Decision 21-09-005  September 9, 2021

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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Summary

This decision closes Rulemaking (R.) 14-08-003 in light of the opening of the successor distribution resource plan proceeding, R.21-06-017, and approves, as modified, the Investor-owned Utilities’ Application (A.) 15-07-002, A.15-07-003, and A.15-07-006, as well as the Small and Multi-Jurisdictional Utilities’ A.15-07-005, A.15-07-007, and A.15-07-008.

As illustrated in the Discussion Section of this decision, the investor-owned utilities (IOUs) (Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company, collectively referred to as the IOUs), have made progress in satisfying the requirements in Pub. Util. Code § 769 for the development and implementation of their distribution resource plan proposals. As such, this decision determines that the IOUs’ distribution resource plan proposals are in a sufficiently developed shape such that they may be approved, as modified by the decisions that the Commission has adopted in this proceeding, and by the guidance rulings the assigned Commissioner and assigned Administrative Law Judge (ALJ) have issued. Any additional work that the IOUs must undertake as required by the decisions and rulings in this proceeding to complete their distribution resource plan proposals will be overseen by the Commission in the successor distribution resource plan proceeding, R.21-06-017 (Order Instituting Rulemaking to Modernize the Electric Grid for a Higher Distributed Energy Resources Future).

The Discussion Section of this decision also demonstrates that the Small and Multi-Jurisdictional Utilities (PacifiCorp, Liberty Utilities LLC, and
Bear Valley Electric Service, Inc., collectively referred to in this Summary as SMJUs) have laid the framework for the development and implementation of their distribution resource plan proposals. While they are not as developed as the IOUs’ distribution resource plan proposals, the SMJUs have provided the Commission with enough preliminary information to approve their distribution resource plan proposals, as modified by the decisions that the Commission has adopted in this proceeding, and by the guidance rulings the assigned Commissioner and assigned ALJ have issued. Any additional work that the SMJUs must undertake as required by the decisions and rulings in this proceeding to complete their distribution resource plan proposals will be overseen by the Commission in the successor distribution resource plan proceeding, R.21-06-017.


1. Background

On August 14, 2014, the Commission opened Rulemaking (R.) 14-08-013 to establish policies, procedures, and rules to guide California electrical corporations in the development of their Distribution Resources Plan Proposals (DRP or DRPs) and to review, approve, or modify and approve the plans pursuant to Pub. Util. Code § 769. Pub. Util. Code § 769(a) defines “distributed resources” as “distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.” The Commission has been tasked in this DRP proceeding with:

- Evaluating locational benefits and costs of distributed resources located on the distribution system.¹

• Identifying additional utility spending necessary to integrate distributed resources.\(^2\)

• Identifying barriers to deployment, including safety standards and operational reliability.\(^3\)

Pub. Util. Code § 769 required the electrical corporations, which included the Investor-owned Utilities (Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company, collectively referred to as the IOUs) to file their DRP proposals that identify optimal locations for the deployment of their distributed energy resources by July 1, 2015.

On September 17, 2014, the Energy Division conducted a workshop to provide the IOUs and stakeholders with a forum to explore the issues raised by Pub. Util. Code § 769. One of the issues discussed was whether stakeholders who are part of the California Association of Small and Multi-Jurisdictional Utilities (whose members include PacifiCorp, Liberty Utilities LLC, and Bear Valley Electric Service, Inc., collectively referred to in this decision as SMJUs), whose service territories and operations are much smaller than the IOUs’, would have to make the same detailed predicate showing before the Commission would approve their DRPs.

2. **Procedural Background**

In light of the distinction between the IOUs and the SMJUs, on February 6, 2015, the Commissioner issued his *Assigned Commissioner’s Ruling On*


\(^3\) Pub. Util. Code § 769(b)(4). Pub. Util. Code § 769(b)(2) and (3) also require the Commission to evaluate proposed standard tariff and contracts needed to source distributed energy resources that provide net ratepayer benefits; and evaluate proposed cost-effective means to coordinate existing Commission programs related to distribution system planning and investments. These two requirements are being addressed in the Commission’s Integrated Distributed Energy Resources Proceeding (R.14-10-003).
Guidance for Public Utilities Code Section 769 – Distribution Resource Planning (Guidance Ruling) which set forth different filing requirements for the IOUs and the SMJUs. The Guidance Ruling attached detailed instructions for the IOUs to develop integration capacity and locational value analysis; demonstrate the capabilities of distributed energy resources (DERs) to meet grid planning and operational objectives described in the DRPs; develop data access and sharing protocols; propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources; take safety considerations into account when proposing new or modified standards for accommodating high levels of DERs; identify barriers to the deployment of DERs; coordinate the development of DRPs with utility general rate cases; develop greater granularity and accuracy in each IOU’s ability to forecast DER impact on load; develop long term planning that allows for the refinement of DRP activities and goals in various phases (Phase 1 [2016-2017]; Phase 2a [2018-2019]; and Phase 2b [Ongoing, 2018 and beyond]).

