG&E has listed the needs separately in the 2020 DDOR.

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[9] May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, pp. A1-A2.

[10] May 11, 2020 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework—Filing And Process Requirements, Attachment A, pp. 89-98. Attachment A was subsequently revised on June 12, 2020.

[11] Redacted data is marked "cc", "customer confidential", or blacked out.

[12] For facilities that are forecasted to have a small overload for a short period of time, PG&E may monitor that forecasted overload as part of its engineering review in the annual distribution planning process rather than identify a planned transfer or planned investment.

[13] In rare instances equipment can be temporarily re-rated following testing and an operational history review to allow for project lead time.

3. Planned Investments

As described in Section 2, there are 439 distribution grid capacity, 100 reliability (back-tie), 43 voltage support, and 1 resiliency (micro-grid) needs identified in the 2020 GNA Report that are mitigated by substation, feeder, and line section Planned Investments. Appendix A shows the resulting Planned Investments.

3.1. Summary of Planned Investments

In total, there are 348 substation, feeder, and distribution line section Planned Investment that mitigate the 582 grid needs, because one Planned Investment may mitigate several grid needs. Table 3 summarizes the Planned Investments by project type and by Distribution Planning Region. The Planned Investments consist of substation projects (e.g., banks), feeders, and distribution line section projects (e.g., installation of switches). The Planned Investments are located throughout the Bay Area, Central Coast, Central Valley, and Northern Distribution Planning Regions.

Table 4 summarizes the Planned Investments by Distribution Service.[14] The majority of Planned Investments are for Distribution Capacity. Table 5 summarizes the Planned Investments by in-service date. 319 Planned Investments have an in-service date within the next three years, and 29 Planned Investments have an in-service date of 2023 or later. All line section Planned Investments have in-service dates within the next three years, because PG&E identifies needs for line section and volt/var needs for a three-year period.[15] Table 6 summarizes the Planned Investments by Locational Net Benefits Analysis ("LNBA") range. The methodology used in calculating the LNBA range is included in Section 6.2.

Table 3: Summary of Planned Investments by Distribution Planning Region and by Project Type

Distribution Planning Region	Project Type			Total
	Substation/Bank	Feeder	Distribution Line	
Bay Area	4	36	18	**58**
Central Coast	11	31	50	**92**
Central Valley	7	44	86	**137**
Northern	4	20	37	**61**

[14] Planned Investments that are meeting both a Distribution Capacity Need and a Voltage Support or Reliability (Back-Tie) Need are classified as Distribution Capacity for the purposes of this table.

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

Totals	26	131	191	348

Table 4: Summary of Planned Investments by Distribution Service

Distribution Service				Total
Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency	
275	43	29	1	348

Table 5: Summary of Planned Investments by In-Service Date

In-Service Date						Total
2020	2021	2022	2023	2024	2025	
74	168	77	22	5	2	348

Table 6: Summary of Planned Investments by LNBA Range

LNBA Range ($/kW-yr)						Total
$0	$0-$50	$50-$100	$100-$200	$200-$500	>$500	
0	231	37	23	9	5	305
LNBA Range ($/VPU-yr)						Total
$0	$0-$50k	$50k-$100k	$100k-$500k	$500k-$1M	>$1M	
0	0	3	30	4	6	43

3.2. DER Solutions Planned for IOU Ownership for Planned Investments

For PG&E's list of Planned Investments in PG&E's 2020 DDOR, PG&E does not have any DER solutions planned for IOU ownership or otherwise planned for procurement but not prioritized as Candidate Deferral Opportunities. No IOU-owned DER solutions are listed in the Planned Investment list because PG&E does not currently have any plans to own any DER solutions that would defer Planned Investments that met one of the four services as adopted in D.18 02-004. As stated in PG&E's Opening Comments to the 2020 DIDF Improvements Ruling,[16] PG&E would be open to an option to consider IOU ownership of DER solutions for Planned Investments, although not all candidate

[16] PG&E, Opening Comments of PG&E on Administrative Law Judge's Ruling on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process, filed January 17, 2020 , p. 19

deferral opportunities are suitable for consideration of IOU ownership. Whether they are suitable depends on the specific characteristics of the location (e.g., land, interconnection, etc.). To date, PG&E has not identified any Planned Investments suitable. To facilitate IOU ownership more broadly, re-examination of cost recovery and cost allocation would be necessary (see Section 10.2).

3.3. Planned Investments for DER-Driven Needs

Within the four distribution service types, PG&E has two Planned Investments for a DER driven Capacity need, Blackwell Bank 1 (DDOR178) and Huron Bank 1 (DDOR036). The Blackwell Bank 1 Planned Investment is a replacement of the Blackwell Bank 1 at the Blackwell Substation due to backflow caused by PV generation on the distribution grid. The Huron Bank 1 Planned Investment is a replacement of Huron Bank 1 with a 30 MVA transformer due to backflow cause by PV generation on the distribution grid. The Blackwell Bank 1 Planned Investments is a non-DER solution and is evaluated as a Candidate Deferral Opportunity in PG&E's 2020 DDOR to try to develop a DER solution to address the DER-driven needs. For the Huron Bank 1 Planned Investment, PG&E has solicited, contracted, and received approval for a non-DER solution to address the DER-driven needs.[17] The approved contingency plan for Huron Bank 1includes both DER solutions, if possible, and non-DER solutions.

3.4. Pre-Application and Post-Application Projects

There are neither Pre-Application Projects nor Post-Application Projects in PG&E's Planned Investment or Candidate Deferral Opportunities List for the 2020 DDOR. PG&E has no projects that are expected to require General Order 131-D compliance within the 10-year planning horizon and have sub-transmission or distribution components.

3.5. Status of Pre-Application and Post-Application Projects

PG&E currently has no Pre-Application Projects or Post-Application Projects with sub-transmission or distribution components within the 10-year forecast horizon.

In PG&E's 2019 DDOR, PG&E identified the distribution component of Estrella substation as a Post-Application Project and flagged the Forecast Certainty metric as a red flag given the late In-Service Date and corresponding uncertainty of the distribution component of the project. The distribution component of Estrella substation is no longer a Planned Investment for PG&E and thus is not included in PG&E's 2020 DDOR.

There is no Planned Investment at Estrella in the 2020 DDOR. The following changes have occurred since the 2019 DDOR:

[17] PG&E AL 5707-E

- There is no longer a forecasted capacity need at Templeton Bank 3 or at Paso Robles 1104 due to a decrease in the load forecast
- The capacity need at San Miguel Bank 1, San Miguel 1104, and Paso Robles 1107 will be met by the installation of a second bank at San Miguel (DDOR069), which will enable shifting load off San Miguel Bank 1 that resolves the forecasted overload. Distribution work will also be done in conjunction with the San Miguel Bank 2 installation in order to relieve the San Miguel 1104 overload.
- The capacity need at the Paso Robles Bank 1 and Paso Robles 1103 feeder will be met by the Heritage Ranch Reconductor (DDOR005) Planned Investment.

The transmission component of the Estrella project was approved in the CAISO 2013-2014 Transmission Planning Process (‘TPP”). PG&E received internal approval for the Advanced Authorization (“AA”) in May 2014. The original business case was approved by PG&E’s Board of Directors in February 2015. PG&E submitted a Permission to Construct (“PTC”) to the CPUC in January 2017. The proposed operational date in the submitted Proponents Environment Assessment (“PEA”) was May 2019. PG&E’s PTC application to the CPUC is currently under review.

