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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)	
Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005
And Related Matters.	Application 15-07-007 Application 15-07-008

ADMINISTRATIVE LAW JUDGE'S RULING MODIFYING THE DISTRIBUTION INVESTMENT DEFERRAL FRAMEWORK PROCESS

Summary

This Ruling modifies the Distribution Investment Deferral Framework process and establishes requirements for inclusion in the Grid Needs Assessment and the Distribution Deferral Opportunity Report.

1. Background

In Decision (D.) 18-02-004, the Commission adopted the Distribution Investment Deferral Framework (DIDF). Building upon the Competitive Solicitation Framework developed in the companion Integration of Distributed Energy Resources (IDER) proceeding,[1] the DIDF established an ongoing annual process to identify, review, and select opportunities for third party-owned distributed energy resources (DERs) to defer or avoid traditional capital investments in the investor-owned utilities' (IOUs) distribution systems. D.18-02-004 ordered the IOUs to implement the DIDF as an annual planning cycle that would result in the selection of distribution upgrades for deferral through the competitive solicitation of DERs.

The DIDF framework was implemented for the first time in 2018 with the expectation that it would be evaluated and revised after each cycle to streamline and improve the process. To that end, the assigned Administrative Law Judge (ALJ) issued a *Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework Process* on February 29, 2019 (*February 29, 2019 Ruling*), and invited party comments on possible changes and improvements to the 2019 cycle of DIDF. In addition, parties served comments to the Grid Needs Assessment which was filed by the IOUs on June 1, 2018. Parties also provided input on the DIDF process throughout the first DIDF cycle and staff have gained experience with implementing the DIDF framework.

Six parties provided comments in response to the February 25, 2019 ALJ Ruling: California Energy Storage Alliance (CESA), California Public Advocates Office (Public Advocates), Pacific Gas & Electric (PG&E), San Diego Gas &

[1] Rulemaking (R.) 14-10-003.

Electric (SDG&E) Vote Solar/Solar Energy Industries Alliance (Vote Solar/SEIA) and Southern California Edison (SCE). Based on party comments on the *Ruling* questions as well as the other sources of comments and input mentioned above, I will make the following modifications to the DIDF Framework.

2. Schedule and Content of DIDF Filings

The *February 25, 2019 Ruling* requested comment on what modifications to Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR) would improve the DIDF process.

There was broad agreement among parties, with the exception of Public Advocates, that the GNA and DDOR should be consolidated into a single filing. August 15 was the earliest date that the IOUs agreed would be feasible to submit a consolidated GNA/DDOR filing. Public Advocates asserts that the GNA should be maintained as a separate filing that should be submitted in June in order to allow time for Public Advocates to perform their analysis of GNA data in relation to the General Rate Case (GRC) filings each year. However, since GRC Applications are generally filed in September, I don't find that an August 15 GNA filing will limit Public Advocates' ability to evaluate the data within the GRC, which is made available later. I also find that it is preferable that the GNA data be consistent with information provided in the DDOR.

Public Advocates provided a list of recommendations of additional requirements for the GNA, which references PG&E's 2018 GNA as an example of the appropriate level of detail to include in the GNA. While I am in general agreement with Public Advocates that a narrative and more detailed data would be helpful, there needs to be a balance between greater detail and creating requirements that are feasible to produce on an annual basis. I have modified this list of requirements for the GNA to include as Attachment A of this *Ruling*.

Due to the new requirements to include a narrative explanation of the forecasts, the *Advice Letter required by the Administrative Law Judge's Ruling on the Distribution Working Group Progress Report issued* on August 1, 2018 will no longer be necessary.

The IOUs disagreed with Public Advocates' request for additional information in the GNA, stating that the information is out of scope of the DIDF process, and the sole purpose of the GNA is to inform DIDF. I disagree. D.18-02-004 adopted staff's proposal for a "GNA submission that would serve as the main driver of the [Distribution Resources Plan] DRP process, wherein the IOUs would report on the grid needs and planned investments that result from the annual planning process to inform both the DIDF and the Grid Modernization Investment Framework."[2] As the Grid Modernization Framework is a component of the GRC, I find that the GNA is a valuable tool for providing transparency of distribution planning costs contained in GRCs and can also inform the calculations of avoided transmission and distribution costs associated with DERs, which is an important objective of the DRP. Further, D.18-02-004 states that the GNA/DDOR "…presents a significant opportunity to inform the triennial General Rate Case. For instance, in an IOU's GRC filing year, the forecasts, grid needs, and planned projects presented in the GNA and DDOR could contribute to the baseline for that year's budget request." As such, the GNA should be robust enough to serve these purposes.