In contrast to the detailed requirements for the IOUs, the Guidance Ruling adopted a more streamlined process for approving the SMJUs’ DRP applications. For purposes of DRP guidance, SMJUs were directed to file their DRP applications and address just the five statutory requirements in Pub. Util. Code § 769 as they related to each SMJU’s distribution systems.

The IOUs filed their respective distribution resource plan applications by the July 1, 2015 deadline. Three SMJUs also filed their distribution resource plan

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4 A.15-07-002 (Southern California Edison Company (SCE)), A.15-07-003 (San Diego Gas & Electric Company (SDG&E)), and A.15-07-006 (Pacific Gas and Electric Company (PG&E)).
applications by the deadline the Commission established. The six applications were initially consolidated with the rulemaking, but following the September 30, 2015 prehearing conference (PHC), the Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge (Scoping Memo), dated January 27, 2016, ruled that the three IOU applications (A.15-07-002, A.15-07-003, and A.15-07-006) would remain consolidated with the rulemaking. But because the three SMJU applications (A.15-07-005, A.15-07-007, and A.15-07-008) were deemed different and generally less complex, the Scoping Memo determined they would be deconsolidated from the rulemaking and the IOU applications.

Because of the complexity of the issues raised by Pub. Util. Code § 769, the Scoping Memo divided the rulemaking into three tracks to better manage the evaluation of the IOUs’ DRP proposals.

**Track 1: Methodological Issues (Quasi-Legislative)**

Track 1 addressed issues related to the authorization of Demonstration Project A (Integration Capacity Analysis (ICA)), Demonstration Project B (Locational Net Benefits Analysis (LNBA)), as well as identifying, researching, and improving the ICA and LNBA methodologies. The ICA and LNBA concepts are defined as follows:

- ICA is California’s term for what is also known in the energy community as a hosting capacity analysis, wherein ICA simulates the ability of individual distribution circuits,

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5 A.15-07-005 (PacifiCorp), A.15-07-007 (Liberty Utilities LLC), and A.15-07-008 (Bear Valley Electric Service, Inc.). Originally, Bear Valley Electric Service’s application was filed by Golden State Water Company on Bear Valley Electric Service’s behalf. Since then, there has been a corporate restructuring wherein Bear Valley Electric Service and Golden State Water Company are both wholly owned subsidiaries of American States Water Company. Hereinafter, Bear Valley Electric Service will be referred to as Bear Valley.

or even “nodes” on a circuit, to accommodate additional DERs, without requiring significant upgrades to ensure system safety and reliability. In essence, this modeling exercise gathers detailed information about the distribution grid, including the physical infrastructure (the wires, voltage regulating devices, substations, transformers, etc.), the type and performance of load on the grid (load curves showing maximum and minimum load), and the existing generators and load control measures on the grid (including rooftop photo voltaic, demand response, etc.). This data is then input into a model to create a “base case” for existing grid conditions, and then simulations are run to see how the grid would perform if new DERs were added.

- LNBA evaluates DERs’ benefits at specific locations to achieve the future envisioned in the DRP where DERs are deployed at optimal locations, times, and quantities so that their benefits to the grid are maximized and utility customer costs are reduced.

The assigned Administrative Law Judge (ALJ) authorized the formation of ICA and LNBA Working Groups, consisting of the IOUs and interested stakeholders, to facilitate the identification, research, and improvement of the ICA and LNBA methodologies. The Commission’s Energy Division was tasked with overseeing the Working Groups.

**Track 2: Demonstration and Pilot Projects (Ratesetting)**

Track 2 focused on the design and authorization for Demonstration Projects C, D, and E, as designated in the February 6, 2015 Guidance Ruling. The functions of three Demonstration Projects are explained as follows:

Project C: Demonstrate DER locational benefits and validate the ability of DER to achieve net benefits consistent with the LNBA.

Project D: Demonstrate Distribution Operations and High Penetrations of
DERs. Project D calls for the utilities to integrate high penetrations of DER into their distribution planning operations. The utilities must: a) assess locational benefits and values of DER at the substation level using ICA and LNBA across multiple circuits; b) demonstrate the operations of multiple DER in concert; c) coordinate operations with third parties and customers; d) develop and explain the methodology for selection of DER types used in the project; and e) utilize both third party-owned and utility-owned resources.

Project E: Demonstrate a microgrid where DERs (both customer-owned and utility-owned) serve a significant portion of customer load and reliability services. Project D will demonstrate the use of a DER management system for controlling the resources.