4. Candidate Deferral Opportunities

As illustrated in Figure 1, the application of screens to the Planned Investments list (Appendix A) results in the identification of the Candidate Deferral Opportunities. D.18-02-004 requires the application of two screens: (1) technical screen and (2) timing screen. These two screens are further described in the following sections.

4.1. Technical Screen

The purpose of the Technical Screen is to identify the Distribution Services that DERs can provide to potentially defer a distribution project. The following definitions for the key distribution services that DERs can provide were adopted by D.16-12-036, *Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot*, issued December 22, 2016:

1 Distribution Capacity services are load-modifying or supply services that DERs 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.

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.

The technical screen was applied to the 2020 GNA, upon which this report is based. The needs and Planned Investments identified in PG&E's 2020 GNA and DDOR are limited to the four Distribution Services listed above. PG&E's 2020 GNA and DDOR include substation, feeder, and line section needs and Planned Investments.

4.2. Timing Screen

The purpose of the Timing Screen is to ensure that cost-effective DER solutions can be procured with sufficient time to fully deploy and begin commercial operation in advance of the forecast need date. For this year, PG&E is using the Competitive Solicitation Framework and a 2023 or later in-service date which is considered adequate time for DER developers to design, develop, market and deploy the DER solution as well as to minimize the cost of providing for a contingency plan should the DER procurement be unsuccessful. As shown in Table 5, 319 out of 348 projects were filtered out of the Planned Investments list using the timing screen.

4.3. Summary of Candidate Deferral Opportunities

The application of the timing and technical screens results in 29 Candidate Deferral Opportunities, as shown in Appendix B. Table 7 summarizes the Candidate Deferral Opportunities by Project Type and by Distribution Planning Region. Table 8 summarizes the Candidate Deferral Opportunities by Distribution Service. The majority of the Candidate Deferral Opportunities are Substation (Bank) and Feeder projects for Distribution Capacity service. Table 9 summarizes the Candidate Deferral Opportunities by In-Service Date. Due to the application of the timing screen, all Candidate Deferral Opportunities have an In-Service Date of 2023 or later. Table 10 summarizes the Candidate Deferral Opportunities by LNBA Range. The methodology used in calculating the LNBA range is included in Section 6.2.

Table 7: Summary of Candidate Deferral Opportunities by Project Type and Distribution Planning Region

Distribution Planning Region	Project Type			Total
	Substation/ Bank	Feeder	Distribution Line	
Bay Area	3	1	0	**4**
Central Coast	4	8	0	**12**
Central Valley	2	5	0	**7**
Northern	2	4	0	**6**

Distribution Planning Region	Project Type			Total
	Substation/ Bank	Feeder	Distribution Line	
Totals	**11**	**18**	**0**	**29**

Table 8: Summary of Candidate Deferral Opportunities by Distribution Service

Distribution Service				Total
Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency	
27	0	1	1	**29**

Table 9: Summary of Candidate Deferral Opportunities by In-Service Date

In-Service Date						Total
2020	2021	2022	2023	2024	2025	
0	0	0	22	5	2	**29**

Table 10: Summary of Candidate Deferral Opportunities by LNBA Range

LNBA Range ($/kW-yr)						Total
$0	$0-$50	$50-$100	$100-$200	$200-500	>$500	
0	17	7	4	1	0	**29**

5. DER Distribution Service Requirements

For each of the Candidate Deferral Opportunities listed in Appendix B, the DER distribution service requirements were defined for each grid need. Since each Candidate Deferral Opportunity may mitigate one or more grid needs, there may be one or more set of DER distribution service requirements for a given Candidate Deferral Opportunity. All the DER distribution service requirements for a given Candidate Deferral Opportunity are necessary to defer the investment.

The following annual DER service requirements were determined for each facility: months required, number of calls per year, estimated hours of need, and maximum duration (hours) per call of required DER distribution service.[18] To determine these requirements, PG&E evaluated the forecast peak load on each facility over the span of

[18] The DER service requirements are listed individually and are not combined for a Candidate Deferral Opportunity. PG&E will review with the DPAG Candidate Deferral Opportunities where the same operational requirements could meet several gird needs.

one year, using a 576-hour load profile[19] to determine when the overloads occur. The basis for the DER distribution service requirements was determined from the highest overload for the period from the in-service date until the end of the 10-year forecast horizon. Therefore, the distribution service requirement may be based on a later year than need included in the GNA which used a 5-year forecast as the study horizon for identifying grid needs. In contrast to PG&E's 2019 DDOR, the need included in the Planned Investments (Appendix A) will also be based on a 10-year forecast.[20] Using the 576-hour load profile, PG&E calculated the months, the number of days in the year, and the timespan and duration in which the electric facility is projected to overload or require the distribution service. Load transfers associated with new capital upgrade projects are excluded to ensure consistency between projects since some of these load transfers require part of the project to be completed.

For the Candidate Deferral Opportunities with reliability needs, PG&E identified operational requirements that include Real Time ("RT") dispatch capability (i.e., within 5 minutes[21]) in order for the DERs to defer the project. These reliability needs are driven by the need to reduce the impact of outages. Therefore, the need could arise at any time during the year. For Candidate Deferral Opportunities where there is an existing back-tie with a capacity constraint, the operational requirements entail RT dispatch of capacity to enable the remaining load to be transferred to the back-tie. For Candidate Deferral Opportunities where there is no existing back-tie (and where the Planned Investment is to install a new back-tie or mainline loop), the operational requirements entail RT dispatch of capacity and the ability to balance the load in an islanded state (i.e., operate as a microgrid). For PG&E's 2020 DDOR, PG&E identified two Candidate Deferral Opportunities (FMC 1102 and Lockeford Bank 1) that require RT dispatch capability. One of those Candidate Deferral Opportunities (Lockeford Bank 1), also requires the ability to balance load in an islanded state (i.e., operate as microgrid).

5.1. Operational Requirements

Utilities use standard equipment sizes that have been identified to provide cost-effective service to its customers. Generally, these standard equipment sizes reduce engineering design, equipment maintenance and spare equipment costs. When a system deficiency is mitigated, standard equipment sizes are used, which normally provides additional capacity to the system beyond the identified need. This additional capacity provides the ability to maintain loading and voltage requirements as well as the

[19] The 576-hour profile is generated in LoadSEER. This is organized by Month, Hour, and Weekday vs Weekend to determine DER distribution service requirements

[20] Planned Investments needs on line sections will be based a 3-year planning horizon

[21] Dispatch time may vary depending on location and availability of Supervisory Control and Data Acquisition (SCADA)

ability to transfer load for planned and emergency situations. This ability to operate the system on an on-going basis is often called operational flexibility.

Distribution planning projects typically add capacity in increments based on a standard bank or feeder size, rather than sizing exactly to the grid need. For example, PG&E's current standard distribution bank sizes are 16, 30, and 45 Megavolt-Ampere (MVA). PG&E's Calistoga Bank 1 Planned Investment proposes to replace the existing transformer banks with a 21 MVA rating with a 30 MVA transformer. The added transformer capability will meet the grid need even if there is uncertainty in the load forecast. In contrast, the total DER distribution service requirement listed for the Calistoga Candidate Deferral Opportunity is 4.2 MW. While the DER service requirement would potentially defer the Planned Investment, it does not provide any margin for load forecast uncertainty and does not allow for new customer load interconnections larger than the service requirement amount. If the grid need were to increase, the DER service requirement would no longer be sufficient, and the project would not be deferred. In addition, new load applications for service would likely be delayed while additional DERs were contracted or capacity projects were built. Alternatively, introducing a margin for the DER distribution service requirement, while increasing the likelihood of deferral, would increase the difficulty of procurement or ability to interconnect cost effectively. PG&E is not including any margin in the distribution service requirement in this DDOR. Therefore, even if resources are procured to meet the exact grid need, the project investment may still be required if the load forecast changes and the grid need is no longer met by the procured resources.