Consistent with requirements established in D.18-02-004, I affirm that future GNA filings should describe all types of grid needs and the processes

[2] D.18-02-004 at 32.

used to determine the need. This includes all grid needs subject to CPUC jurisdiction, including all substation and sub-transmission system needs for which the deferable project would be requested. In their 2018 GNA, PG&E provided forecast and facility loading data for all feeders on their distribution system. This data is necessary to provide a comprehensive analysis of the distribution system impacts of DERs. I acknowledge that this expands the scope of data required in the GNA, so I will limit this requirement to be included in 2019 GNA, and review whether it continues to be necessary on an ongoing basis.

As required by D.18-02-004, GNA datasets should be provided in machine-readable spreadsheets and submitted in electronic format with formal GNA filings. The IOUs should explain any discrepancies between the GNA data and corresponding online maps. Additionally, the GNA should include the entire list of circuits on the distribution system, with forecasted demand, DER growth, and percent loading for each individual circuit. Additionally the GNA should contain the Distribution per Customer Metric as ordered by D.18-02-004.

SEIA stated that the data and methodology used in the GNA and the DDOR filings should be consistent across all three IOUs. The Commission approved the IOUs' data formats via Resolution E-4944 issued on August 24, 2019, which varied by IOU. I recognize the long-term usefulness of consistent datasets for analytic purposes and acknowledge that the IOUs' process for producing the GNA data is complex and requires significant lead time to produce specific outputs. Thus, I expect that the IOUs will work towards a common, comparable dataset by 2020, and that the IOUs identify what changes are necessary to achieve this objective in their 2019 DDOR report.

SCE raised the issue that certain deficiencies are measured as megawatts and others as megavolt ampere, and that line segment and volt/var requirements are only identified for a two- to three-year period. It is reasonable that the IOUs include needs for the time horizon for which they are forecast but should identify and explain these needs in the written narrative.

SEIA/Vote Solar stated that GNA/DDOR should provide more details on how DERs can meet grid needs, specifically, what the caused the distribution need. The cause of the distribution need is necessary information, but not for the entire list of distribution upgrades. This information will only be required for candidate distribution deferral projects contained in the DDOR.

Finally, the Commission and California Independent System Operator (CAISO) have expressed their commitment to identify and consider non-wire alternatives across the entire transmission and distribution system. CAISO has integrated non-wires alternatives into their Transmission Planning Process.[3] The Commission recently incorporated consideration of non-wires alternatives into the review of a proposed new transmission projects, the SCE Application (Application 15-12-007) for a Permit to Construct Circle City Substation and Mira Loma-Jefferson Sub-transmission Line Project. Public Advocates in their comments on DIDF requested that sub-transmission projects should be included in the GNA/DDOR. I clarify here that any utility planning project – for distribution or transmission – that is not separately undergoing an analysis as

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

part of the CAISO Transmission Planning Process (TPP) should be included in the GNA/DDOR. I decline to specify a voltage level cutoff for the planning that is subject to the GNA/DDOR because I recognize that there is variation across the utilities for what voltage levels are considered networked transmission subject to the CAISO's TPP tariff, and instead I state that the main point of delineation is whether the planning is subject to CAISO or CPUC jurisdiction.

I direct the IOUs to work with Energy Division to determine any adjustments that need to be made to incorporate transmission projects into the GNA/DDOR. If substantial changes are necessary for the transmission component of the GNA/DDOR, any or all of the IOUs shall submit a Tier 2 Advice Letter within 21 days of this ruling so stating why substantial changes are absolutely necessary ahead of the GNA/DDOR filing on August 15, 2019. Even if there are changes filed via Advice Letter, the distribution component of the GNA/DDOR should proceed as directed in this ruling regardless of any filed and possibly pending Advice Letter.

GNA/DDOR requirements are listed in Attachment A.

3. Distribution Planning Advisory Group (DPAG) Schedule and Agenda

The *February 25, 2019 Ruling* requested comments on what changes, if any, should be made to the structure and agenda of the DPAG in order to efficiently and effectively review the IOUs' candidate deferral projects.