**Track 3: Policy Issues (Quasi-Legislative)**

Track 3 addressed the policy issues that the parties raised in comments on the applications and in the rulemaking proceeding. Track 3 has been divided into three sub-tracks: Sub-track 1 (Growth Scenarios); Sub-track 2 (Grid Modernization); and Sub-track 3 (Distribution Investment and Deferral Process).

Ensuring compliance with Pub. Util. Code § 769 has proven to be a complex and time-consuming endeavor. As it became apparent that compliance could be completed within the statutory deadline for resolving quasi-legislative proceedings, the statutory deadline has been extended by amended scoping memos and an extension order. In addition, as the IOUs began their DRP work, it became necessary to issue supplemental guidance rulings to assist the IOUs in the completion of their various Demonstration Projects and Track requirements. We summarize those supplemental rulings and the IOUs’ responses next.
Track 1 Developments

On May 2, 2016, the assigned Commissioner issued his Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B (May 2, 2016 Ruling). The methodological refinements were set forth in Attachment A to the May 2, 2016 Ruling. The May 2, 2016 Ruling also adopted LNBA methodology for use in DRP’s Demonstration Project B, and authorized the IOUs to perform LNBA methodology for one Distribution Planning Area in each Utility’s service area.

The ICA and LNBA Working Groups met from May 2016 – March 2017 to review and make recommendations to both the short-term Demonstration A and Demonstration B Projects, as well as make recommendations for long-term methodology refinements to both ICA and LNBA.

In conformity with the May 2, 2016 Ruling, the LNBA Working Group filed its March 8, 2017 Final Report with recommendations to allow the Commission to make an informed decision regarding Demonstration Project B. On March 15, 2017, the ICA Working Group filed its Final Report which summarized the development of the ICA to date and made recommendations for the ICA methodology for the IOUS to implement across their service territories on the first system wide roll out, along with an implementation timeline and recommendations for improving the methodology.

On April 19, 2017, the assigned Commissioner issued his ruling entitled Assigned Commissioner’s Ruling Requesting Comments on the Integration Capacity Analysis and Locational Net Benefits Analysis Final Short-Term Working Group Reports (April 19 Ruling). Parties were invited to respond to a
series of questions regarding the consensus and non-consensus recommendations contained in the ICA and LNBA Working Group Reports.

On January 27, 2021, the assigned ALJ issued his *Ruling on Joint Parties’ Motion for a Order Requiring Refinements to the Integration Capacity Analysis*. Joint Parties had sought an order requiring the IOUs to refine the ICA to avoid the undetected presence of problems with ICA results in the future by the adoption of various curative measures that the *Ruling* grouped into three categories: ICA data validation refinements, continuing improvements to the DRP data portals, and compliance issues.

**Track 2 Developments**

On May 17, 2016, the assigned Commissioner and ALJ issued their *Joint Ruling Regarding track 2 Demonstration Projects* which modified the schedule for Track 2, provided the parties an opportunity to submit revised proposals on June 17, 2016, set workshops for June 28 and 29, 2016, and allowed for post-workshop comments. Pursuant to a July 6, 2016 e-mail ruling from the assigned ALJ, post-workshop comments were filed on July 22, 2016 and reply comments on July 29, 2016. In their July 29, 2016 reply comments, the Commission’s Office of Ratepayer Advocates (ORA) requested evidentiary hearings, which were held on August 10 and 11, 2016. Post-hearing comments were filed on August 26, 2016.

**Track 3 Developments**

On February 10, 2017, the Commission’s DRP team facilitated a workshop entitled *DER Growth Scenarios and Distribution Load Forecasting, Distribution Resource Planning Track 3, Sub-track 1* to consider the process and methodologies

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for forecasting the adoption of DER and distribution load to inform the DRP process. The IOUs submitted a proposed process for developing, vetting, and updating of DER Adoption Scenarios and load forecasts.

After reviewing the proposal, on February 27, 2017, the assigned Commissioner issued his *Ruling Setting Schedule for Submission of Distributed Energy Resource Growth Scenarios and Distribution Load Forecasting*. The Ruling tasked the Distribution Forecasting Working Group with clarifying the use cases, proposing the methodology and assumption for DER adoption scenarios, and developing approaches to disaggregate forecasts to the circuit level. This *Ruling* was followed by the *March 29, 2018 Joint Ruling of the Commissioner and Administrative Law Judge Establishing Parameters and Schedule for the Distribution Forecasting Working Group*.