The identified Planned Investments also provide operational flexibility beyond meeting the identified grid need. For example, a transformer is available all hours, and load can be transferred to the bank from other feeders or banks as needed to provide additional operational flexibility. In contrast, the DER distribution service requirements only specify the hours of the grid need.

6. Project Costs

6.1. Unit Costs

The estimated cost accuracy of a project is based on the stage of project development. For projects in early stages of development, costs are estimated using either estimates of specific equipment and unit costs for work required, or historical costs from completed projects. As the project develops and scope details become defined, the estimated project costs are adjusted based upon the detailed scope of work. Differences between the unit costs shown in Appendix B and the costs in a GRC are generally due to:

- A GRC has a limited time window. Some projects are expected to have significant costs that occur outside of this window.

- A GRC includes escalated cost estimates. Unit costs are usually a fixed time value and are not escalated.

The unit cost uncertainty level corresponding to the American Association of Cost Engineers ("AACE") level for each Candidate Deferral Opportunity is included in the DDOR spreadsheet.

The unit costs applied to prioritization calculations include all deferable (unspent) costs, including regulatory and permitting costs and reflect the latest, most accurate information at the time of filing. The unit costs used for the calculation of the LNBA for Planned Investments that are screened out (and thus not prioritized as Candidate Deferral Opportunities) are based on the total unit cost rather than the deferrable (unspent costs). As these near term Planned Investments are often well underway in their design, procurement, and construction, the remaining deferral value would only be a fraction of the LNBA value.

6.2. Locational Net Benefits Analysis (LNBA)

The LNBA values were calculated using the Energy and Environmental Economics, Inc. ("E3") LNBA tool methodology[22] with the following inputs:

- Unit Cost: See section 6.1 for detailed description. Values are based on 2020 unit costs.
- Discount Rate: PG&E used a 7.12% discount rate. This discount rate is PG&E's after-tax weighted average cost of capital and reflects CPUC authorized cost of equity, cost of debt, and capital structure, as well as current tax rates.
- Revenue Requirement Multiplier: PG&E used a Present Value Revenue Requirement ("PVRR") multiplier of 134.8% for replacement of station equipment (substation and bank projects); 140.2% for replacement poles, towers and fixtures; and 138.4% for replacement overhead conductors and devices (primary feeder). PG&E used a PVRR multiplier (with Operations and Maintenance ("O&M") of 182.2% for new station equipment (substation and bank projects); 269.9% for new poles, towers and fixtures; and 279.0% for new overhead conductors and devices (primary feeder) that includes Operations and Maintenance (O&M) costs.
- Inflation: PG&E used a 2.5% inflation rate.
- O&M Factor: PG&E used an O&M factor of 2.52% for new station equipment (substation and bank projects); 7.0% for new poles, towers and fixtures; and 7.48% for new overhead conductors and devices (primary feeder). The O&M factor is used in the calculation or the PVRR. The PVRR (with O&M) includes this O&M factor and is used in calculating LNBA value for new projects.

[22] E3 LNBA Tool V2.11; https://e3.sharefile.com/share/view/sb2965cf362c48399

- Book Life: PG&E used a service live of 46 years for station equipment (substation and bank projects); 44 years for poles, towers and fixtures; and 46 years for new overhead conductors and devices (primary feeder).
- Deferral Time: PG&E used a deferral time frame from the in-service date of the Planned Investment until the end of the 10-year forecast horizon[23],except for line sections, in which case the largest forecast need identified over the forecast horizon of 3 years was used (i.e., peak MW shortfall within the 3-year forecast).
- Capacity (MW) of Deferral: PG&E calculated the Capacity (MW) need by taking the difference between the forecasted demand (MW) and the facility rating. A sum of the individual grid needs are used to calculate the LNBA value, assuming each grid need was independent.[24]
- Voltage Service of Deferral: PG&E used the worst-case voltage addressed by any single voltage correction project. A nominal voltage was assumed for each line section.

The approach used here is a preliminary methodology subject to change as LNBA is refined and as the DER requirements for this distribution service are refined with experience. The LNBA values in PG&E's 2020 DDOR include only the deferral value from the LNBA tool. For simplicity, 2020 Unit Costs are assumed. To derive the LNBA value, the deferral value output from the E3 tool was divided by the number of years of deferral (equivalent to the Deferral Time above) and the magnitude of need (MW, VPU).

6.3. Distribution Capital Per Customer Metric

Given that PG&E did not file a GRC during the 2020 DIDF cycle, PG&E does not have a distribution capital per customer metric included in its 2020 DDOR.

6.4. Payments Made to DER Projects

In accordance with Order D.18-02-004 paragraph 2.dd, PG&E is to provide itemized data payments made to DER projects versus the estimated traditional spending such deferral projects were able to avoid. To date, PG&E has not made any such payments, and so has no data to report in the 2020 DDOR.

6.5. Value Stacking Opportunities

The potential value stacking opportunities for each candidate deferral include participation in CAISO wholesale energy markets, the provision of Resource Adequacy, provision of ancillary services, management of customer bills (e.g. the reduction of

[23] May 11, 2020, Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework—Filing and Process Requirements, Attachment A (subsequently revised on June 12, 2020),, Item 6.

[24] For capacity projects not driven by a thermal capacity overload (e.g., new feeder projects), PG&E used the ratio of the need (e.g., amperage or customer counts) times the capacity of the asset.

customer demand charges, customer load shifting), and other revenue streams. As PG&E is only procuring the deferral service, each candidate deferral opportunity provides an opportunity for the DER developer to participate in CAISO markets and value stack other revenue streams. The revenue streams will depend on the DER solution (e.g., Behind the meter storage, In-Front of the Meter storage, Demand Response, etc,). PG&E does not have plans to spend capital for wholesale markets at the specific locations for these candidate deferral opportunities, so there is no additional investment deferral associated with the DER solutions at these locations.

7. Prioritization Metrics

In D.18-02-004, three metrics were adopted to characterize and help prioritize projects on the Candidate Deferral Opportunities shortlist. These metrics are: (a) Cost-Effectiveness, (b) Forecast Certainty, and (c) Market Assessment. Each IOU is to apply these metrics using its own approach provided the metrics support the deferral of any project that can be cost-effectively deferred by DERs.

PG&E has evaluated each of these metrics qualitatively, grouping the Candidate Deferral Opportunities into tiers based on their relative rankings. These qualitative rankings are based on quantitative data as well as engineering judgement by utility distribution planners where noted.