There was broad agreement among parties that the DPAG meeting structure and agenda should be changed and consolidated to reduce the administrative burden and time intensity associated with meeting attendance as well as to focus the meeting agenda on the most salient topics. Only Public Advocates disagreed, stating that structure of DPAG should not be changed. I find that the DPAG process would be more effective if the schedule and agenda were established before the DDOR is issued, and the agenda is streamlined.

Going forward, Energy Division will develop the agenda and issue the final agenda for the DPAG meetings to the service list. Energy Division may also modify the DPAG schedule established here as needed with notice to the service list. I reaffirm that the DPAG should maintain its original scope, and should remain focused on the agenda topics identified in D.18-02-004: (1) planning assumptions and grid needs reported in the GNA; (2) planned investments and candidate deferral opportunities reported in the DDOR; (3) candidate deferral prioritization; and (4) underlying technical and operational requirements for the DER alternative. Solicitation requirements will be addressed through the reform of the Competitive Solicitation Framework in R.14-10-003 (the IDER Proceeding).

Following the submission of the GNA/DDOR, the Independent Professional Engineer (IPE) will have 21 days to conduct a preliminary analysis to present at the DPAG meetings, which may raise additional questions for the parties and/or the IOUs. IOUs' DPAG meetings will occur over consecutive days, as needed. There will be an introductory session provided by the IOUs for new DPAG participants to provide an overview of the DIDF process, explain the GNA, and how they identify and prioritize deferral projects, along with the factors that determine which projects should be selected for deferral. I expect the IOUs to work together to present this "101 primer," and attendance for non-IOU DPAG participants is optional. The IOUs shall coordinate with Energy Division to plan the DPAG meetings, in order to streamline presentations. Following the initial round of DPAG presentations and discussions, parties will have an opportunity to submit additional comments and questions to the IPE and the

IOUs. There will be a follow-up webinar in order to address these comments and questions. The DPAG process will be established as follows:

DPAG Schedule

Activity	Date (on or before)
IOUs submit GNA/DDOR	August 15
IPE circulates preliminary analysis	September 10
DPAG Meetings	September 16-20
Participants provide questions and comments to IOUs and IPE	September 23
Follow up meeting via webinar	October 7-8
IPE Final Report	October 21
DIDF Advice Letters Submitted	November 15
Launch RFO for DERs	Within 30 Days of DIDF AL Approval

4. Data Confidentiality

The *February 25, 2019 Ruling* requested comment on whether any of the data categories that the IOUs marked as confidential are overly redacted and should instead be public. For the 2018 DIDF process, the IOUs submitted a confidential version of the GNA and DDOR and required a Non-Disclosure Agreement (NDA) for participation in the DPAG, claiming that is necessary to maintain the confidentiality of data that the IOUs deem as market sensitive or as critical infrastructure.

The IOUs claims for confidential treatment and redaction of distribution planning data were first addressed the *ALJ Ruling addressing Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas& Electric Company's Claims for Confidential Treatment and Redaction of Distribution System*

Planning Data Ordered by Decisions 17-09-026 AND 18-02-04, issued on July 24, 2018 (*July 24, 2018 Ruling*), and adopted criteria for identifying data that should be classified as critical electrical infrastructure information for redaction purposes and directed the IOUs to show how data it wishes to redact would fit within that criteria. The *July 24, 2018 Ruling* rejected the attempt to redact information that the IOUs deemed market sensitive, determining that there was an inadequate showing that the information sought to be redacted meets the definition of trade secrets set forth in Government Code § 6254.7(d).[4] Nor was there any showing that the information fits within the definition of a trade secret set forth in Civil Code § 3426.1(d).[5]

The *ALJ's Ruling Resolving Confidentiality Claims Raised by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company* issued on December 17, 2018 (*December 17, 2018 Ruling*) found that the IOUs failed to carry their burden of proving that the information that they wished to redact from their soon to made public online maps and/or make subject to a non-disclosure agreement, met the definition of Critical Electrical Infrastructure Information that should be protected from public disclosure on confidentiality (*i.e.* physical or cybersecurity) grounds. The *December 17, 2018*

[4] "Trade secrets," as used in this section, may include, but are not limited to, any formula, plan, pattern, process, tool, mechanism, compound, procedure, production data, or compilation of information which is not patented, which is known only to certain individuals within a commercial concern who are using it to fabricate, produce, or compound an article of trade or a service having commercial value and which gives its user an opportunity to obtain a business advantage over competitors who do not know or use it.