In accordance with the above *Rulings*, the Distribution Forecasting Working Group met from April 17, 2017 to May 24, 2017, and from April 18, 2018 to June 13, 2018, to vet system-wide DER growth assumptions, load forecasting at the distribution level, and methodologies for the disaggregation of system-level DER forecasts to circuits, and filed their *Progress Report* on July 2, 2018 which included their *Final Report* dated June 28, 2018. As part of the *Final Report*, the Distribution Forecasting Working Group states that they vetted the disaggregation methods for the following five DER technologies: photovoltaic generation, electric vehicles, additional achievable energy efficiency, energy storage, and load modify demand response.
3. Discussion—IOUs

3.1. Decisions Regarding IOUs

The IOUs have worked diligently with the Commission’s Energy Division staff, the assigned ALJ’s,\(^8\) and the assigned Commissioners\(^9\) to reach a resolution of the distribution resource plan issues. As a result of party comments to various assigned ALJ rulings, scoping memos, and discussions held at various public workshops, the Commission adopted the following decisions that approved projects and provided developmental frameworks to guide the IOUs in finalizing their distribution resource plans:

- **Decision (D.) 17-02-007** addressed Track 2 Demonstration Projects and approved PG&E’s proposed Demonstration Projects C and D; approved SCE’s proposed Demonstration Projects C and D; and approved SDG&E’s proposed Demonstration Projects C and E.

- **D.17-09-026** addressed Track 1 (methodological issues) for Demonstration Project A (Integration Capacity Analysis) and Demonstration Project B (Locational Net Benefit Analysis) and adopted the ICA use cases for online maps and interconnection streamlining, as well as for distribution planning. The decision also adopted the LNBA use cases for: 1) Public Tool and Heat Map; 2) prioritization of candidate distribution deferral opportunities as part of the Distribution Investment Deferral Framework; and 3) providing location-specific avoided transmission and distribution (T&D) inputs into the Integrated Distributed Energy Resources DER Avoided Cost Calculator (DERAC) for cost-effectiveness evaluation, informing DER incentive levels, and other applications.

- **D.18-02-004** addressed the issues identified in Track 3, Sub-track 1 (Growth Scenarios) and Sub-track 3

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\(^8\) Since its opening, five different ALJs have been assigned to this proceeding.

\(^9\) Since its opening, three different commissioners have been assigned to this proceeding.
(Distribution Investment and Deferral Process) and adopted the Integrated Energy Policy Report (IEPR) demand forecast with updated Distributed Energy Resources (DER) forecasts in January 2018. The Commission ordered the IOUs to use these forecasts for their 2018-19 distribution planning cycle. The Commission ordered the IOUs to implement the Distribution Investment Deferral Framework (DIDF) as an annual planning cycle that would result in the selection of distribution upgrades from deferral through the competitive solicitation of DERs. The Commission directed the IOUs to implement DER growth scenarios and the ICA for purposes of the existing distribution planning and new DRP processes.

- D.18-03-023 addressed the issues identified in Track 3, Sub-track 2 (Grid Modernization), and provided a framework for Grid Modernization guidance to inform future general rate cases as follows:
  - Defines grid modernization with regards to its multiple objectives and the scope of Grid Modernization Plans;
  - Establishes a classification framework to serve as a common vocabulary for grid modernization investments, and terminology to guide the organization and presentation of future GRC filings;
  - Establishes the structure and timing of the grid modernization planning process, including the submission of Grid Modernization Plans and Grid Needs Assessments, and identifies how these fit into the larger Distribution Resources Planning (DRP) process;
  - Provides guidance on how the Commission will evaluate the cost effectiveness of grid modernization investments proposed in future GRCs, including net ratepayer benefits;
  - Establishes submission requirements for the grid modernization portion of future GRC requests, including how to justify each request; and
• Identifies next steps for further refining certain aspects of the grid modernization guidance adopted in this decision.

• D.20-03-005 adopted the recommendations in the Energy Division’s White Paper entitled Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values as follows:
  • First, the specified transmission and distribution deferral values will be estimated through the Distribution Investment Deferral Framework and California Independent System Operator’s Transmission Planning Process, and do not require further modeling to estimate or incorporate their values into other modeling efforts such as the Avoided Cost Calculator.
  • Second, the White Paper’s proposal for estimating the unspecified distribution deferral value will be further developed and modeled for adoption in the Avoided Cost Calculator Update in the Integrated Distributed Energy Resources R.14-10-003.
  • Third, the decision did not draw a conclusion regarding the unspecified transmission deferral value. Instead, the existing methodology shall continue to be used unless or until the Commission approves a new methodology. The Commission may continue to consider this issue in the Avoided Cost Calculator major updates in the Integrated Distributed Energy Resources Rulemaking.