7.1. Cost Effectiveness Metric

Higher tiered projects under the Cost Effectiveness Metric are characterized by:

- High LNBA ($/kW-year)
- High Unit Cost of Traditional Mitigation
- High Converted LNBA per MWh of deferral ($/Megawatt-hour (MWh)-year)
- Judgement based on experience with pilots

The Cost Effectiveness Metric is intended to provide a relative indication of how likely DER resources can cost effectively defer a Planned Investment. The expected performance and operational requirements will be used to calculate the MWh of deferral. Judgement based on experience with pilots incorporates the lessons learned from PG&E's DRP Demonstration Projects C and D RFOs. For example, in these RFOs PG&E obtained learnings that baseload requirements may be difficult to obtain cost-effectively from DERs. The Independent Evaluator reported, "it may be best for PG&E to target circuit needs for future DRP RFOs that do not have a baseload need" due to high costs of DER solutions to meet baseload needs.25 For informational

[25] Public Independent Evaluator Report, Advice Letter 5259-E, Sedway Consulting, Inc., p. 7, March 26, 2018.

purposes, the LNBA/MWh-day26 value for each Candidate Deferral project is included in PG&E's 2020 workbooks. The MWH-day value is the maximum energy need on the day the peak demand was forecasted.

7.2. Forecast Certainty Metric

Higher tiered projects under the Forecast Certainty Metric[27] are characterized by:

- Available Supervisory Control and Data Acquisition (SCADA) data recordings
- Nearer term need (e.g., 2022 versus 2024)
- A lower forecast uncertainty rating from the questionnaire filled out by distribution engineers
- Judgement based on engineering knowledge of the area

The Forecast Certainty Metric is intended to give a relative indication of the certainty of the forecasted grid need. The availability of SCADA data provides more certainty on the forecast. The questionnaire filled out by distribution engineers includes questions on several factors that have significant influence on forecast uncertainty, based on lessons learned from prior DIDF cycles. For example, the age and condition of existing equipment at the facility, the potential for High Speed Electric Vehicle charging, and the dependence of area capacity on the specific location. Furthermore, engineering judgement from PG&E's distribution planners is also considered. The planners may consider the status of development milestones for large commercial, industrial and agricultural customers seeking new service or expansion of service. PG&E's distribution planners may also consider whether load forecast is particularly uncertain due to agriculture pumping load which is dependent on water availability and temperature/weather patterns.

7.3. Market Assessment Metric

Higher tiered projects under the Market Assessment Metric are characterized by:

- Only Day Ahead, rather than Real Time, operational requirements
- Low number of electric facilities experiencing grid needs in a specific location
- Shorter duration of needs
- Fewer calls needed per year
- Lower ratio of overload (lower penetration required)

[26] Calculated based on the MWh-day on the peak day only. This value is not equivalent to the deferral value per MWh-day of energy production.

[27] The Forecast Certainty metric is not applied to the prioritization ranking for Pre-Application projects. PG&E does not have any Pre-Application projects in its 2020 DDOR.

- Judgement based on experience with pilots

The Market Assessment Metric is intended to give a relative indication of how likely DER resources can be sourced that will successfully meet the DER distribution service requirements. For example, a location with multiple electric facilities experiencing grid needs may be more difficult to source DER solutions that are able to meet all the electric facility grid needs than a location with a single electric facility experiencing a grid need. In addition, a key learning from PG&E's DRP Demonstration Project C was that long duration needs with frequent calls (similar to baseload resources) are difficult to source. Operational requirements that require Real Time dispatch are less likely to be sourced via DERs versus operational requirements that only require Day Ahead dispatch. A high overload also indicates that a greater percentage of DER sourcing (i.e., a higher DER penetration) is needed.

7.4. Prioritization Metric Results

For ease of summarizing prioritization metric results, PG&E has developed a 4-tier system, where each tier represents PG&E's proposed priority ranking of those Candidate Deferral Opportunities likelihood of success for DER sourcing. The following table summarizes PG&E's proposed 4-tier system.

Table 11: PG&E's 4-Tier Prioritization System

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

All ranking of projects is relative. For example, a higher tiered project does not indicate that the project will be cost effective, have a certain forecast, or have a robust market[28]. It only indicates the ranking of the Candidate Deferral Opportunity relative to other Candidate Deferral Opportunities.

A red ranking indicates that there is a "red flag" associated with the Candidate Deferral Opportunity. Below are a few examples of the red flags, among others:

- Market Assessment: A market assessment red flag for a candidate deferral opportunity could be in regard to a lengthy DER service duration requirement,

[28] For example, green Candidate Deferral Opportunities are expected to be more cost effective than red Candidate Deferral Opportunities, but it does not indicate the Candidate Deferral Opportunity will be cost effective. Similarly, all the opportunities have some degree of forecast uncertainty

such as a continuous 24 hours or baseload need. PG&E has obtained learnings from prior pilots that baseload requirements may be difficult to obtain cost-effectively from DERs. The Independent Evaluator reported "it may be best for PG&E to target circuit needs for future DRP RFOs that do not have a baseload need", due to high costs of DER solutions to meet baseload needs.[29]

- Forecast Certainty: Absence of SCADA data, which increases the forecast uncertainty that the peak demand will materialize. Another example is if the Candidate Deferral Opportunity includes the replacement of old or in poor condition facilities, and thus might need to be replaced regardless of whether the need is deferred.
- Cost Effectiveness: Another example of a red flag for cost effectiveness is a LNBA value in the $0-$50/kW-year range. These red flags indicate that it is not likely a DER deferral solution can successfully be sourced at this time, although these grid needs would be re-evaluated in the following year's GNA and DDOR.

The individual prioritization assessment for the ranking of each Candidate Deferral Opportunity is included in Appendix C. The individual prioritization assessments are all combined qualitatively for each of the three metrics, and thus no weightings are applied.

[29] Public Independent Evaluator Report, Advice Letter 5259-E, Sedway Consulting, Inc., p. 7, March 26, 2018.