[5] Trade secret means information, including a formula, pattern, compilation, program, device, method, technique, or process, that: (1) Derives independent economic value, actual or potential, from not being generally known to the public or to other persons who can obtain economic value from its disclosure or use; and (2) Is the subject of efforts that are reasonable under the circumstances to maintain its secrecy.

Ruling ordered that by December 28, 2018, PG&E, SCE, and SDG&E make available online, through their respective DRP portals, the Integration Capacity Analysis and Locational Net Benefits Analysis (LNBA) maps and underlying data, as well as the GNA and DDOR data required by D.17-09-026, Ordering Paragraphs 5 and 6, and D.18-12-004, Ordering Paragraph 2.e.

In summary, the ALJ's Rulings found that there was no information within the GNA or DDOR that merited confidential treatment, and therefore by extension I find that an NDA is unnecessary for DPAG participation and for viewing the GNA and DDOR reports.

In the comments on the *February 25, 2019 Ruling*, CESA argued that specific LNBA values, rather than LNBA ranges, should be provided in future DIDF cycles, arguing that wide range of value was not useful in determining the viability of a potential deferral project. I agree and instruct the IOUs to provide specific values in future DDOR filings.

5. Prioritization and Cost Effectiveness Metrics

The *February 25, 2019 Ruling* requested comment on the information needed to determine if candidate deferral projects provide a reasonable basis for prioritization and evaluation of DER alternatives based on the cost-effectiveness metric.

The IOUs argue that the prioritization criteria as originally described in D.18-02-004 continues to be appropriate. In their view, there should not be any changes as the Decision afforded the IOUs a certain degree of flexibility to apply the methodologies in a manner that is most appropriate for their service territory characteristics. CESA and SEIA argue that the cost effectiveness evaluation should be applied consistently across the IOUs, however, there was disagreement as to which IOU's cost effectiveness metric was superior.

Public Advocates states that PG&E had most robust and detailed criteria for cost effectiveness. Meanwhile CESA stated it favors SCE's cost-effectiveness methodology because it has a clearer $/MWh value to assess against DER solutions and determines this value on a 10-year need, which lends itself to longer term deferral contracts, which therefore supports securing financing for DER projects

I recognize the need to improve the consistency of the metrics, to allow DER developer to compare the relative viability of potential projects. However, it is not clear currently whether it is appropriate to entirely replace the LNBA value with the $/MWh value to prioritize projects. I therefore direct the IOUs to continue to provide the LNBA value for the candidate deferral projects, and to provide $/MWh. I direct the IOUs to present a clear explanation on which factor(s) are used to establish the tier levels of prioritization. I also direct the IOUs to determine cost-effectiveness of deferral opportunities on a 10-year need basis for consistency and to provide more long-term certainty for DER deferral opportunities. What this means in practice is the deferral period should always match the length of the need period.

6. Contingency Plans and Changes to Planning Data and Projects

The *February 25, 2019 Ruling* requested comment on whether it was possible to design the DIDF process so that the selection of deferral projects are vetted and "litigated" once and not subject to unpredictable changes.

All parties identified the execution of a contract as the point in which a distribution deferral project should more forward as contracted, unless need has increased to the degree that that DER project would not be able to be modified to meet the need. SEIA/Vote Solar clarified that once the IOU has submitted an advice letter seeking approval of the contract, it should not easily be allowed to make a change. I find this to be a reasonable threshold. However, if the IOUs need to make any changes to the DIDF solicitations after the November 15 DIDF Advice Letters have been approved, the IOUs shall submit an additional Tier 2 Advice Letter to explain the cause of the change and the modified operational requirements, if applicable.

SCE raised the concern that spending on contingency planning is unavoidable, including design work, equipment, permitting, and other preconstruction activities should not be suspended while the projects are being bid out for distribution deferral. The IOUs should be able to record such design and engineering work in the Distribution Deferral Balancing Account (DDBA). Projects that were explicitly approved in the GRC should be booked to DDBA as the difference between the DER contract payment and the revenue requirement that was approved for the project. In addition, SCE proposes that the estimated design and engineering costs be deducted from the total capital cost estimate before calculating the deferral benefit that the Net Present Value (NPV) of the non-wires alternatives are benchmarked against.

I recognize the need for the IOUs to incur costs on contingency planning, however, I am concerned that the deduction of any contingency spending from the deferral benefit as part of the NPV calculation would motivate the IOUs to frontload their contingency spending and make distribution deferral unviable. Instead, I direct the IOUs to report on the contingency spending for the most recent solicitations as part of the DDOR, as part of the ongoing evaluation and reform of the DIDF process.