Through the adoption of these various decisions, the Commission has established four key working principles for the DRP proceeding: (1) start with a comprehensive, scenario-driven, multi-stakeholder planning process that standardizes methodologies and data requirements to identify locational benefits and costs; (2) move the distribution system towards an open, flexible, and node-friendly network (rather than centralized and linear) that enables seamless
DER integration; (3) California’s electric distribution system operators (DSOs) should act as a technology-neutral marketplace to coordinate situational awareness and facilitate information exchange while avoiding conflicts of interest; (4) expedite DER participation in wholesale markets and resource adequacy (RA), unbundle distribution grid operations, create a transparent process to monetize DER services, and reduce unnecessary barriers for DER integration.

3.2. Compliance with DRP Requirements

Since their issuance, the IOUs have endeavored to comply with the decisions’ ordering paragraphs. For example, with respect to D.18-02-004.

- PG&E submitted Tier 2 Advice Letter 5688-E for approval to issue competitive solicitations to procure distributed energy resources solutions for its identified electric distribution deferral opportunities.\(^\text{10}\)
- SCE submitted Tier 2 Advice Letter 4108-E and sought approval to launch a Distribution Investment Deferral Framework Request for Offers to procure distributed energy resources that can defer specific distribution projects.\(^\text{11}\)
- SDG&E submitted Tier 2 Advice Letter 3467-E and informed Energy Division that there were no proposed candidate deferral projects that necessitate a solicitation process to procure a cost-effective distributed energy resource solution to defer a candidate deferral project.

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\(^\text{10}\) PG&E’s projects are Alpaugh New Feeder, Calfax Bank 2, Santa Nella Bank and New Feeder, and FMC 1102.

\(^\text{11}\) SCE’s projects are Eisenhower project, Saugus-Newhall #1 and #2 Subtransmission Line Project, Pechanga Project, Alessandro Project, Saugus Subtransmission Line Project #1 (Saugus-Elizabeth Lake -MWD Foothill 66kV Subtransmission Line), and Saugus Subtransmission Line Project #2 (Saugus-Colossus-Lockheed-Pitchgen 66 kV Subtransmission Line).
Energy Division approved these Advice Letters on December 10 (PG&E and SCE) and December 18 (SDG&E), 2019. Since then, the IOUs have continued their compliance efforts. The Commission’s February 2021 report entitled *California’s Grid Modernization Report to the Governor and Legislature* summarizes their progress:

The CPUC approved over 16 megawatts (MW) of PG&E battery storage contracts and 18.5 MW battery storage contracts for SCE. To date, SDG&E has not had any deferrals. The CPUC also approved the launch of nine DIDF solicitations scheduled for January 2021.

### 3.3. Information Gathering and Guidance Rulings

As the IOUs endeavored to comply with the Commission’s decisions, they encountered some difficulties in their ability to comply because of perceived uncertainty in the Commission’s requirements or because of changes in factual/market circumstances that made compliance impractical. Thus, it became necessary to provide the IOUs with the following additional information gathering and guidance rulings.

On February 29, 2019, the ALJ issued his Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework Process.

Based on the comments received, on May 7, 2019, the ALJ issued his *Ruling Modifying the Distribution Investment Deferral Framework Process*.

On November 8, 2019, the ALJ issued his Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process.

On April 13, 2020, the ALJ issued his *Ruling Modifying the Distribution Investment Deferral Framework Process*, which updated the Independent
Professional Engineer (IPE) scope of work for the DIDF process and provided the 2020-2021 DIDF cycle schedule.

On May 11, 2020, the ALJ issued his *Ruling Modifying the Distribution Investment Deferral Framework – Filing and Process Requirements*, which further modified the DIDF process and filing requirements by focusing on party comments and reforms related to aspects of the DIDF that were not addressed in the *April 13, 2020 Ruling*.

On January 27, 2021, the ALJ issued his *Ruling on Joint Parties’ Motion for an Order Requiring Refinements to the Integration Capacity Analysis (January 27,2021 Ruling)* which adopted the proposal to have the IOUs develop a description of the uniform load methodology, inputs, and assumptions.

On June 21, 2021, the ALJ issued his *Ruling on Recommended Reforms for the Distribution Investment Deferral Framework Process*. One of the new reforms adopted for the 2021-2022 DIDF Cycle was designed to promote greater transparency and understanding of the IOUs’ DIDF contracting process:

> Every six months IOUs shall submit to ED a DIDF Procurement Status Report noting the status of all DIDF contracts (RFO, SOC, Partnership Pilot), expected Date of Service, any modifications made to any contracts under the DIDF. The report shall include clear tables with current DIDF contract data as well as DIDF contract data from every DIDF cycle to date (including the prior Integrated Distributed Energy Resource (IDER) Pilots). A public version shall be shared with the DPAG and a confidential version with Energy Division.\(^\text{12}\)

With the adoption of these decisions, along with guidance and modification rulings that the Commissioner and ALJ has prepared in

\(^{12}\) *June 21, 2021 Ruling*, at 5.
collaboration with the Commission’s Energy Division DRP staff, the Commission finds that the IOUs have made significant strides towards satisfying the requirements of Pub. Util. Code § 769. Most recently, on May 28, 2021, in response to the January 27, 2021 Ruling, the IOUs submitted their Tier 1 Advice Letters requesting approval of their improved ICA data validation plans which, if successfully implemented, will develop a more accurate determination of how much incremental load and generation the distribution system can host on existing system configurations without modifications.