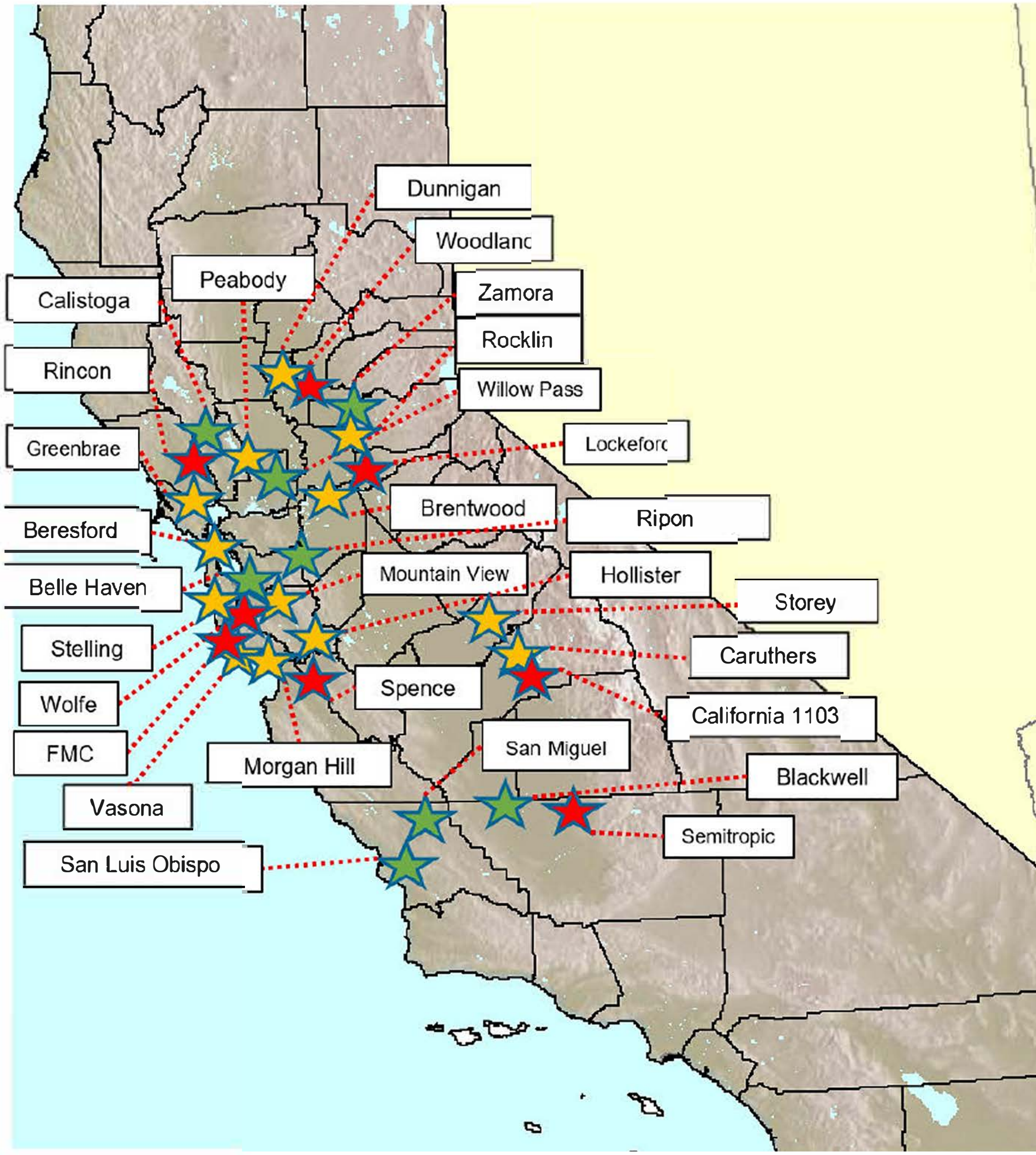
8. Candidate Deferral Opportunity Prioritization

PG&E's prioritization of its identified Candidate Deferral Opportunities is summarized in Table 12. Using PG&E's tier prioritization system, PG&E has identified approximately 170 MW of Candidate Deferral Opportunities for this DDOR, which are:

- Tier 1: Identified eight Candidate Deferral Opportunities totaling approximately 30 MW. Tier 1 Candidate Deferral Opportunities are relatively more likely to be deferrable.
- Tier 2: Identified thirteen Candidate Deferral Opportunities totaling approximately 40 MW. Tier 2 Candidate Deferral Opportunities have identified some red flags that indicate they are unlikely to be successfully deferred now. PG&E recommends not pursuing these Candidate Deferral Opportunities, but to closely monitor status and project conditions and re-evaluate for a future date.
- Tier 3: Identified eight Candidate Deferral Opportunities totaling approximately 100 MW. Tier 3 Candidate Deferral Opportunities have multiple major red flags that have been identified and indicate it is not likely a DER deferral solution can successfully be sourced.

Table 12: Preliminary Prioritization Metrics and Rankings of Candidate Deferral Opportunities

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)	Cost Effectiveness	Forecast Certainty	Market Assessment
1	Willow Pass Bank 1	2023	5.3			
	San Miguel Bank 2	2023	5.0			
	Calistoga Bank 1	2023	4.2			
	Ripon 1705	2024	3.7			
	Blackwell Bank 1	2023	[redacted]			
	Belle Haven Bank 4	2023	5.0			
	San Luis Obispo 1106	2023	[redacted]			
	Zamora 1108	2023	1.1			
2	Dunnigan Bank 1	2024	1.6			
	Beresford 401 Cut-Over	2023	1.5			
	Brentwood 2111 Line Work	2023	0.9			
	Hollister 2106 Line Work	2023	5.0			
	Rocklin 1104 and Rocklin 1101	2025	0.2			
	Caruthers 1104 Regulator	2023	0.7			
	Morgan Hill 2103	2023	6.6			
	Storey 1103	2023	3.2			
	Vasona 1109	2023	3.9			
	Peabody 2106 Outlet	2024	[redacted]			
	Stelling 1105	2023	4.6			
	Mountain View Bank 1	2023	5.7			
	Greenbrae Bank 2	2023	[redacted]			
3	Woodland 1105 Outlet	2025	1.3			
	Lockeford Bank 1	2024	14.8			
	Semitropic 1112 Line Work	2024	8.1			
	California 1103 & California 1111	2023	[redacted]			
	Wolfe 1111 & Wolfe 1112	2023	44.1			
	FMC 1102	2023	6.7			
	Rincon Bank 1	2023	8.0			
	Spence Bank 2	2023	[redacted]			



Tier	Candidate Deferral	In-Service Date	Deficiency (MW)
1	Willow Pass Bank 1	2023	5.3
	San Miguel Bank 2	2023	5.0
	Calistoga Bank 1	2023	4.2
	Ripon 1705	2024	3.7
	Blackwell Bank 1	2023	[redacted]
	Belle Haven Bank 4	2023	5.0
	San Luis Obispo 1106	2023	[redacted]
	Zamora 1108	2023	1.1
2	Dunnigan Bank 1	2024	1.6
	Beresford 401 Cut-Over	2023	1.5
	Brentwood 2111 Line Work	2023	0.9
	Hollister 2106 Line Work	2023	5.0
	Rocklin 1104 and Rocklin 1101	2025	0.2
	Caruthers 1104 Regulator	2023	0.7
	Morgan Hill 2103	2023	6.6
	Storey 1103	2023	3.2
	Vasona 1109	2023	3.9
	Peabody 2106 Outlet	2024	[redacted]
	Stelling 1105	2023	4.6
	Mountain View Bank 1	2023	5.7
	Greenbrae Bank 2	2023	[redacted]
3	Woodland 1105 Outlet	2025	1.3
	Lockeford Bank 1	2024	14.8
	Semitropic 1112 Line Work	2024	8.1
	California Ave 1103 & 1111	2023	[redacted]
	Wolfe 1111 & Wolfe 1112	2023	44.1
	FMC 1102	2023	6.7
	Rincon Bank 1	2023	8.0
	Spence Bank 2	2023	[redacted]

Figure 3: PG&E's 2020 Candidate Deferral Opportunity Locations

9. Contingency Plans

Electric distribution systems can change dynamically in terms of local area demand in response to agricultural water allocation and temperature sensitivity, economic drivers, and the unpredictability of large new customer load additions. When one of these drivers causes the load or near term forecast to exceed the local system capability, PG&E manages the load until capacity upgrades can be installed using field switching where possible, temporary re-rates on various pieces of equipment, and/or installation of temporary and mobile equipment.