7. Scope and Role of IPE

The *February 25, 2019 Ruling* requested comment on what is the appropriate scope of work and responsibilities for the IPE. The IOUs stated that the IPE scope of work and responsibilities in the 2018 DIDF cycle were appropriate and did not need to change. Public Advocates did not find it the best use of the IPE's time to summarize the IOUs filings and instead believes the IPE should focus more on engineering analysis of the relevant GNA and DDOR information and findings. Public Advocates, CESA and SEIA recommended that the IPE should be contracted by and directly report to Energy Division. While I agree with the intervenor parties that independence of IPE is necessary, the limitations in state contracting continues to necessitate that the IOUs select and administer the IPE contract. However, the IPE shall report directly to Energy Division to prepare its deliverables and conduct its analysis.

The role of the IPE is to verify the assumptions and estimates that are reported in the GNA/DDOR and to provide an engineering assessment to verify that all grid needs and all distribution upgrades that can be considered for deferral have been included. To do so, the IPE should explain the data gathered and how the information provided by IOUs was verified or validated. For information that could not be verified, explain what the information gaps are. Specifically, the IPE's Scope of Work should review:

- DER forecast disaggregation
- Forecasted grid needs that reflects all grid needs and all distribution upgrades that can be considered for deferral
- Timing of projects
- The cost estimates for the deferral projects so that they accurately reflect the total distribution project cost

- Application of screening metrics and processes to the deferral projects to ensure that screening is consistent with the approved methodology
- DER operational requirements for selected projects

The IPE report should also include a brief summary of issues raised by DPAG members and IOU responses, which may be collected through written comment, and recommendations on whether any distribution deferral projects should be added, removed or modified. The report shall include all data requests submitted to the IOUs and responses as attachments to the report.

There will be a 21-day gap following the submission of the GNA/DDOR to enable the IPE to provide preliminary analysis at DPAG meetings. This will be an opportunity for the IPE to present on their method for reviewing the IOUs' GNA/DDOR in terms of what question and types of information that they are gathering from the IOUs, and for the participants to add their questions. The IPE does not need to present findings or conclusions at this time, but rather to discuss how they will verify the information in the GNA/DDOR.

8. Data Requirements for Solicitations

The *February 25, 2019 Ruling* requested comment from the DER developers regarding what information the IOUs need to provide that would improve their ability to respond to solicitations.

CESA states that more specific locational siting information for potential projects is necessary for developers in assessing the quantity and viability of DER solutions to successfully defer a planned investment. CESA and SEIA/Vote Solar also recommend that customer-specific information is provided as part of the Request for Offers process.

For the DIDF process, we will specifically consider solicitation requirements that are specific to an individual project that need to be vetted as part of the project's viability in the DDOR and DPAG. General information requirements to include competitive solicitations, including incrementality and customer data availability will be considered in R.14-10-003. I find it reasonable that more specific locational siting information is provided to DER developers for individual projects and direct the IOUs to provide this information for projects under consideration for deferral.

9. Future DIDF Reform

Parties' additional comments on proposed improvements to the 2019 DIDF cycle have been addressed in the above sections. To consider future reforms to the DIDF process, IOUs may provide recommendations within the GNA/DDOR reports, and parties should have an opportunity to comment on December 1.

10. Other Issues

The guidance provided in this *Ruling* changes and builds upon the guidance provided in D.18-02-004. Unless changed by this *Ruling* the guidance in D.18-02-004 remains in effect. I also remind the IOUs that D.18-02-004 ordered the full GNA requirements to be implemented by 2019.

IT IS SO RULED:

Dated May 7, 2019, at San Francisco, California.

/s/ ROBERT M. MASON III

Robert M. Mason III
Administrative Law Judge

Attachment A: GNA/DDOR Requirements

Grid Needs Assessment

The GNA will include a narrative section with the following information:

1. Overview of the distribution planning process, key milestones in the process, the relationship of the process to the GNA, and how the GNA is intended to be used in DDOR
2. Overview description of the main steps of the GNA process, including but not limited to:
    a. Description of the process used to determine grid needs
    b. Any adjustments to CEC system level forecasts. IOUs may reference the DFWG report and discuss updates to the forecast, should include the level of temporal resolution and any adjustments for coincidence of load shapes
    c. Disaggregation of the system level forecast to circuits
    d. Flow chart showing process, inputs, showing where calculations use proprietary software, and how the calculations are used
    e. Assumptions and impacts of these assumptions
    f. Data sources cited with report numbers and page numbers such that a reviewer can efficiently find the data
3. All process changes since the prior GNA, including changes in content, format, methods, and data sources, should be listed and explained
4. Description of any other details that impact the forecast or that could change over time
5. An explanation of any discrepancies between GNA data and online maps
6. Any findings and proposals to modify future GNA requirements

GNA Datasets

The file creation date should be included in each tab of the datasets.