Collectively, the IOUs’ work in following the adopted frameworks and guidance has achieved a number of important energy policy objectives that the Commission believes will benefit California ratepayers including, but not limited to: (1) developing new tools, processes, and investment frameworks that have enabled IOUs to better integrate distribution energy resources into grid operations and the annual distribution planning process, reducing greenhouse gas emissions; (2) modernizing the distribution system to accommodate two-way energy flows; (3) enabling customer choice of new technologies and services that reduced emissions and improved reliability; and (4) realizing opportunities for distributed energy resources to provide benefits through the provision of grid services.

But given the complexity of the issues that the Commission and the parties faced in meeting the DRP requirements, it has become clear that compliance with all DRP requirements and goals will not be achieved in the life of one DRP proceeding. Thus, while approving, as modified, the IOUs’ DRP applications and closing this proceeding, the Commission expects the IOUs will continue to develop their DRP plans in the successor DRP proceeding, R.21-06-017 in conformity with the developmental frameworks adopted, as well as the guidance
rulings provided, in this proceeding. R.21-06-017 expressed the intent to transfer all unresolved issues and the records related thereto from R.14-08-013 into the successor proceeding.\(^\text{13}\) For now, the chart below summarizes the status of IOU compliance with the requirements of Pub. Util. Code § 769.

**Table 1: Pub. Util. Code § 769 Requirements and IOU Compliance**

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<td>Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resource provides to the electric grid or costs to ratepayers of the electrical corporation.</td>
<td>• D.17-09-026 established LNBA &amp; ICA methodologies, and the IOUs have identified use cases for further development and evaluation.&lt;br&gt;• Distribution Forecasting Working Group has been established and generated annual growth scenario updates.&lt;br&gt;• DRP Data Portals have been established.&lt;br&gt;• Annual DIDF procurement process has been established.&lt;br&gt;• Additional refinements to the above list and with respect to meeting this PUC requirement are ongoing and will be addressed in successor DRP proceeding, R.21-06-017.</td>
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<td>Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.</td>
<td>• This requirement has been scoped into the IDER proceeding, R.14-10-003, and addressed in D.18-02-004 for Competitive Solicitation Framework and D. 21-02-006 for IDER Tariffs.&lt;br&gt;• Ongoing implementation will continue in the successor DRP proceeding, R.21-06-017.&lt;br&gt;• Additional refinements to the above list and with respect to meeting this PUC requirement are ongoing and will continue in the successor DRP proceeding, R.21-06-017.</td>
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\(^\text{13}\) See R.21-06-017, at 4, fn. 7.
Propose cost-effective methods of effectively coordinating existing commission approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

- This requirement has been scoped into the IDER proceeding, R.14-10-003.
- Additional refinements with respect to meeting this PUC requirement are ongoing and will be continued in the successor DRP proceeding, R.21-06-017.

Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

- Grid Modernization Guidance for GRC Applications was established in D.18-03-023.
- Specific funding requests will be made through each IOU’s GRC.
- Additional refinements to the above list and with respect to meeting this PUC requirement are ongoing and will be continued in the successor DRP proceeding, R.21-06-017.

4. Discussion—SMJU

As can be seen above by the sequence of events, rulings, and decisions, the bulk of this proceeding has been devoted to the IOUs’ DRP applications and demonstration projects considering their complexity. That has left the SMJU’s simplified DRP applications in a trailing position as the Commission grappled for the past seven years with the nuances and challenges presented by the IOUs’ DRP applications.

The posture of the SMJU DRP applications, however, does not lead to the conclusion that they should be denied. In fact, based on the information provided in their respective applications and supporting documentation, the SMJUs have laid the framework for the development and implementation of DRP proposals such that they should be approved, as modified by the decisions and rulings in this proceeding. Any further SMJU development and implementation of their DRP applications should occur within the jurisdictional
confines of the successor DRP proceeding, R.21-06-017, wherein the Commission can both oversee the SMJUs’ progress and provide any additional guidance rulings and decisions, as needed.