Generally, these are the same contingency planning steps PG&E will use for contracted DER solutions that are not able to successfully mitigate the grid needs for the identified Candidate Deferral Opportunities. Specifically, PG&E has considered three different project stages where a DER solution can fail in being able to provide successful distribution services:

1. **DER Solicitation stage:** If no cost-effective or combination of cost-effective bids meet the grid need, or if there is a change in forecasted grid need date (e.g., accelerating the need for a solution sooner than originally planned), the contingency plan option is to either consider the deferral opportunity again in next year's DDOR[30] or proceed with the planned "wires" project if the start date for the project is prior to next year's distribution resources planning process.
2. **DER Implementation stage:** If the contracted DER solution fails to meet its implementation milestones and is not expected to achieve operations by the identified grid need date, or if there is a change in forecasted grid need date (e.g., accelerating the need for a solution sooner than originally planned), the contingency plan options available during this stage depends upon when during the DER implementation stage it becomes known the DER solution will be not be available to meet the identified grid need date. If it is early in the implementation stage, it may be possible for another cost-effective or combination of cost-effective bids to be considered[31]. If that is not the case, the contingency is to implement the planned wires project if possible. If it is later in the DER implementation stage, depending upon the loading and system conditions, a stop-gap wires solution including the various steps described above will be implemented.
3. **Commercial Operation stage:** If the contracted DER resource fails to meet performance requirements or simply fails while in service, PG&E will handle this situation in the same manner as with any other failed equipment. The immediate

[30] Where third-party DER procurement is unsuccessful, PG&E will consider full or partial IOU-ownership of a DER solution.

[31] Where third-party DER procurement is unsuccessful, PG&E will consider full or partial IOU-ownership of a DER solution.

emergency response includes distribution operations personnel implementing load transfers based on current loading profiles, installation of mobile generation, and/or a plan to interrupt power for local customers as a last resort. The contingency plan beyond the initial 24 hours would consider area loading, expected duration of the DER resource failure, potential transfers that may be available because of recent distribution infrastructure additions or improvements, re-rating of distribution facilities[32], including substation banks, and installation of temporary facilities such as a mobile transformer bank. [33]

It is important to note that new customer load applications for demand in the 2-5 MW range are not uncommon. PG&E cannot predict with absolute certainty where or when large new customer load will happen. For example, a high speed Electric Vehicle charging facility may result in a load application request between 5-10MW at a specific location. If an updated demand forecast is higher than what the DER solution can provide, PG&E would deploy the same contingency strategies identified previously in this section. PG&E also coordinates with customers in providing new service based on the size and timing of the load ramp up schedule.

As part of the ongoing evaluation and reform of the DIDF process, PG&E reports on the contingency spending for the most recent DIDF solicitations.[34] As of August 1, 2020, the contingency spend on Candidate Deferral Opportunities that PG&E received authorization to solicit is as follows:

- New Lammers Feeder: $1,690.54
- Huron Bank 1: $551,590.80
- Santa Nella: $345,143.66
- Calflax: $46,558.88
- Corcoran: $232.72
- FMC: $0

[32] The use of emergency ratings is unlikely to be a viable contingency plan for Candidate Deferral Opportunities with long duration needs due to the duration of the need exceeding the duration of the emergency rating.

[33] Where third-party DER procurement is unsuccessful, PG&E will consider full or partial IOU-ownership of a DER solution.

[34] May 7, 2019, Administrative Law Judge’s Ruling Modifying the Distribution Investment Deferral Framework Process, p. 13.

10. Recommendations and Next Steps

PG&E's recommendation is to pursue competitive solicitations for only the Tier 1 Candidate Deferral Opportunities (8 projects totaling approximately 30 MW) now as listed below:

- Willow Pass Bank 1
- San Miguel Bank 2
- Calistoga Bank 1
- Ripon 1705
- Blackwell Bank 1
- Belle Haven Bank 4
- San Luis Obispo 1106
- Zamora 1108

The FMC 1102 Candidate Deferral Opportunity is ranked as a Tier 3 Candidate Deferral Opportunity in PG&E's 2020 DDOR. FMC 1102 was ranked as Tier 2 in PG&E's 2019 DDOR, and PG&E requested and received authorization to solicit for DERs to try to defer FMC 1102. However, the forecasted load increased substantially since the 2019 DDOR filing, due to new pumping loads requesting interconnection in the area. Given the change in the Tiering of FMC 1102, PG&E recommends not proceeding with the solicitation for FMC 1102 and instead focusing on the higher Tiered Candidate Deferral Opportunities.

PG&E does not recommend pursuing competitive solicitations for Tiers 2 and 3 at this time due to their low likelihood of achieving a successful outcome. However, PG&E does recommend closely monitoring the status and conditions of the Tier 2 projects for re-evaluation and consideration of competitive solicitations at a later date. Therefore, these projects are not considered for competitive solicitation in this DDOR.

PG&E will present the Candidate Deferral Opportunities and preliminary prioritization metrics to the DPAG by September 18, 2020. The following section describes PG&E's proposed workplan for the DPAG.

10.1. Proposed Work Plan for the Distribution Planning Advisory Group

In accordance with D.18-02-004 ordering paragraphs 2.t, 2.u, and 2.v and the May 7, 2019, April 13, 2020, and May 11, 2020 ALJ Rulings Modifying the DIDF Process, PG&E will proceed with the below work plan for the DPAG meetings:

- Sept 10: The IPE circulates preliminary analysis of PG&E's GNA and DDOR
- Sept 14: Joint IOUs to host DPAG Primer Webinar
- Sept 16: PG&E to host its DPAG meeting. The following meeting agenda was noticed to the service list via electronic communication on July 30, 2020:
    - Planning assumptions and grid needs reported in the GNA

        - Review GNA data and discuss how the key GNA values were calculated
        - Overview of GNA results
        - What value determines whether a planned investment is necessary
    - Planned investments and candidate deferral opportunities reported in the DDOR
        - Overview of types of planned investments included in DDOR (and what types of distribution investments are in GRC but not included in DDOR)
        - Table that summarizes planned investments by type (in DDOR only) and capacity
    - Candidate deferral prioritization
        - Review the prioritization screens of the IOU's candidate deferral projects to discuss why investments were excluded
    - Underlying technical and operational requirements for the DER alternative.
        - Review criteria of potential projects for inclusion in solicitation to discuss whether DERs could fill the need at the cost of deferral
- Sept 25: Participants provide questions and comments to IOUs and IPE
- Oct 5-6: PG&E to host follow up DPAG meeting via Webinar
- Oct 25: IPE DPAG Reports issued

Based on feedback from the DPAG and the IPE, PG&E will then submit its Final Candidate Deferral List via an Advice Letter by November 16, 2020.

10.2. Future DIDF Reform

To consider future reforms to the DIDF process, PG&E provides the following recommendations for future DIDF reform:[35]

- Overall, PG&E views the DIDF as successfully providing information about PG&E's distribution planning process and identifying opportunities for deferral by DERs.
- PG&E's recommends that the timeframe for adding detailed historical PSPS outage data to the maps and datasets hosted on the DRP Data Portals should correspond to the timeframe submitted for PG&E's PSPS Data Visualization Portal Implementation Plan in the Microgrids Proceeding, to be submitted on September 17, 2020. Adding historical PSPS outage data will require new infrastructure, design, business processes, data sourcing, development, publishing work, and the allocation and training of resources. Preliminary analysis displays a possible timeline to provide some data related to this reform

[35] May 7, 2019, Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, p. 16.

by the end of 2021 at the earliest. PG&E recommends that the posting of this data be coordinated between the Microgrids and DRP Proceedings.