1. **Circuits, Substations, Sub-transmission Capacity Service:** Circuit-level planning assumptions and GNA digital datasets should include a unique row for distribution circuit, and substation transformer bank to include all circuits rather than just circuits with deficiencies:
    a. Peak load: five years of forecast data beginning with current year

b. DER growth: five years of forecast data beginning with current year for:

    i. Energy Efficiency
    ii. Demand Response
    iii. Residential PV
    iv. Non-Residential PV
    v. Electric Vehicles
    vi. Storage (when data is available)

c. Facility ID: This should be a unique ID, identifying the facility in correlation with forecast data

d. Substation/Circuit ID: Identify the circuit that this facility is connected to (there may be multiple facilities) Type of facility with deficiency

e. Facility loading %

f. Current year demand (MW)

g. 5 year forecasted demand (MW)

h. Forecasted percentage deficiency above the existing facility/equipment rating over five years

i. Forecasted MW deficiency over five years

j. Anticipated season or date by which distribution upgrade must be installed

2. **All Other Grid Service Needs:** Data set for all distribution facility needs that include substation and circuit level services, including reactive power, voltage, reliability, resiliency; and sub-feeder grid services should include the following:

    a. Facility ID: This should be a unique ID, identifying the facility with the deficiency

    b. Substation/Circuit ID: Identify the circuit that this facility is connected to (there may be multiple facilities)

    c. Type of facility with deficiency

    d. Distribution service required: reactive power, voltage, reliability, resiliency, etc.

    e. Anticipated season or date by which distribution upgrade must be installed

    f. Existing facility/equipment rating: MW, MVa, etc

    g. Facility loading %

    h. Forecasted deficiency % for time period that is forecasted (ie. 3 or 5 years)

<u>DDOR Section</u>

The requirements for the 2019 DDOR report will build on previous requirements. The DDOR report will detail the IOUs' planned investments that provide one or more of the four distribution services adopted by D.16-12-036 in the Integrated Distributed Energy Resource (IDER) Proceeding. We note that the appendices in PG&E 2018 DDOR report can serve as an example of what information and data should be included in forthcoming DDOR reports. DDOR report will also include a narrative section that describes the following:

1. Regulatory timeless and expected milestones in the DIDF process
2. Technical and timing screens and prioritization metrics
3. DER distribution service requirements
4. Review of DIDF projects completed and canceled from most recent cycle with project costs and contingency spending

Project Specific DDOR data

1. **Planned Investments:** Each planned investment shall be characterized by the following attributes:
   a. Project description including facility name, type and ID, substation, circuit and feeder identifiers and location, to correlate with GNA data
   b. Distribution service required: capacity, reactive power, voltage, reliability, resiliency
   c. Type of traditional capital investment equipment to be installed
   d. In-Service Date
   e. Deferrable by DERs, Y/N?
   f. Number and composition of customers by class (e.g. residential, commercial and industrial, subject to the '15x15 rule'
2. **Candidate Deferrals:** The DDOR will also present the candidate deferral project shortlist in a tiered format that results from applying deferral screens to planned investments. Justification will be given as to how the respective tiers were determined. These projects will be provided as a separate table and each candidate deferral project shall be characterized by the following attributes in addition to those attributes described above:
   a. Expected performance and operational requirements (e.g., season needed, day(s) needed, range of expected exceedances/year, expected duration of exceedances)
   b. Specific LNBA values denominated in both MW and MWh
   c. Distribution Service required

d. Expected magnitude of DER service provision (MW/kVA)

e. Duration (hours) and timing (hours of the day, which days and number of days in the year) of the deficiency and associated DER service requirements.

f. Unit cost of traditional mitigation

g. Basis for prioritization metrics including cost effectiveness (unit cost, LNBA value expressed in $/kW-yr and &/kWh-yr), forecast certainty (year of need, SCADA available and customer profile on asset) and market assessment (number of days, number of grid needs, hours per day and overcapacity percentage).

h. Contingency plans