But to justify our decision today to approve the SMJU DRP applications, as modified, it will be helpful to identify the SMJUs and explain how the information provided in their respective filings have laid the framework for the development and implementation of their distribution resource plan proposals.

4.1. **The SMJU Applications**

**Bear Valley**

Bear Valley identifies itself as a small electric utility in the Big Bear recreational area of the San Bernadino Mountains that provides electric distribution service to approximately 21,900 residential customers, and 1,400 commercial, industrial, and public authority customers. Its service territory is connected to the California Independent System Operator (CAISO) via SCE’s system, making it a distribution customer of SCE.

Bear Valley states that its distribution planning “is conducted by significantly smaller staffs” than at the IOUs. It states that it has less than 50 employees and approximately 23,300 customers compared to SCE’s 3,599 employees and 4.97 million customers.

**Liberty Utilities**

Liberty Utilities states it serves approximately 49,000 electric customers in California, in and around the western portions of the Lake Tahoe Basin. Its California customers are located in portions of Placer, El Dorado, Nevada, Sierra, Plumas, Mono, and Alpine Counties. Per Liberty Utilities, the electric load within the service territory reflects the economic activities in the area—little manufacturing or heaving industry. Instead, the economy is dominated my
tourism with the major businesses being hotels, motels, and ski resorts, with approximately half of the electricity delivered to residential customers and approximately 60% of the residential accounts are second-family homes or rentals.

**PacifiCorp**

PacifiCorp states it provides electric retail service to customers in California, Idaho, Oregon, Utah, Washington, and Wyoming, with 45,000 customers located in portions of Del Norte, Modoc, Shasta, and Siskiyou counties in Northern California. While the geographic area is large, it has low population centers, with an average of 3.9 customers per square mile.

### 4.2. SMJU’s Simplified DRP Plans

**Table 2: SMJU Pub. Util. Code § 769 Compliance Status**

<table>
<thead>
<tr>
<th>PUC § 769 requirement</th>
<th>Bear Valley</th>
<th>Liberty Utilities</th>
<th>PacifiCorp</th>
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</thead>
<tbody>
<tr>
<td>Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure,</td>
<td>Bear Valley claims it has 165 distributed renewable generation facilities on its distribution system with another 40 pending. All are customer owned and part of Bear Valley’s net energy metering program (NEM). The solar generation displaces power needs and</td>
<td>Liberty Utilities claims it’s NV Energy Services Agreement allows for local distributed generation capacity up to 5 MW. It has only 50 distributed renewable generation facilities on its distribution system. Liberty says it offers six energy efficiency programs and measures to help customers save energy and money. Liberty claims to offer EV charging stations</td>
<td>PacifiCorp claims that it’s filed its 2015 IRP showing resource needs can be met with demand side management and short-term market purchases through 2027.</td>
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<tr>
<td>Safety benefits, reliability benefits, and any other savings the distributed resource provides to the electric grid or costs to ratepayers of the electrical corporation.</td>
<td>Reduces power supply requirements from CAISO. Offers energy efficiency programs for its residential and commercial customers. The one demand response program targets its four largest customers through a time-of-use interruptible tariff.</td>
<td>At both of its offices and plans to offer additional stations. Liberty offers a voluntary residential TOU rate.</td>
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<td><strong>Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.</strong></td>
<td>While this matter has been scoped into R.14-10-003, Bear Valley states it offers two programs/tariffs and three TOU programs/tariffs. Bear Valley says it expects to pursue utility-owned solar and EV charging stations.</td>
<td>While this matter has been scoped into R.14-10-003, Liberty claims it’s NEM tariff gives customers the ability to add their own electrical generation that is used to offset part of all of customer electrical requirements.</td>
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<tr>
<td><strong>Propose cost-effective methods of effectively coordinating existing</strong></td>
<td>With its solar initiative, Bear Valley claims to forecast steep growth in the installation of</td>
<td>PacifiCorp states it does not have specific proposals currently.</td>
<td></td>
</tr>
<tr>
<td>Commission approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.</td>
<td>Solar resources, with the rebate provided reducing the cost of distributed resources.</td>
<td>Management program, and distribution infrastructure improvement program.</td>
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<tr>
<td>Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.</td>
<td>Bear Valley claims its EV charging station pilot program is estimated to cost $120-320,000.</td>
<td>Liberty states it does not propose additional spending as its current tariff gives customers the opportunity to offset usage with renewable energy.</td>
<td>PacifiCorp says it plans to evaluate additional tools and software to further enable study DER and evaluate tools utilized by the IOUs for applicability to PacifiCorp.</td>
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<tr>
<td>Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution.</td>
<td>Bear Valley says it must monitor the effects of continued growth on revenue and the cost benefits for all customers.</td>
<td>Liberty states it encounters barriers stemming from the unique weather, topography, and dense vegetation/forestation of its service territory.</td>
<td>PacifiCorp says its Policy 138, Distributed Energy Resource Interconnection Policy, explains the technical requirements for interconnection of generators to PacifiCorp’s distribution system, and the</td>
</tr>
</tbody>
</table>
circuit in a manner that ensures reliable service.

technology needed to keep up to ever evolving DERs.