- PG&E did not identify any projects that may be feasible to defer by DER but do not meet the three-year timing screen in PG&E's 2020 DDOR. Lessons learned from prior DIDF cycles have indicated that DER developers already have difficulty meeting the In-Service Dates for Candidate Deferral Opportunities. Shortening the time to implement the DERs would only make the opportunities less feasible. Therefore, PG&E does not think it is feasible to implement a shorter timing screen in the 2020-2021 DIDF cycle. Instead, PG&E continues to recommend that the regulatory process for the DIDF be streamlined, to allow for more time between when the Candidate Deferral Opportunities are finalized and when bids are due from developers, as well as allowing for the shortening of the timing screen, as proposed in PG&E's comments for DIDF Improvements and prior DDOR reports.
- Forecasts of circuit segment and voltage and/or reactive power needs beyond three years would directly impact PG&E's Distribution Planning Process, necessitating the hiring and training of extra Distribution Engineers, the procurement of additional computational resources, and the procurement of additional software licenses. These resources needed would generally increase linearly with whatever additional years are modeled. For example, increasing the forecasting process for line segments from three to five years would increase costs of the distribution planning process by roughly two-thirds (~66%).
- Regarding equipment necessary to integrate DERs with the grid that could feasibly be owned by a third party, telemetry equipment owned by third parties could potentially replace required IOU owned reclosers or mini-RTUs for large DER installations 1MW and greater. PG&E is currently evaluating the technical feasibility of this option, with the goal of reducing customers' utility related costs to under $20k. Equipment required at a site-level include customer sited gateways for protocol translation and telecommunication equipment like modems. Based on current market forecasts, potentially hundreds of pieces of such equipment may be required over the next ten years. While there are benefits in potential reduced initial costs and customer ownership, there are serious concerns around cybersecurity, ongoing maintenance, and life cycle costs for customers that are still being evaluated.
- PG&E notes that many customers and aggregators already have their own equipment to integrate DERs with the grid for optimizing or controlling their own assets, with which the IOU equipment interacts. The challenges of third-party ownership of systems required to optimize beyond their local assets and at a grid-scale level include:
    - Sharing of customer data is required to create the underlying model, including customer load profiles, customer types, locations, etc.

- Higher costs for customers to create and maintain a utility level integration software.
  - The complexity of real-time model updates based on utility abnormal conditions and general utility maintenance and planning operations.
  - Potential Cybersecurity risks.
  - If equipment is used for electric distribution services/operations, the owner would be regulated directly by the CPUC as a public utility.
- PG&E's 2020 GNA and DDOR filings include a grid need ID, facility ID, and project ID numbering system. All project ID numbers are unique and directly link to specific projects in PG&E's GRC when such projects are specifically included in the GRC. Given PG&E's most recently GRC application was filed in 2018, not all projects are included in the prior GRC. Given that each IOU has differences in internal organizational and database systems for their GRC filings, and the need to align the GNA and DDOR with the individual GRC filings, slight differences in the numbering system may exist between IOUs. PG&E recommends that they work with the other IOUs to minimize these differences in future GNA and DDOR filings to the extent it does not impact the corresponding IOU GRC filings.
- PG&E did not include value stacking within its 2019 prioritization metrics. As PG&E only solicited for the deferral service, each candidate deferral opportunity provided an opportunity for the DER developer to value stack other revenue streams and was reflected in their bid price.
- The IPE recommended that cost effectiveness be considered as a threshold metric.[36] PG&E supports creating a cost effectiveness threshold at which Planned Investments would be screened out, as the DER solution would not be cost effective. One threshold could be to screen out all Planned Investments with a unit cost less than $500k, as the small deferral value is unlikely to warrant a solicitation. Another threshold could be to screen out all Planned Investments with a LNBA deferral value of less than $50/kW-year, as a DER solution is unlikely to be cost effective. PG&E notes that all Candidate Deferral Opportunities that have failed these thresholds in PG&E's 2018, 2019, and 2020 DDORs have not been recommended for solicitation as Candidate Deferral Opportunities. Adding a cost effectiveness threshold would instead screen out these Planned Investments, allowing for the DPAG to focus on the remaining Candidate Deferral Opportunities for prioritization.
- PG&E does not support GPI's recommendation about prioritization changing to a set of baseline/absolute threshold value and a ranking based on baseline/absolute threshold values that would carry over each year. Such an

[36] November 8, 2019 Administrative Law Judge's Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process, Attachment 2, Item J.

approach would obviate much of the need for the DPAG, as the input of DPAG members on the prioritization would no longer be needed. It would also hinder the ability to apply lessons learned in the prioritization of Candidate Deferral Opportunities.

- The following are conflicts between the DIDF and General Order 131-D and recommended solutions:
  - Risk of delay in implementation – The review of DER alternatives in both the DIDF and General Order 131-D may result in delays in implementation. For example, as described in Section 3.5, PG&E submitted a PG&E submitted a PTC to the CPUC in January 2017 and is awaiting a draft Environmental Impact Report (EIR). The completion of the licensing proceeding for the Estrella project, has been delayed in part because of the parallel review of the distribution need in the DDIF proceeding.
  - Risks sub-optimal outcomes for customer reliability – Delays in implementation may result in the need to install alternative equipment and implement contingency plans that are sub-optimal for customers' reliability. For example, the proposed In-Service Date for the Estrella project was May 2019. The Estrella project was proposed to meet a transmission reliability need with consideration of future distribution capacity needs and reliability and operational needs in the Paso Robles DPA. The need date for the capacity overloads at San Miguel Bank 1 and San Miguel 1104 are 2020 and 2022, respectively. Because the transmission components of the Estrella project are still being reviewed in GO-131D, any distribution work at Estrella would not be able to commence for several years. Due to these delays to the In-Service Date for Estrella, it is necessary to proceed with alternative Planned Investments in the area. The reliability issues at Cholame, Templeton remain and will require the use of contingency plans that may include mobile generation and load shedding.
  - Risks of Increased Costs – The review of projects in both the DDIF and General Order 131-D increases customer costs versus review in one proceeding. For example, the PTC proceeding for Estrella has resulted in CPUC costs of $1.6M to date, with an additional $0.5M expected. This is in addition to the costs PG&E has incurred to date in both proceedings, including responding to twelve Data Requests to date. These costs will ultimately be borne by the ratepayers; therefore, review in a single proceeding should facilitate a focused and efficient review efforts on behalf of the CPUC and the utilities.
  - Recommended Solution - The determination of whether a project or project component can be addressed by DERs should addressed in only one proceeding, rather than multiple proceedings:

        - If the distribution component of a Pre-Application Project is evaluated in the DIDF proceeding, the determination of whether such component is appropriately addressed by DERs should be made in the DIDF proceeding and that determination should be final as to any other proceeding in which the distribution component is being presented. For example, if the Pre-Application Project becomes a formal General Order 131-D license application, the DER determination made in the DIDF proceeding should be binding on the licensing proceeding. This means that a distribution component identified in the DIDF proceeding for which a competitive solicitation is held to seek DERs to address the distribution need should not be subjected to an Alternatives Analysis during the California Environmental Quality Act ("CEQA") review or administrative review in the licensing proceeding.
        - A distribution component identified in the DIDF proceeding as not appropriate for DERs and approved to not hold a competitive solicitation to seek DERs may also be subjected to an alternatives analysis during the CEQA review in the licensing proceeding if the CPUC determines that an Environmental Impact Report (EIR) is required. However, the alternatives analysis should be consistent with the conclusion reached in in the DIDF proceeding with respect to DERs. In other words, the alternatives analysis should summarize and refer to the rationale in the DIDF proceeding as the basis for rejecting DERs from detailed consideration and not carrying them forward as a feasible alternative in the EIR.
        - If a license application is filed for a project with a distribution component that has not been analyzed in the DIDF proceeding, the distribution component should be analyzed solely in the licensing proceeding from that point forward.
- PG&E has identified the following issues with encouraging IOU ownership bids in DIDF RFOs:
    - Recovery of costs under the Energy Resource Recovery Account (ERRA) discourages PG&E procurement of services beyond the distribution deferral value. The recovery of costs via ERRA for all services (other than the deferral value) creates fairness and equity concerns, because the procurement of the DER services is fundamentally being done to address grid needs, not to address a bundled customer need. Instead, all costs should be recorded in a non-bypassable procurement account (e.g., the Distributed Energy Resources Distribution Deferral Account (DERDDA)) in a manner analogous to the cost recovery approved for the Llagas DER project. In contrast to cost recovery via ERRA, this would allow DERs to realize the value from all distribution customers rather than just bundled

customers. Without such a modification, PG&E's solicitations for IOU ownership would be constrained to the consideration of the deferral value of the DER solution offered.

  - The 2020-2021 DIDF RFO may be delayed because there are significant time and resource requirements in creating an RFO that encourages IOU-ownership DER bids. The cost and labor associated with creating a DIDF solicitation that encourages an IOU-ownership bid will be significant. Encouraging IOU ownership bids requires PG&E to create very detailed technical specifications as to resource eligibility (e.g., equipment that PG&E would own and operate over its lifetime, how the resource be constructed, and what safety and operating standards are required). This is substantially different and more complex than the procurement of third party DER services because PG&E would be responsible for owning, maintaining and operating the resource for several years. In addition, it may not be desirable for PG&E to own, maintain, and operate certain types of projects, for example customer-sited DERs (e.g., pool pumps or improved lighting at a customer site). Moreover, this work requires organizational groups or individuals within PG&E to ensure that there is no transfer of sensitive information (e.g., bidder data, valuation data, etc.), the creation of more complex bidding materials and contract language that considers multiple forms of ownership, and a prolonged evaluation and negotiation phase for any IOU ownership bids. Therefore, PG&E anticipates that it would need to hire and train incremental resources with specific procurement expertise in order to be able to encourage IOU ownership bids in the 2020-2021 DIDF RFO. As PG&E would need to vet both the technology and the project's ability to meet the necessary technical requirements, PG&E anticipates it would take an additional 6 months to launch the RFO and negotiate, execute, and file for approval in order to encourage IOU ownership bids for at least one Candidate Deferral Opportunity in the 2020-2021 DIDF RFO.

- PG&E will consider SCE's day-ahead dispatch requirement in a supplement to the GNA/DDOR report by November 16, 2020.
- PG&E shall provide to Energy Division a report organized by deferral opportunity that contains itemized data on any payments made to contracted deferral projects and all spending on contingency plans for each deferral opportunity by November 16, 2020. The reporting shall include any modifications or additional details required by Energy Division. The reporting shall include all candidate deferral projects launched in a DIDF RFO since 2018.
- PG&E draft text on Self-Generation Incentive Program ("SGIP"), Net Energy Metering ("NEM"), and Energy Efficiency incrementality for the 2020-2021 RFO will be based on PG&E's 2019 RFO Protocol and will include PG&E's February 7, 2020 clarifying text as follows:

- Projects receiving SGIP funding will be considered fully incremental, as long as the project commits to meeting the dispatch requirements described in the protocol and pursuant to the Technology Neutral Pro Forma (“TNPF”) agreement. As noted in the RFO protocol, SGIP projects that provide an incremental service will be considered fully incremental. SGIP projects do not currently have an obligation to respond to utility dispatch signals. As a result, committing SGIP capacity to meet the dispatch requirements would be considered an incremental service above and beyond what is compensated via SGIP. Any SGIP-incentivized storage project that provides the services solicited in this RFO would be considered wholly incremental. The project will receive the full IOU payment for the services procured under this RFO irrespective of any additional SGIP incentives payments it may receive. SGIP projects must still meet all applicable SGIP requirements in order to obtain SGIP incentives, and bidders should direct questions specifically about SGIP eligibility to their respective program manager.
- Projects already compensated through NEM will be considered fully incremental if they make a material enhancement in order to provide services solicited in this RFO (e.g., the addition of storage that commits to meeting the dispatch requirements described in the protocol and pursuant to the TNPF) would be considered wholly incremental. NEM projects without material enhancement are not considered incremental.
- New energy efficiency projects can demonstrate incrementality via two methods as described in this RFO:
  - Participants can choose a program specific review, whereby Participants describe their proposed energy efficiency measures and targeted market segments in the RFO Section on Resource Double Payment/Double Counting and demonstrate that the projects do not overlap with PG&E’s existing programs. If a proposed program does overlap with PG&E’s existing EE programs, PG&E will estimate the degree of overlap. Program incrementality using this method could range from 0% to 100%.
  - Alternatively, Participants can opt to use a pre-specified overlap method which does not require Participants explicitly demonstrate incrementality. With this approach, Proposed programs are automatically assumed 80% incremental and their contribution to the DIDF MW target is discounted by 20%. Assuming PG&E has a 1 MW DIDF target, a project using the haircut method would need to deliver approximately 1.2 MW in order to meet the DIDF need.
- Projects already in PG&E’s Energy Efficiency program portfolio would NOT be considered incremental by definition and would need to make a material enhancement for the purpose of providing services solicited in

this RFO that is clearly demonstrable above and beyond the scope of the original program in order to be considered wholly incremental. As described in the RFO protocol, offers for energy efficiency projects can either be evaluated for incrementality through a project-specific review or based on a pre-specified overlap factor.

- PG&E continues to recommend that LNBA calculations only be required for the Candidate Deferral Opportunities (rather than for all Planned Investments), as the purpose of this information is to evaluate the feasibility of DER deferral and it is a significant undertaking to provide this information for all Planned Investments. Furthermore, as explained in Section 6.2, the LNBA values for Planned Investments that are not Candidate Deferral Opportunities are not indicative of the deferral value. The unit costs used for these Planned Investments are based on the total unit cost rather the deferrable (unspent costs). Therefore, the LNBA value for these Planned Investments is not representative of the deferral value and thus serves no purpose.
- PG&E continues to recommend that the regulatory process for the DIDF be streamlined, to allow for more time between when the Candidate Deferral Opportunities are finalized and when bids are due from developers, as well as allowing for the shortening of the timing screen, as proposed in PG&E's prior comments for DIDF Improvements.[37]
- PG&E continues to recommend that line sections be excluded from future DIDF cycles, as assessing line section needs and documenting the line section Planned Investments requires extensive effort, while few, if any, are likely to be viable Candidate Deferral Opportunities due to the near-term identification of the need, the uncertainty of the long term forecast for line sections, the relatively smaller amount of customers for which to potentially market DERs, and the relatively smaller cost of the traditional mitigation.

[37] PG&E Opening Comments on ALJ Ruling Seeking to Improve the Distribution Investment Deferral Framework, March 2019, pp. 3-5.

Appendix A Planned Investments

PDF attached separately

Appendix B Candidate Deferral Opportunities

PDF attached separately

Appendix C Prioritization Metric Workbook

Workbook PDF attached separately

Appendix D LNBA Workbooks

Workbook PDF attached separately