The Commission may require SMJUs to update this information in the successor DRP proceeding, R.21-06-017.

5. **Comments on Proposed Decision**

   The proposed decision of Commissioner Darcie L. Houck in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission’s rules of Practice and Procedure. Opening comments were received on August 26, 2021, from Green Power Institute, who was supportive of the decision. No reply comments were received.

6. **Assignment of Proceeding**

   Darcie L. Houck is the assigned Commissioner and Robert M. Mason III is the assigned ALJ in these proceedings.

**Findings of Fact**

1. PG&E has provided the Commission with proof of its current compliance efforts with Pub. Util. Code § 769.

2. SDG&E has provided the Commission with proof of its current compliance efforts with Pub. Util. Code § 769.

3. SCE has provided the Commission with proof of its current compliance efforts with Pub. Util. Code § 769.


5. Liberty Utilities has provided the Commission with proof of its current compliance efforts with Pub. Util. Code § 769.

Conclusion of Law

1. It is reasonable to conclude that SCE’s A.15-07-002 should be approved, as modified by the decisions and rulings in this proceeding.

2. It is reasonable to conclude that SDG&E’s A.15-07-003 should be approved, as modified by the decisions and rulings in this proceeding.

3. It is reasonable to conclude that PacifiCorp’s A.15-07-005 should be approved, as modified by the decisions and rulings in this proceeding.

4. It is reasonable to conclude that PG&E’s A.15-07-006 should be approved, as modified by the decisions and rulings in this proceeding.

5. It is reasonable to conclude that Liberty Utilities’ A.15-07-007 should be approved, as modified by the decisions and rulings in this proceeding.

6. It is reasonable to conclude that Bear Valley’s A.15-07-008 should be approved, as modified by the decisions and rulings in this proceeding.


8. It is reasonable to conclude that any additional DRP work that the Commission may require SCE, SDG&E, PG&E, PacifiCorp, Liberty Utilities, and Bear Valley to perform shall be completed in the successor DRP proceeding, R.21-06-017.

ORDER

IT IS ORDERED that

1. Southern California Edison Company’s (SCE) Application 15-07-002 is approved, as modified by the decisions and rulings in this proceeding. Any
further distribution resources plan (DRP) work that the Commission requires
SCE to perform shall be completed in the successor DRP proceeding,
Rulemaking 21-06-017.

2. San Diego Gas & Electric Company’s (SDG&E) Application 15-07-003 is
approved, as modified by the decisions and rulings in this proceeding. Any
further distribution resources plan (DRP) work that the Commission requires
SDG&E to perform shall be completed in the successor DRP proceeding,
Rulemaking 21-06-017.

3. PacifiCorp’s Application 15-07-005 is approved, as modified by the
decisions and rulings in this proceeding. Any further distribution resources plan
(DRP) work that the Commission requires PacifiCorp to perform shall be
completed in the successor DRP proceeding, Rulemaking 21-06-017.

4. Pacific Gas and Electric Company’s (PG&E) Application 15-07-006 is
approved, as modified by the decisions and rulings in this proceeding. Any
further distribution resources plan (DRP) work that the Commission requires
PG&E to perform shall be completed in the successor DRP proceeding,
Rulemaking 21-06-017.

5. Liberty Utilities LLC’s (Liberty Utilities) Application 15-07-007 is
approved, as modified by the decisions and rulings in this proceeding. Any
further distribution resources plan (DRP) work that the Commission requires
Liberty Utilities to perform shall be completed in the successor DRP proceeding,
Rulemaking 21-06-017.

6. Bear Valley Electric Service, Inc.’s (Bear Valley) Application 15-07-008 is
approved, as modified by the decisions and rulings in this proceeding. Any
further distribution resources plan (DRP) work that the Commission requires
Bear Valley to perform shall be completed in the successor DRP proceeding, Rulemaking 21-06-017.


8. All matters in Rulemaking (R.) 14-08-013, Application (A.) 15-07-002, A.15-07-003, A.15-07-005, A.15-07-006, A.15-07-007, and A.15-07-008 have been decided or will be transferred to the successor proceeding R.21-06-017.

This order is effective today.

Dated September 9, 2021, at San Francisco, California.

MARYBEL BATJER
President
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
DARCIE HOUCK
Commissioners